Cenovus delivers strong operational performance in 2016
Higher oil sands production, lower costs

Calgary, Alberta (February 16, 2017) – Cenovus Energy Inc. (TSX: CVE) (NYSE: CVE) delivered strong, safe and reliable operating performance in 2016. The company increased its oil sands production compared with 2015 and achieved further cost efficiencies, including decreased operating and general and administrative (G&A) expenses as well as lower oil sands sustaining capital costs. The sustaining capital improvements have contributed to lower future development costs for Cenovus's oil sands business.

"Our operations performed exceptionally well in 2016, and we remained financially resilient through a difficult macro environment that included a 13-year low in benchmark oil prices in the first quarter," said Brian Ferguson, Cenovus President & Chief Executive Officer. "Our continued focus on costs allowed us to maintain a strong balance sheet and execute our original business plan for the year with lower capital spending than we had planned. This has put us in an excellent position to pursue disciplined growth in 2017 and beyond."

Key 2016 developments

- Added oil sands production capacity of 80,000 barrels per day (bbls/d) gross
- Increased oil sands production by 7% compared with 2015
- Reduced oil sands per-barrel non-fuel operating costs by 13% compared with 2015
- Increased proved reserves by 5% compared with 2015
- Funded Cenovus's capital program and dividend, and generated free funds flow (previously labelled "free cash flow")* with West Texas Intermediate (WTI) averaging below US$45/bbl in 2016
- Exited the year with $3.7 billion in cash and $4 billion in undrawn credit facilities

2016 production & financial summary

(for the period ended December 31) Production (before royalties)	**2016 Q4**	2015 Q4	% change	**2016 Full year**	2015 Full year	% change
Oil sands (bbls/d)	**164,396**	139,413	18	**149,693**	140,320	7
Conventional oil[1] (bbls/d)	**55,155**	60,143	-8	**56,165**	66,627	-16
Total oil (bbls/d)	**219,551**	199,556	10	**205,858**	206,947	-1
Natural gas (MMcf/d)	**379**	424	-11	**394**	441	-11
Financial ($ millions, except per share amounts)						
Cash from operating activities	**164**	322	-49	**861**	1,474	-42
Adjusted funds flow[2] (previously labelled "cash flow")*	**535**	275	95	**1,423**	1,691	-16
Per share diluted	**0.64**	0.33		**1.71**	2.07	
Operating earnings[2]	**321**	-438		**-377**	-403	
Per share diluted	**0.39**	-0.53		**-0.45**	-0.49	
Net earnings	**91**	-641		**-545**	618	
Per share diluted	**0.11**	-0.77		**-0.65**	0.75	
Capital investment	**259**	428	-39	**1,026**	1,714	-40

[1] Includes natural gas liquids (NGLs).

[2] Adjusted funds flow and operating earnings are non-GAAP measures. For more information, refer to the Non-GAAP Measures section of the Advisory at the end of this news release.

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*For more information on this and certain other changes related to disclosure of non-GAAP measures, refer to the Non-GAAP Measures section of the Advisory at the end of this news release.

Overview

Oil production

In 2016, Cenovus achieved first oil at its Christina Lake phase F and Foster Creek phase G expansion projects. The expansions increased the company's total oil sands production capacity by 26%, or 80,000 bbls/d gross, to 390,000 bbls/d gross. Incremental volumes from the new phases contributed to fourth quarter oil sands production, net to Cenovus, of more than 164,000 bbls/d and full-year production of nearly 150,000 bbls/d net, a 7% increase from full-year 2015. The ramp-up at both expansion phases is progressing well and is expected to be completed in 2017. The Christina Lake phase F expansion included the commissioning of a 100 megawatt natural gas fired cogeneration plant which provides reliable, energy-efficient power to the project.

Conventional oil production in 2016 was more than 56,000 bbls/d, a 16% decrease from the previous year, largely due to expected natural declines and the company's 2015 sale of its royalty interest and mineral fee title lands business. In 2016, Cenovus's conventional oil and natural gas assets combined generated $374 million in operating margin (previously labelled "operating cash flow")* net of capital investment to help support growth in the company's oil sands business.

Building on its successes in 2016, Cenovus will continue to pursue disciplined growth in 2017. The company plans to resume investment in its phase G expansion at Christina Lake. Cenovus anticipates the expansion can be completed with go-forward capital investment of between $16,000 and $18,000 per flowing barrel. Module assembly has already resumed for phase G, which has an expected design capacity of 50,000 bbls/d gross, and field construction is expected to ramp up to full activity by mid-year as modules are delivered to the site. First oil from phase G is expected in the second half of 2019.

Cenovus has also launched a targeted conventional drilling program on the Palliser Block in southern Alberta, where the company has a large inventory of attractive short-cycle tight oil opportunities. To date, Cenovus has identified approximately 700 drilling locations and plans to spend approximately $160 million in 2017 to drill about 50 horizontal development wells and 60 stratigraphic wells at Palliser.

At its Investor Day in June 2017, Cenovus intends to provide an update on its plans for Foster Creek phase H and Narrows Lake phase A, including expectations for capital costs and timing for each project. Foster Creek phase H has an expected design capacity of 30,000 bbls/d and Narrows Lake phase A has an expected design capacity of 45,000 bbls/d. The company continues to advance engineering work on the two deferred expansion projects using the same rigour that was applied to Christina Lake phase G.

"We have the financial strength to reinvest in Foster Creek phase H and Narrows Lake phase A, once we're confident we've defined the best possible development plans," said Ferguson. "With two new expansion phases already ramping up, our planned construction of Christina Lake phase G and potential restarts at Foster Creek and Narrows Lake, we have a clear line of sight to five years of growth that would take our oil sands production capacity to more than half a million barrels per day gross."

Cost reductions

In 2016, Cenovus achieved significant reductions in its per-barrel oil operating costs. Oil sands operating costs were $8.91/bbl in 2016, a 12% decrease from the previous year, while non-fuel oil sands operating costs were $6.65/bbl, a 13% decline compared with 2015 and 30% lower than in 2014. At Cenovus's conventional oil assets, despite expected production declines, per-unit operating costs continued to improve, falling 10% to $14.18/bbl compared with 2015 and 24% compared with 2014.

"I'm extremely pleased with the progress we've made to date with our overall cost structure," said Ferguson. "The cost reductions and operational improvements we've achieved over the past two years have enabled us to fund our capital program, pay our dividend and generate free funds flow in 2016 with WTI prices averaging below US$45 per barrel."

In 2016, Cenovus continued to achieve meaningful reductions in the capital required to sustain its base business and maintain ongoing production, particularly at its oil sands operations. The company had 2016 oil sands sustaining capital of approximately $7.00/bbl, a decrease of 33% from 2015 and 50% from 2014. This improvement in sustaining capital costs contributed to 2016 capital spending at the low end of Cenovus's guidance and reduced future development costs across the company's oil sands reserves and resources base.

Cenovus had G&A costs of $326 million in 2016, down from $335 million in 2015. The 2016 G&A costs included a $61 million non-cash expense related to office building leases in Calgary that exceed Cenovus's current and near-term requirements. Cenovus also had severance payments of $19 million in 2016 compared with $43 million in 2015. Excluding the lease-related and severance charges, G&A costs would have been $246 million in 2016, 16% lower than the previous year and 35% lower than in 2014.

Financial performance

Benchmark commodity prices remained volatile in 2016, with WTI falling to nearly US$26/bbl in the first quarter before gradually increasing to almost US$54/bbl by the end of the year. As a result, Cenovus received 12% less for its crude oil in 2016 compared with the previous year. The company also received 21% less for its natural gas than in 2015. This contributed to a 16% decline in adjusted funds flow to $1.4 billion.

The Wood River and Borger refineries in the U.S., which are jointly owned with the operator, Phillips 66, had strong operational performance in 2016. Higher crude oil runs and refined product output partially offset a decline in refining and marketing operating margin that was primarily driven by a 32% decline in average market crack spreads compared with 2015. Operating margin from refining and marketing was $346 million in 2016, a decline of 10% from the previous year.

Cenovus has an active hedging program to support cash outflows and help maintain financial resilience. As of December 31, 2016, the company had hedges in place on approximately 65,000 bbls/d of crude oil for 2017. About 39% of these barrels are hedged using costless collars, which set an average minimum price of US$44.84/bbl and average maximum price of US$56.47/bbl that the company will receive for its hedged oil. This limits downside risk on the hedged barrels while giving the company some ability to benefit in a rising price environment.

Board succession
Michael A. Grandin is retiring as Chair of Cenovus's Board of Directors at the conclusion of the company's Annual General Meeting on April 26, 2017. At that time, longstanding Cenovus Board member Patrick D. Daniel will succeed Mr. Grandin as Chair of the Board of Directors.

Mr. Grandin was appointed Chair of Cenovus's Board of Directors when the company launched in 2009 and has also served as the Chair of the Board's Nominating and Corporate Committee for all of that time.

"Michael Grandin's steadfast guidance of Cenovus since its earliest days has been invaluable to the success of our company. He's positioned the Board and the company well as we continue our journey, and we wish him an equally rewarding retirement," said Ferguson. "We're fortunate that Patrick Daniel, a seasoned Cenovus Board member with a wealth of business experience, is able to seamlessly transition into the role of Chair."

Mr. Daniel has also served on Cenovus's Board of Directors since the company's inception and currently sits on its Audit, Human Resources and Compensation, and Nominating and Corporate Governance committees. He was previously President & Chief Executive Officer of Enbridge Inc. More information about Mr. Grandin, Mr. Daniel and Cenovus's Board of Directors is available on the company's website at cenovus.com under About us.

2016 and fourth quarter details

Oil sands

Foster Creek
- Production averaged 70,244 bbls/d net in 2016, 7% more than in 2015, following a targeted well maintenance program in the first half of the year and the start-up of phase G in the third quarter of 2016.
- In the fourth quarter, production averaged 81,588 bbls/d net, a 28% increase from the same period in 2015.
- Operating costs declined 16% to $10.55/bbl in 2016 from the previous year. Non-fuel operating costs were $8.09/bbl, a 17% decrease from 2015.
- The steam to oil ratio (SOR), the amount of steam needed to produce one barrel of oil, was 2.7 in 2016 compared with 2.5 in 2015.

Christina Lake
- Production averaged 79,449 bbls/d net in 2016, an increase of 6%, largely due to the start-up of expansion phase F, which began contributing volumes in the fourth quarter of 2016.
- In the fourth quarter, production averaged 82,808 bbls/d net, a 9% increase from the same period in 2015.
- Cenovus's new 100 megawatt natural gas fired cogeneration plant began operating in the fourth quarter. Excess power not currently required for operations at Christina Lake is being sold into the Alberta electricity grid.
- Operating costs were $7.48/bbl in 2016, a 7% decline from a year earlier. Non-fuel operating costs were $5.40/bbl, 7% lower than in 2015.
- The SOR was 1.9 in 2016 compared with 1.7 a year earlier.

Conventional oil

- Total conventional oil production decreased 16% to 56,165 bbls/d in 2016 compared with the previous year, primarily due to expected natural reservoir declines. The 2015 sale of the company's royalty interest and mineral fee title lands business also contributed to the year-over-year decrease. The divested assets produced an average of 2,555 bbls/d in 2015.
- Production was 55,155 bbls/d net in the fourth quarter, a decline of 8% from the same period in 2015.
- Despite expected production declines, operating costs were $14.18/bbl in 2016, 10% lower than in 2015.

Natural gas

- Natural gas production averaged 394 million cubic feet per day (MMcf/d) in 2016, down 11% from a year earlier, primarily due to expected natural declines. The 2015 sale of the company's royalty interest and mineral fee title lands business also contributed to the year-over-year decrease in natural gas volumes.
- In the fourth quarter, natural gas production declined 11% to 379 MMcf/d compared with the same period in 2015.
- Despite expected production declines, unit operating costs fell 4% to $1.15 per thousand cubic feet (Mcf) in 2016 compared with a year earlier.

Downstream

- The Wood River Refinery in Illinois and Borger Refinery in Texas, which Cenovus jointly owns with the operator, Phillips 66, processed a combined average of 444,000 bbls/d gross of oil (97% utilization) in 2016, compared with 419,000 bbls/d gross in 2015 (91% utilization).
- Cenovus had refining and marketing operating margin of $346 million in 2016, compared with $385 million in 2015. The company's refining operating margin 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 operating margin from refining and marketing would have been $108 million lower in 2016. In 2015, operating margin would have been $52 million higher on a LIFO reporting basis.

Financial

Corporate and financial information

- Operating margin was $1.8 billion in 2016, a 28% decrease from 2015, largely due to lower commodity prices. The decrease was also due to lower realized risk management gains of $237 million, excluding refining and marketing, compared with gains of $613 million in 2015, as well as an 11% decline in natural gas sales volumes and lower operating margin from refining and marketing.
- Cash from operating activities and adjusted funds flow declined largely due to the decrease in operating margin, partially offset by cash tax recovery and lower workforce costs. In 2016, cash from operating activities declined 42% to $861 million and adjusted funds flow declined 16% to $1.4 billion compared with 2015.
- After investing just over $1 billion in 2016, Cenovus had free funds flow of $397 million, compared with a free funds flow shortfall of $23 million a year earlier.
- Cenovus had a 2016 operating loss of $377 million compared with an operating loss of $403 million in 2015. The smaller loss in 2016 was primarily due to a decline in

depreciation, depletion and amortization (DD&A) related to lower DD&A rates and asset impairments, and a decline in exploration expense.

- Cenovus had a net loss of $545 million in 2016. This compares with net earnings of $618 million in 2015 when the company recorded an after-tax gain of approximately $1.9 billion from the sale of its royalty interest and mineral fee title lands business.
- The company had G&A costs of $326 million in 2016, down from $335 million in 2015. The 2016 G&A costs included a $61 million non-cash expense related to office building leases in Calgary that exceed Cenovus's current and near-term requirements. Cenovus also had severance payments of $19 million in 2016 compared with $43 million in 2015. Excluding the lease-related and severance charges, G&A costs would have been $246 million in 2016, 16% lower than the previous year and 35% lower than in 2014. The decrease from 2015 was primarily due to lower costs for workforce and information technology.
- The company ended 2016 with cash and cash equivalents of approximately $3.7 billion as well as $4 billion in undrawn capacity under its committed credit facility, and no debt maturities until the fourth quarter of 2019. At the end of 2016, Cenovus's net debt to capitalization was 18% compared with 16% at the end of 2015. The company's net debt to adjusted earnings before interest, taxes, depreciation and amortization (EBITDA) was 1.9 times on a trailing 12-month basis compared with 1.2 times at the end of 2015.
- For the first quarter of 2017, the Board of Directors has declared a dividend of $0.05 per share, payable on March 31, 2017 to common shareholders of record as of March 15, 2017. Based on the February 15, 2017 closing share price on the Toronto Stock Exchange of $17.97, this represents an annualized yield of about 1%. Declaration of dividends is at the sole discretion of the Board and will continue to be evaluated on a quarterly basis.

Reserves and resources

All of Cenovus's proved and probable reserves and resources recoverable using established technology are evaluated each year by independent qualified reserves evaluators (IQREs).

- At the end of 2016, Cenovus had total proved reserves of approximately 2.7 billion barrels of oil equivalent (BOE), an increase of 5% compared with 2015. Proved reserves additions of 221 million BOE included approximately 154 million barrels resulting from regulatory approval of an area expansion at Christina Lake, which converted probable reserves into proved reserves, and 61 million barrels from improved reservoir performance across the company's oil sands business.
- Total proved plus probable reserves were relatively unchanged at 3.8 billion BOE, as reserves additions related to improved reservoir performance at Foster Creek and Christina Lake mostly offset production.
- Based on IQRE evaluation of Cenovus's bitumen reserves, estimated future capital costs to develop the company's remaining proved undeveloped bitumen reserves declined to approximately $8.00/bbl in 2016 compared with approximately $9.00/bbl the previous year.
- Cenovus's 2016 proved reserves finding and development (F&D) costs were $3.49/BOE, excluding changes in future development costs, down 34% from $5.31/BOE in 2015, due to reduced capital spending. Three-year average F&D costs were $7.14/BOE, excluding changes in future development costs. The 2016 recycle ratio was 3.2 times.
- More details about Cenovus's reserves and contingent resources are available under Financial Information in the Advisory. Further information about the company's

reserves is also available in Cenovus's Annual Information Form (AIF), while additional details about its resources can be found in the supplemental Statement of Contingent and Prospective Resources. These documents are available on SEDAR at sedar.com, EDGAR at sec.gov and Cenovus's website at cenovus.com.

Year-end disclosure documents

Today, Cenovus Energy Inc. is filing its audited Consolidated Financial Statements for the year ended December 31, 2016 as well as related Management's Discussion and Analysis with Canadian securities regulatory authorities. Cenovus is also filing today its AIF for the year ended December 31, 2016, which includes disclosure relating to reserves data and other oil and gas information. In addition, the company is filing its Statement of Contingent and Prospective Resources as at December 31, 2016, which includes information relating to bitumen best estimate economic contingent resources and bitumen prospective resources. Cenovus is also filing its Annual Report on Form 40-F for the year ended December 31, 2016 with the U.S. Securities and Exchange Commission. Copies of these documents will be available today on SEDAR at sedar.com, EDGAR at sec.gov (for the Form 40-F), and the company's website at cenovus.com under Investors. They can also be requested by email at investor.relations@cenovus.com.

Other developments

In December 2016, Cenovus announced it had been placed in the Leadership level of the annual CDP Climate Change Report. This global ranking recognizes actions the company has taken to manage climate change impacts within its operations and beyond. The score of A- positions Cenovus in the top quartile of all global companies assessed by CDP and as one of only two Canadian energy companies at the Leadership level. These results were announced on December 8, 2016 as part of CDP's Canada Report.

Conference Call Today

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

Cenovus will host a conference call today, February 16, 2017, starting at 9 a.m. MT (11 a.m. ET). To participate, please dial 888-231-8191 (toll-free in North America) or 647-427-7450 approximately 10 minutes prior to the conference call. 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 adjusted funds flow (previously labelled cash flow), operating earnings (loss), free funds flow (previously labelled free cash flow), net debt to adjusted EBITDA and net debt to capitalization. These are non-GAAP measures, which do not have standardized meanings and may not be comparable to similar measures presented by other issuers. Adjusted funds flow, operating earnings (loss) and free funds flow are defined and reconciled to IFRS measures in the Financial Results section of the company's Management's Discussion and Analysis for the year ended December 31, 2016 (the "MD&A"). Net debt to adjusted EBITDA and net debt to capitalization are defined and reconciled to IFRS measures in the Liquidity and Capital Resources section of the MD&A. These non-GAAP measures are presented because they are used by management to analyze Cenovus's liquidity and ability to generate funds to finance its operations. This information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. For further information, refer to the MD&A.

Cenovus previously identified operating cash flow (now relabelled operating margin) as a non-GAAP measure. However, the company has determined that this measure is more appropriately characterized as an additional subtotal, as it is found in note 1 of the company's consolidated financial statements for the year ended December 31, 2016 (the "Financial Statements"). Cenovus has not changed the composition of the measure. For more information regarding operating margin, refer to note 1 of the Financial Statements.

Oil and gas metrics

F&D costs are calculated by dividing the sum of total exploration and development costs incurred in 2016 by the sum of total additions and revisions for proved reserves in the same period. Proved reserves additions and revisions for the period are determined by Cenovus's independent qualified reserves evaluators, effective December 31, 2016, and for purposes of determining F&D costs, exclude changes resulting from acquisitions, dispositions and production. F&D costs provide an indication of the unit cost of finding and developing new reserves.

Recycle ratio is an approximate measure used to illustrate the value realized from selling a barrel of oil relative to the cost of adding a barrel of oil to reserves. Recycle ratio is defined as the Operating Netback (in $/BOE for the year) divided by the F&D (in $/BOE). Operating Netback is defined as production revenues, excluding realized gains and losses on commodity hedging, less royalties, production and mineral taxes, transportation and production expenses, calculated on a per BOE basis.

Sustaining capital costs per barrel is defined as total oil sands capital investment excluding growth capital divided by total oil sands production capacity. It is used by Management to assess capital efficiency in maintaining oil sands production at capacity.

F&D costs, recycle ratio and sustaining costs are oil and gas metrics. Management uses these metrics to evaluate Cenovus's performance over time. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other issuers and may be misleading when making comparisons. F&D costs, recycle ratio and sustaining costs are historical measures and are not indicators of Cenovus's future performance, which may vary materially.

Barrels of Oil Equivalent

Natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six Mcf to one barrel. 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. Given that the value ratio based on the current price of crude oil compared with natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.

Forward-Looking Information

This news release contains certain forward-looking statements and other information (collectively “forward-looking information”) about Cenovus's current expectations, estimates and projections, made in light of the company's experience and perception of historical trends. Forward-looking information in this document is identified by words such as “anticipate”, “expect”, “estimate”, “plan”, “target”, “position”, “project”, “committed”, “can be”, “pursue”, “capacity”, “potential”, “may”, “on track”, “confidence” or similar expressions and includes suggestions of future outcomes, including statements about: milestones and schedules, including expected timing for oil sands expansion phases and associated expected production capacities; projections for 2017 and future years; forecast operating and financial results; planned capital expenditures; expected future production, including the timing, stability or growth thereof; our ability to preserve our financial resilience and plans and strategies with respect thereto; our expectations regarding growth from our planned oil sands expansions, construction and potential restarts, and future impacts to our oil sands production capacity; achieved and forecast cost reductions, including sustainability and expected impacts thereof; and expected impacts of our hedging program. 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: forecast oil and natural gas prices and other assumptions inherent in Cenovus’s current guidance, available at cenovus.com; projected capital investment levels, flexibility of capital spending plans and associated source of funding; future cost reductions; sustainability of cost reductions; expected condensate prices; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; future use and development of technology; ability to obtain necessary regulatory and partner approvals; successful and timely implementation of capital projects or stages thereof; the company's ability to generate sufficient cash to meet its current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations; and other risks and uncertainties described from time to time in the company's filings with securities regulatory authorities.

2017 guidance, as updated on December 8, 2016, assumes: Brent of US$48.75/bbl; WTI of US$47.25/bbl; WCS of US$31.50/bbl; NYMEX of US$3.00/MMBtu; AECO of $2.60/GJ; Chicago 3-2-1 crack spread of US$11.25/bbl; and an exchange rate of $0.74 US$/C$.

The risk factors and uncertainties that could cause the company's actual results to differ materially include: volatility of and assumptions regarding oil and natural gas prices; the effectiveness of the company's risk management program, including the impact of derivative financial instruments, the success of hedging strategies and the sufficiency of liquidity position; accuracy of cost estimates; commodity prices, currency and interest rates; product supply and demand; market competition, including from alternative energy sources; risks inherent in Cenovus's marketing operations, including credit risks; exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in operation of the company's crude-by-rail terminal, including health, safety and environmental risks; maintaining desirable ratios of debt to adjusted EBITDA and net debt to adjusted EBITDA as well as debt to capitalization and net debt to capitalization; ability to access various sources of debt and equity capital, generally, and on terms acceptable to Cenovus; ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to Cenovus or any of its securities; changes to dividend plans or strategy, including the dividend reinvestment plan; accuracy of reserves, resources and future production estimates; ability to replace and expand oil and gas reserves; ability to maintain relationships with partners and to successfully manage and operate the company's integrated business; reliability of assets, including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; inflationary pressures on operating costs, including labour, natural gas and other energy sources used in oil sands processes; potential failure of products to achieve acceptance in the market; risks associated with fossil fuel industry reputation; 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 Cenovus's business; risks associated with climate change; the timing and costs of well and pipeline construction; ability to secure adequate product transportation, including sufficient pipeline, crude-by-rail, marine or other alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and ability to attract and retain, critical talent; changes in labour relationships; changes in the regulatory framework in any of the locations in which Cenovus operates, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental (including in relation to abandonment, reclamation and remediation costs, levies or liability recovery with respect thereto), 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 Cenovus's business, financial results and consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries of operation; 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.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a discussion of Cenovus's material risk factors, see “Risk Factors” in the company's AIF or Form 40-F for the year ended December 31, 2016, available on SEDAR at sedar.com, EDGAR at sec.gov and the company's website at cenovus.com.

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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. For more information, visit cenovus.com.

Find Cenovus on Facebook, Twitter, LinkedIn, YouTube and Instagram.

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CONSOLIDATED STATEMENTS OF EARNINGS (LOSS) (unaudited)

For the periods ended December 31,
($ millions, except per share amounts)

		Three Months Ended		Twelve Months Ended	
	Notes	**2016**	2015	**2016**	2015
Revenues	1				
Gross Sales		**3,695**	2,955	**12,282**	13,207
Less: Royalties		**53**	31	**148**	143
		3,642	2,924	**12,134**	13,064
Expenses	1				
Purchased Product		**2,075**	1,808	**6,978**	7,374
Transportation and Blending		**541**	534	**1,901**	2,043
Operating		**439**	460	**1,683**	1,839
Production and Mineral Taxes		**3**	2	**12**	18
(Gain) Loss on Risk Management	19	**102**	(213)	**343**	(461)
Depreciation, Depletion and Amortization	7,11	**(71)**	659	**1,498**	2,114
Exploration Expense	7,10	**-**	117	**2**	138
General and Administrative		**101**	109	**326**	335
Finance Costs	3	**124**	123	**492**	482
Interest Income		**(7)**	(8)	**(52)**	(28)
Foreign Exchange (Gain) Loss, Net	4	**140**	204	**(198)**	1,036
Research Costs		**6**	7	**36**	27
(Gain) Loss on Divestiture of Assets	5	**-**	3	**6**	(2,392)
Other (Income) Loss, Net	6	**27**	1	**34**	2
Earnings (Loss) Before Income Tax		**162**	(882)	**(927)**	537
Income Tax Expense (Recovery)	8	**71**	(241)	**(382)**	(81)
Net Earnings (Loss)		**91**	(641)	**(545)**	618
Net Earnings (Loss) Per Share ($)	9				
Basic and Diluted		**0.11**	(0.77)	**(0.65)**	0.75

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (unaudited)

For the periods ended December 31,
($ millions)

		Three Months Ended		Twelve Months Ended	
	Notes	**2016**	2015	**2016**	2015
Net Earnings (Loss)		**91**	(641)	**(545)**	618
Other Comprehensive Income (Loss), Net of Tax	16				
Items That Will Not be Reclassified to Profit or Loss:					
Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits		**6**	15	**(3)**	20
Items That May be Reclassified to Profit or Loss:					
Available for Sale Financial Assets – Change in Fair Value		**-**	6	**(2)**	6
Available for Sale Financial Assets – Reclassified to Profit or Loss		**-**	-	**1**	-
Foreign Currency Translation Adjustment		**99**	124	**(106)**	587
Total Other Comprehensive Income (Loss), Net of Tax		**105**	145	**(110)**	613
Comprehensive Income (Loss)		**196**	(496)	**(655)**	1,231

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED BALANCE SHEETS (unaudited)

As at December 31,
($ millions)

	Notes	**2016**	2015
Assets			
Current Assets			
Cash and Cash Equivalents		**3,720**	4,105
Accounts Receivable and Accrued Revenues		**1,838**	1,251
Income Tax Receivable		**6**	6
Inventories		**1,237**	810
Risk Management	19,20	**21**	301
Total Current Assets		**6,822**	6,473
Exploration and Evaluation Assets	1,10	**1,585**	1,575
Property, Plant and Equipment, Net	1,11	**16,426**	17,335
Risk Management	19,20	**3**	-
Income Tax Receivable		**124**	90
Other Assets		**56**	76
Goodwill	1	**242**	242
Total Assets		**25,258**	25,791
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities		**2,266**	1,702
Income Tax Payable		**112**	133
Risk Management	19,20	**293**	23
Total Current Liabilities		**2,671**	1,858
Long-Term Debt	13	**6,332**	6,525
Risk Management	19,20	**22**	7
Decommissioning Liabilities	14	**1,847**	2,052
Other Liabilities		**211**	142
Deferred Income Taxes		**2,585**	2,816
Total Liabilities		**13,668**	13,400
Shareholders' Equity		**11,590**	12,391
Total Liabilities and Shareholders' Equity		**25,258**	25,791

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (unaudited)

($ millions)

	Share Capital	Paid in Surplus	Retained Earnings	AOCI [1]	**Total**
	(Note 15)			(Note 16)	
As at December 31, 2014	3,889	4,291	1,599	407	10,186
Net Earnings	-	-	618	-	618
Other Comprehensive Income	-	-	-	613	613
Total Comprehensive Income	-	-	618	613	1,231
Common Shares Issued for Cash	1,463	-	-	-	1,463
Common Shares Issued Pursuant to Dividend Reinvestment Plan	182	-	-	-	182
Stock-Based Compensation Expense	-	39	-	-	39
Dividends on Common Shares	-	-	(710)	-	(710)
As at December 31, 2015	5,534	4,330	1,507	1,020	12,391
Net Earnings (Loss)	-	-	(545)	-	(545)
Other Comprehensive Income (Loss)	-	-	-	(110)	(110)
Total Comprehensive Income (Loss)	-	-	(545)	(110)	(655)
Stock-Based Compensation Expense	-	20	-	-	20
Dividends on Common Shares	-	-	(166)	-	(166)
As at December 31, 2016	**5,534**	**4,350**	**796**	**910**	**11,590**

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

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the periods ended December 31,
($ millions)

	Notes	Three Months Ended 2016	Three Months Ended 2015	Twelve Months Ended 2016	Twelve Months Ended 2015
Operating Activities					
Net Earnings (Loss)		**91**	(641)	**(545)**	618
Depreciation, Depletion and Amortization	7,11	**(71)**	659	**1,498**	2,114
Exploration Expense	7,10	**-**	117	**2**	138
Deferred Income Taxes	8	**144**	(139)	**(209)**	(655)
Unrealized (Gain) Loss on Risk Management	19	**114**	26	**554**	195
Unrealized Foreign Exchange (Gain) Loss	4	**152**	219	**(189)**	1,097
(Gain) Loss on Divestiture of Assets	5	**-**	3	**6**	(2,392)
Current Tax on Divestiture of Assets	5	**-**	-	**-**	391
Unwinding of Discount on Decommissioning Liabilities	3,14	**33**	32	**130**	126
Onerous Contract Provisions, Net of Cash Paid		**27**	-	**53**	-
Other Asset Impairments	6	**23**	-	**30**	-
Other		**22**	(1)	**93**	59
Net Change in Other Assets and Liabilities		**(32)**	(26)	**(91)**	(107)
Net Change in Non-Cash Working Capital		**(339)**	73	**(471)**	(110)
Cash From Operating Activities		**164**	322	**861**	1,474
Investing Activities					
Capital Expenditures – Exploration and Evaluation Assets	10	**(11)**	(21)	**(67)**	(138)
Capital Expenditures – Property, Plant and Equipment	11	**(248)**	(406)	**(967)**	(1,576)
Acquisition	12	**-**	(4)	**-**	(84)
Proceeds From Divestiture of Assets	5	**-**	(1)	**8**	3,344
Current Tax on Divestiture of Assets	5	**-**	-	**-**	(391)
Net Change in Investments and Other		**(1)**	3	**(1)**	3
Net Change in Non-Cash Working Capital		**16**	(40)	**(52)**	(270)
Cash From (Used in) Investing Activities		**(244)**	(469)	**(1,079)**	888
Net Cash Provided (Used) Before Financing Activities		**(80)**	(147)	**(218)**	2,362
Financing Activities					
Net Issuance (Repayment) of Short-Term Borrowings		**-**	(6)	**-**	(25)
Common Shares Issued, Net of Issuance Costs		**-**	-	**-**	1,449
Dividends Paid on Common Shares	9	**(42)**	(132)	**(166)**	(528)
Other		**(1)**	-	**(2)**	(2)
Cash From (Used in) Financing Activities		**(43)**	(138)	**(168)**	894
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(7)**	(11)	**1**	(34)
Increase (Decrease) in Cash and Cash Equivalents		**(130)**	(296)	**(385)**	3,222
Cash and Cash Equivalents, Beginning of Period		**3,850**	4,401	**4,105**	883
Cash and Cash Equivalents, End of Period		**3,720**	4,105	**3,720**	4,105

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 developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with marketing activities and refining operations in the United States ("U.S.").

Cenovus is incorporated under the *Canada Business Corporations Act* and its shares are listed 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 interim 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 margin. The Company's reportable segments are:

- **Oil Sands,** which includes the development and production of bitumen and natural gas in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.
- **Conventional,** which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake, the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.
- **Refining and Marketing,** which is responsible for transporting, selling and refining crude oil into petroleum and chemical products. Cenovus jointly owns two refineries in the U.S. with the operator Phillips 66, an unrelated U.S. public company. In addition, Cenovus owns and operates a crude-by-rail terminal in Alberta. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification. The marketing of crude oil and natural gas sourced from Canada, including physical product sales that settle in the U.S., is considered to be undertaken by a Canadian business. U.S. sourced crude oil and natural gas purchases and sales are attributed to the U.S.
- **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, financing activities and research costs. 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 Corporate and Eliminations segment is attributed to Canada, with the exception of unrealized risk management gains and losses, which have been attributed to the country in which the transacting entity resides.

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,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**957**	651	**369**	351	**2,477**	2,030
Less: Royalties	**2**	3	**51**	28	**-**	-
	955	648	**318**	323	**2,477**	2,030
Expenses						
Purchased Product	**-**	-	**-**	-	**2,181**	1,883
Transportation and Blending	**493**	478	**50**	58	**-**	-
Operating	**142**	129	**113**	130	**185**	203
Production and Mineral Taxes	**-**	-	**3**	2	**-**	-
(Gain) Loss on Risk Management	**(14)**	(152)	**(1)**	(71)	**3**	(16)
Operating Margin [1]	**334**	193	**153**	204	**108**	(40)
Depreciation, Depletion and Amortization	**170**	189	**(310)**	403	**54**	51
Exploration Expense	**-**	67	**-**	50	**-**	-
Segment Income (Loss)	**164**	(63)	**463**	(249)	**54**	(91)

(1) *Previously labelled Operating Cash Flow.*

	Corporate and Eliminations		Consolidated	
For the three months ended December 31,	**2016**	2015	**2016**	2015
Revenues				
Gross Sales	**(108)**	(77)	**3,695**	2,955
Less: Royalties	**-**	-	**53**	31
	(108)	(77)	**3,642**	2,924
Expenses				
Purchased Product	**(106)**	(75)	**2,075**	1,808
Transportation and Blending	**(2)**	(2)	**541**	534
Operating	**(1)**	(2)	**439**	460
Production and Mineral Taxes	**-**	-	**3**	2
(Gain) Loss on Risk Management	**114**	26	**102**	(213)
Depreciation, Depletion and Amortization	**15**	16	**(71)**	659
Exploration Expense	**-**	-	**-**	117
Segment Income (Loss)	**(128)**	(40)	**553**	(443)
General and Administrative	**101**	109	**101**	109
Finance Costs	**124**	123	**124**	123
Interest Income	**(7)**	(8)	**(7)**	(8)
Foreign Exchange (Gain) Loss, Net	**140**	204	**140**	204
Research Costs	**6**	7	**6**	7
(Gain) Loss on Divestiture of Assets	**-**	3	**-**	3
Other (Income) Loss, Net	**27**	1	**27**	1
	391	439	**391**	439
Earnings (Loss) Before Income Tax			**162**	(882)
Income Tax Expense (Recovery)			**71**	(241)
Net Earnings (Loss)			**91**	(641)

B) Financial Results by Upstream Product

	Crude Oil [1]					
	Oil Sands		Conventional		Total	
For the three months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**951**	644	**266**	239	**1,217**	883
Less: Royalties	**2**	3	**45**	25	**47**	28
	949	641	**221**	214	**1,170**	855
Expenses						
Transportation and Blending	**492**	478	**46**	53	**538**	531
Operating	**138**	124	**74**	84	**212**	208
Production and Mineral Taxes	**-**	-	**3**	2	**3**	2
(Gain) Loss on Risk Management	**(14)**	(151)	**(2)**	(57)	**(16)**	(208)
Operating Margin [2]	**333**	190	**100**	132	**433**	322

	Natural Gas					
	Oil Sands		Conventional		Total	
For the three months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**5**	5	**100**	104	**105**	109
Less: Royalties	**-**	-	**6**	3	**6**	3
	5	5	**94**	101	**99**	106
Expenses						
Transportation and Blending	**1**	-	**4**	5	**5**	5
Operating	**4**	3	**39**	44	**43**	47
Production and Mineral Taxes	**-**	-	**-**	-	**-**	-
(Gain) Loss on Risk Management	**-**	(1)	**1**	(14)	**1**	(15)
Operating Margin [2]	**-**	3	**50**	66	**50**	69

	Other					
	Oil Sands		Conventional		Total	
For the three months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**1**	2	**3**	8	**4**	10
Less: Royalties	**-**	-	**-**	-	**-**	-
	1	2	**3**	8	**4**	10
Expenses						
Transportation and Blending	**-**	-	**-**	-	**-**	-
Operating	**-**	2	**-**	2	**-**	4
Production and Mineral Taxes	**-**	-	**-**	-	**-**	-
(Gain) Loss on Risk Management	**-**	-	**-**	-	**-**	-
Operating Margin [2]	**1**	-	**3**	6	**4**	6

	Total Upstream					
	Oil Sands		Conventional		Total	
For the three months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**957**	651	**369**	351	**1,326**	1,002
Less: Royalties	**2**	3	**51**	28	**53**	31
	955	648	**318**	323	**1,273**	971
Expenses						
Transportation and Blending	**493**	478	**50**	58	**543**	536
Operating	**142**	129	**113**	130	**255**	259
Production and Mineral Taxes	**-**	-	**3**	2	**3**	2
(Gain) Loss on Risk Management	**(14)**	(152)	**(1)**	(71)	**(15)**	(223)
Operating Margin [2]	**334**	193	**153**	204	**487**	397

(1) Includes NGLs.
(2) Previously labelled Operating Cash Flow.

C) Results of Operations – Segment and Operational Information

	Oil Sands		Conventional		Refining and Marketing	
For the twelve months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**2,929**	3,030	**1,267**	1,709	**8,439**	8,805
Less: Royalties	**9**	29	**139**	114	**-**	-
	2,920	3,001	**1,128**	1,595	**8,439**	8,805
Expenses						
Purchased Product	**-**	-	**-**	-	**7,325**	7,709
Transportation and Blending	**1,721**	1,815	**186**	230	**-**	-
Operating	**501**	531	**444**	561	**742**	754
Production and Mineral Taxes	**-**	-	**12**	18	**-**	-
(Gain) Loss on Risk Management	**(179)**	(404)	**(58)**	(209)	**26**	(43)
Operating Margin [(1)]	**877**	1,059	**544**	995	**346**	385
Depreciation, Depletion and Amortization	**655**	697	**567**	1,148	**211**	191
Exploration Expense	**2**	67	**-**	71	**-**	-
Segment Income (Loss)	**220**	295	**(23)**	(224)	**135**	194

(1) Previously labelled Operating Cash Flow.

	Corporate and Eliminations		Consolidated	
For the twelve months ended December 31,	**2016**	2015	**2016**	2015
Revenues				
Gross Sales	**(353)**	(337)	**12,282**	13,207
Less: Royalties	**-**	-	**148**	143
	(353)	(337)	**12,134**	13,064
Expenses				
Purchased Product	**(347)**	(335)	**6,978**	7,374
Transportation and Blending	**(6)**	(2)	**1,901**	2,043
Operating	**(4)**	(7)	**1,683**	1,839
Production and Mineral Taxes	**-**	-	**12**	18
(Gain) Loss on Risk Management	**554**	195	**343**	(461)
Depreciation, Depletion and Amortization	**65**	78	**1,498**	2,114
Exploration Expense	**-**	-	**2**	138
Segment Income (Loss)	**(615)**	(266)	**(283)**	(1)
General and Administrative	**326**	335	**326**	335
Finance Costs	**492**	482	**492**	482
Interest Income	**(52)**	(28)	**(52)**	(28)
Foreign Exchange (Gain) Loss, Net	**(198)**	1,036	**(198)**	1,036
Research Costs	**36**	27	**36**	27
(Gain) Loss on Divestiture of Assets	**6**	(2,392)	**6**	(2,392)
Other (Income) Loss, Net	**34**	2	**34**	2
	644	(538)	**644**	(538)
Earnings (Loss) Before Income Tax			**(927)**	537
Income Tax Expense (Recovery)			**(382)**	(81)
Net Earnings (Loss)			**(545)**	618

D) Financial Results by Upstream Product

	Crude Oil (1)					
	Oil Sands		**Conventional**		**Total**	
For the twelve months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**2,911**	3,000	**936**	1,239	**3,847**	4,239
Less: Royalties	**9**	29	**125**	103	**134**	132
	2,902	2,971	**811**	1,136	**3,713**	4,107
Expenses						
Transportation and Blending	**1,720**	1,814	**170**	213	**1,890**	2,027
Operating	**486**	511	**287**	381	**773**	892
Production and Mineral Taxes	**-**	-	**12**	16	**12**	16
(Gain) Loss on Risk Management	**(179)**	(400)	**(60)**	(157)	**(239)**	(557)
Operating Margin (2)	**875**	1,046	**402**	683	**1,277**	1,729

	Natural Gas					
	Oil Sands		**Conventional**		**Total**	
For the twelve months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**16**	22	**321**	450	**337**	472
Less: Royalties	**-**	-	**14**	11	**14**	11
	16	22	**307**	439	**323**	461
Expenses						
Transportation and Blending	**1**	1	**16**	17	**17**	18
Operating	**11**	15	**152**	175	**163**	190
Production and Mineral Taxes	**-**	-	**-**	2	**-**	2
(Gain) Loss on Risk Management	**-**	(4)	**2**	(52)	**2**	(56)
Operating Margin (2)	**4**	10	**137**	297	**141**	307

	Other					
	Oil Sands		**Conventional**		**Total**	
For the twelve months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**2**	8	**10**	20	**12**	28
Less: Royalties	**-**	-	**-**	-	**-**	-
	2	8	**10**	20	**12**	28
Expenses						
Transportation and Blending	**-**	-	**-**	-	**-**	-
Operating	**4**	5	**5**	5	**9**	10
Production and Mineral Taxes	**-**	-	**-**	-	**-**	-
(Gain) Loss on Risk Management	**-**	-	**-**	-	**-**	-
Operating Margin (2)	**(2)**	3	**5**	15	**3**	18

	Total Upstream					
	Oil Sands		**Conventional**		**Total**	
For the twelve months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**2,929**	3,030	**1,267**	1,709	**4,196**	4,739
Less: Royalties	**9**	29	**139**	114	**148**	143
	2,920	3,001	**1,128**	1,595	**4,048**	4,596
Expenses						
Transportation and Blending	**1,721**	1,815	**186**	230	**1,907**	2,045
Operating	**501**	531	**444**	561	**945**	1,092
Production and Mineral Taxes	**-**	-	**12**	18	**12**	18
(Gain) Loss on Risk Management	**(179)**	(404)	**(58)**	(209)	**(237)**	(613)
Operating Margin (2)	**877**	1,059	**544**	995	**1,421**	2,054

(1) *Includes NGLs.*
(2) *Previously labelled Operating Cash Flow.*

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

	E&E (1)		PP&E (2)	
As at December 31,	**2016**	2015	**2016**	2015
Oil Sands	**1,564**	1,560	**8,798**	8,907
Conventional	**21**	15	**3,080**	3,720
Refining and Marketing	**-**	-	**4,273**	4,398
Corporate and Eliminations	**-**	-	**275**	310
Consolidated	**1,585**	1,575	**16,426**	17,335

	Goodwill		Total Assets	
As at December 31,	**2016**	2015	**2016**	2015
Oil Sands	**242**	242	**11,112**	11,069
Conventional	**-**	-	**3,196**	3,830
Refining and Marketing	**-**	-	**6,613**	5,844
Corporate and Eliminations	**-**	-	**4,337**	5,048
Consolidated	**242**	242	**25,258**	25,791

(1) Exploration and Evaluation ("E&E") assets.
(2) Property, Plant and Equipment ("PP&E").

F) Geographical Information

	Revenues			
	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2016**	2015	**2016**	2015
Canada	**1,966**	1,367	**6,106**	6,264
United States	**1,676**	1,557	**6,028**	6,800
Consolidated	**3,642**	2,924	**12,134**	13,064

	Non-Current Assets (3)	
As at December 31,	**2016**	2015
Canada	**14,130**	14,921
United States	**4,179**	4,307
Consolidated	**18,309**	19,228

(3) Includes E&E, PP&E, goodwill and other assets.

G) Capital Expenditures (4)

	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2016**	2015	**2016**	2015
Capital				
Oil Sands	**128**	239	**604**	1,185
Conventional	**57**	87	**171**	244
Refining and Marketing	**65**	89	**220**	248
Corporate	**9**	13	**31**	37
Capital Investment	**259**	428	**1,026**	1,714
Acquisition Capital				
Oil Sands	**-**	3	**11**	3
Conventional	**-**	-	**-**	1
Refining and Marketing	**-**	-	**-**	83
Total Capital Expenditures	**259**	431	**1,037**	1,801

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

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

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

These interim Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including International Accounting Standard 34, "*Interim Financial Reporting*" ("IAS 34"), and have been prepared following the same accounting policies and methods of computation as the annual Consolidated Financial Statements for the year ended December 31, 2015, except 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. 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, 2015, which have been prepared in accordance with IFRS as issued by the IASB.

These interim Consolidated Financial Statements were approved by the Audit Committee effective February 15, 2017.

3. FINANCE COSTS

	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2016**	2015	**2016**	2015
Interest Expense – Short-Term Borrowings and Long-Term Debt	**86**	85	**341**	328
Unwinding of Discount on Decommissioning Liabilities (Note 14)	**33**	32	**130**	126
Other	**5**	6	**21**	28
	124	123	**492**	482

4. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2016**	2015	**2016**	2015
Unrealized Foreign Exchange (Gain) Loss on Translation of:				
U.S. Dollar Debt Issued From Canada	**147**	212	**(196)**	1,064
Other	**5**	7	**7**	33
Unrealized Foreign Exchange (Gain) Loss	**152**	219	**(189)**	1,097
Realized Foreign Exchange (Gain) Loss	**(12)**	(15)	**(9)**	(61)
	140	204	**(198)**	1,036

5. DIVESTITURES

In the third quarter of 2016, the Company completed the sale of land to an unrelated third party for cash proceeds of $8 million, resulting in a loss of $5 million. In the second quarter of 2016, the Company sold equipment at a loss of $1 million. These assets, related liabilities and results of operations were reported in the Conventional segment.

In the third quarter of 2015, the Company completed the sale of Heritage Royalty Limited Partnership ("HRP"), a wholly-owned subsidiary, to a third party for gross cash proceeds of $3.3 billion, resulting in a gain of $2.4 billion. HRP was a royalty business consisting of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. These assets, related liabilities and results of operations were reported in the Conventional segment.

The divestiture gave rise to a taxable gain for which the Company recognized a current tax expense of $391 million. The majority of HRP's assets had been acquired at a nominal cost and, as such, had minimal benefit from tax depreciation in prior years. For this reason, the current tax expense associated with the divestiture was specifically identifiable; therefore, it has been classified as an investing activity in the Consolidated Statements of Cash Flows.

In the first quarter of 2015, the Company divested an office building, recording a gain of $16 million.

6. OTHER (INCOME) LOSS, NET

As at December 31, 2016, due to the Government of Canada's decision to reject the Northern Gateway Pipeline project, the Company has written off $23 million of capitalized costs associated with its funding support unit in Northern Gateway Pipeline. In addition, $7 million of expected costs associated with termination have been recorded.

In 2016, $7 million (2015 – $nil) of certain investments in private equity companies were written off.

7. IMPAIRMENT CHARGES AND REVERSALS

A) Cash-Generating Unit ("CGU") Net Impairments

The review of the Company's PP&E and E&E assets for indicators of impairment as at December 31, 2016 provided evidence that a portion of the impairment losses previously recorded should be reversed.

2016 Net Upstream Impairments

As at December 31, 2016, the recoverable value of the Northern Alberta CGU was estimated to be $1.1 billion. Earlier in 2016 and 2015, impairment losses of $380 million and $184 million, respectively, were recorded primarily due to a decline in long-term heavy crude oil prices and a slowing of the development plan. In the fourth quarter of 2016, the Company reversed $400 million of impairment losses, net of the depreciation, depletion and amortization ("DD&A") that would have been recorded had no impairments been recorded. The reversal arose due to the increase in the CGU's estimated recoverable amount caused by an average reduction in expected future operating costs of five percent and lower future development costs, partially offset by a decline in estimated reserves. The impairment losses and subsequent reversal were recorded as DD&A in the Conventional segment. The Northern Alberta CGU includes the Pelican Lake and Elk Point producing assets and other emerging assets in the exploration and evaluation stage.

As at December 31, 2016, the recoverable amount of the Suffield CGU was estimated to be $548 million. Earlier in 2016, an impairment loss of $65 million was recognized due to lower long-term forward natural gas and heavy crude oil prices. In the fourth quarter of 2016, the Company reversed the full amount of the impairment losses, net of the DD&A that would have been recorded had no impairment been recorded ($62 million). The reversal arose due to a decline in expected future royalties increasing the estimated recoverable amount of the CGU. The impairment loss and the subsequent reversal were recorded as DD&A in the Conventional segment. The Suffield CGU includes production of natural gas and heavy crude oil in Alberta on the Canadian Forces Base.

For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates. There were no goodwill impairments for the twelve months ended December 31, 2016.

Key Assumptions

The recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs of disposal ("FVLCOD") or an evaluation of comparable asset transactions. The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, prepared by Cenovus's independent qualified reserves evaluators ("IQREs") (Level 3). Key assumptions in the determination of future cash flows from reserves include crude oil and natural gas prices, costs to develop and the discount rate. All reserves have been evaluated as at December 31, 2016 by the IQREs.

Crude Oil and Natural Gas Prices

The forward prices as at December 31, 2016, used to determine future cash flows from crude oil and natural gas reserves were:

	2017	2018	2019	2020	2021	Average Annual Increase Thereafter
WTI (US$/barrel) (1)	55.00	58.70	62.40	69.00	75.80	2.0%
WCS (C$/barrel) (2)	53.70	58.20	61.90	66.50	71.00	2.0%
AECO (C$/Mcf) (3) (4)	3.40	3.15	3.30	3.60	3.90	2.2%

(1) West Texas Intermediate ("WTI") crude oil.
(2) Western Canadian Select ("WCS") crude oil blend.
(3) Alberta Energy Company ("AECO") natural gas.
(4) Assumes gas heating value of one million British Thermal Units per thousand cubic feet.

Discount and Inflation Rates

Evaluations of discounted future cash flows are initiated using the discount rate of 10 percent and inflation is estimated at two percent, which is common industry practice and used by Cenovus's IQREs in preparing the reserves report. Based on the individual characteristics of the CGU, other economic and operating factors are also considered, which may increase or decrease the implied discount rate.

Sensitivities

The estimated recoverable value of the Northern Alberta CGU is sensitive to discount rate and forward price estimates over the life of the reserves. Changes to these assumptions, assuming all other variables remained constant, would have had the following impact on the 2016 net impairment of the Northern Alberta CGU:

	One Percent Increase in the Discount Rate	One Percent Decrease in the Discount Rate (1)	Five Percent Increase in the Forward Price Estimates (1)	Five Percent Decrease in the Forward Price Estimates
Increase (Decrease) to Net Impairment of PP&E	**132**	**(106)**	**(106)**	**270**

(1) *The $106 million represents the remaining impairment loss that could be reversed as at December 31, 2016.*

2015 Impairments

As at December 31, 2015, the Company determined that the carrying amount of the Northern Alberta CGU exceeded its recoverable amount, resulting in an impairment loss of $184 million. The impairment was recorded as additional DD&A in the Conventional segment. Future cash flows for the CGU declined due to lower forward crude oil prices, a decline in reserves estimates and a slowing down of the development plan. This was partially offset by lower future development and operating costs.

The recoverable amount was determined using FVLCOD. The fair value of producing properties was calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, prepared by Cenovus's IQREs (Level 3). Future cash flows were estimated using a two percent inflation rate and discounted using a rate of 10 percent. As at December 31, 2015, the recoverable amount of the Northern Alberta CGU was estimated to be approximately $1.5 billion.

There were no goodwill impairments for the twelve months ended December 31, 2015.

B) Asset Impairments

Exploration and Evaluation Assets

In 2016, $2 million of previously capitalized E&E costs were deemed not to be technically feasible and commercially viable. This impairment loss was recorded as exploration expense in the Oil Sands segment.

In 2015, $138 million of previously capitalized E&E costs were deemed not to be technically feasible and commercially viable, and were recorded as exploration expense. This impairment loss included $67 million and $71 million within the Oil Sands and Conventional segments, respectively.

Property, Plant and Equipment, Net

In the fourth quarter of 2016, the Company recorded an impairment loss of $20 million primarily related to equipment that was written down to its recoverable amount. This impairment was recorded as additional DD&A in the Conventional segment.

In the third quarter of 2016, the Company recorded an impairment loss of $16 million related to preliminary engineering costs associated with a project that was cancelled and equipment that was written down to its recoverable amount. This impairment loss was recorded as additional DD&A in the Oil Sands segment. In the second quarter of 2016, $4 million of leasehold improvements were written off. This impairment loss was recorded as additional DD&A in the Corporate and Eliminations segment.

In 2015, the Company impaired a sulphur recovery facility for $16 million, which was recorded as additional DD&A in the Oil Sands segment. The Company did not have future plans for the assets and did not believe it would recover the carrying amount through a sale.

8. INCOME TAXES

The provision for income taxes is:

	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2016**	2015	**2016**	2015
Current Tax				
Canada	**(73)**	(100)	**(174)**	586
United States	**-**	(2)	**1**	(12)
Total Current Tax Expense (Recovery)	**(73)**	(102)	**(173)**	574
Deferred Tax Expense (Recovery)	**144**	(139)	**(209)**	(655)
	71	(241)	**(382)**	(81)

In 2016, the Company recorded a current tax recovery due to the carryback of losses for income tax purposes and prior year adjustments.

In 2015, the Company recorded a deferred tax recovery of $415 million arising from an adjustment to the tax basis of the refining assets. The increase in tax basis was a result of the Company's partner recognizing a taxable gain on its interest in WRB Refining LP ("WRB") which, due to an election filed with the U.S. tax authorities, was added to the tax basis of WRB's assets. The Government of Alberta enacted a two percent increase in the corporate income tax rate effective July 1, 2015, increasing the statutory tax rate for the year to 26.1 percent. As a result, the Company's deferred income tax liability increased by $161 million for the year ended December 31, 2015.

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

For the twelve months ended December 31,	**2016**	2015
Earnings (Loss) Before Income Tax	**(927)**	537
Canadian Statutory Rate	**27.0%**	26.1%
Expected Income Tax (Recovery)	**(250)**	140
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	**(46)**	(41)
Non-Deductible Stock-Based Compensation	**5**	7
Non-Taxable Capital (Gains) Losses	**(26)**	137
Unrecognized Capital (Gains) Losses Arising From Unrealized Foreign Exchange	**(26)**	135
Adjustments Arising From Prior Year Tax Filings	**(46)**	(55)
Derecognition (Recognition) of Capital Losses	**-**	(149)
(Recognition) of U.S. Tax Basis	**-**	(415)
Change in Statutory Rate	**-**	161
Other	**7**	(1)
Total Tax (Recovery)	**(382)**	(81)
Effective Tax Rate	**41.2%**	(15.1)%

9. PER SHARE AMOUNTS

A) Net Earnings (Loss) Per Share

	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2016**	2015	**2016**	2015
Net Earnings (Loss) – Basic and Diluted ($ millions)	**91**	(641)	**(545)**	618
Weighted Average Number of Shares – Basic and Diluted (millions)	**833.3**	833.3	**833.3**	818.7
Net Earnings (Loss) Per Share – Basic and Diluted ($)	**0.11**	(0.77)	**(0.65)**	0.75

B) Dividends Per Share

For the twelve months ended December 31, 2016, the Company paid dividends of $166 million or $0.20 per share, all of which were paid in cash (twelve months ended December 31, 2015 – $710 million or $0.8524 per share, including cash dividends of $528 million).

10. EXPLORATION AND EVALUATION ASSETS

	Total
As at December 31, 2015	1,575
Additions	67
Transfers to PP&E (Note 11)	(49)
Exploration Expense (Note 7)	(2)
Change in Decommissioning Liabilities	(6)
As at December 31, 2016	**1,585**

11. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	Other Upstream	Refining Equipment	Other [(1)]	Total
COST					
As at December 31, 2015	31,481	331	5,206	1,037	38,055
Additions	717	2	213	38	970
Transfers From E&E Assets (Note 10)	49	-	-	-	49
Change in Decommissioning Liabilities	(267)	-	(8)	-	(275)
Exchange Rate Movements and Other	(16)	-	(152)	(1)	(169)
Divestitures (Note 5)	(23)	-	-	-	(23)
As at December 31, 2016	**31,941**	**333**	**5,259**	**1,074**	**38,607**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at December 31, 2015	18,908	277	896	639	20,720
DD&A	1,173	31	205	66	1,475
Impairment Losses (Note 7)	481	-	-	4	485
Reversal of Impairment Losses (Note 7)	(462)	-	-	-	(462)
Exchange Rate Movements and Other	(4)	-	(25)	-	(29)
Divestitures (Note 5)	(8)	-	-	-	(8)
As at December 31, 2016	**20,088**	**308**	**1,076**	**709**	**22,181**
CARRYING VALUE					
As at December 31, 2015	12,573	54	4,310	398	17,335
As at December 31, 2016	**11,853**	**25**	**4,183**	**365**	**16,426**

(1) *Includes crude-by-rail terminal, office furniture, fixtures, leasehold improvements, information technology and aircraft.*

12. ACQUISITION

In 2015, the Company completed the acquisition of a crude-by-rail terminal for cash consideration of $75 million, plus adjustments. The transaction was accounted for using the acquisition method of accounting. In connection with the acquisition, the Company assumed an associated decommissioning liability of $4 million, working capital of $1 million and net transportation commitments of $92 million. Transaction costs associated with the acquisition were expensed. These assets, related liabilities and results of operations are reported in the Refining and Marketing segment.

13. LONG-TERM DEBT

As at December 31,	US$ Principal	2016	2015
Revolving Term Debt [(1)]	**-**	**-**	-
U.S. Dollar Denominated Unsecured Notes	**4,750**	**6,378**	6,574
Total Debt Principal		**6,378**	6,574
Debt Discounts and Transaction Costs		**(46)**	(49)
		6,332	6,525

(1) *Revolving term debt may include Bankers' Acceptances, London Interbank Offered Rate based loans, prime rate loans and U.S. base rate loans.*

On February 24, 2016, Cenovus filed a base shelf prospectus. The base shelf prospectus allows the Company to offer, from time to time, up to US$5.0 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere where permitted by law. The base shelf prospectus will expire in March 2018. As at December 31, 2016, no issuances have been made under the US$5.0 billion base shelf prospectus.

On April 22, 2016, the Company renegotiated the maturity date of the $1.0 billion tranche of its committed credit facility from November 30, 2017 to April 30, 2019. As at December 31, 2016, Cenovus had $4.0 billion available on its committed credit facility.

As at December 31, 2016, the Company is in compliance with all of the terms of its debt agreements.

14. DECOMMISSIONING LIABILITIES

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

	Total
As at December 31, 2015	2,052
Liabilities Incurred	11
Liabilities Settled	(51)
Liabilities Divested	(1)
Change in Estimated Future Cash Flows	(423)
Change in Discount Rate	131
Unwinding of Discount on Decommissioning Liabilities	130
Foreign Currency Translation	(2)
As at December 31, 2016	**1,847**

The undiscounted amount of estimated future cash flows required to settle the obligation has been discounted using a credit-adjusted risk-free rate of 5.9 percent as at December 31, 2016 (December 31, 2015 – 6.4 percent).

15. SHARE CAPITAL

A) Authorized

Cenovus is authorized to issue an unlimited number of common shares, and first and second preferred shares not exceeding, in aggregate, 20 percent of the number of issued and outstanding common shares. The first and second preferred shares may be issued in one or more series with rights and conditions to be determined by the Company's Board of Directors prior to issuance and subject to the Company's articles.

B) Issued and Outstanding

As at December 31, 2016	**Number of Common Shares** (thousands)	**Amount**
Outstanding, Beginning of Year and End of Year	**833,290**	**5,534**

There were no preferred shares outstanding as at December 31, 2016 (December 31, 2015 – nil).

As at December 31, 2016, there were 12 million (December 31, 2015 – 12 million) common shares available for future issuance under the stock option plan.

16. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Defined Benefit Plan	Foreign Currency Translation	Available for Sale Financial Assets	Total
As at December 31, 2014	(30)	427	10	407
Other Comprehensive Income (Loss), Before Tax	28	587	8	623
Income Tax	(8)	-	(2)	(10)
As at December 31, 2015	(10)	1,014	16	1,020
Other Comprehensive Income (Loss), Before Tax	(4)	(106)	(4)	(114)
Income Tax	1	-	3	4
As at December 31, 2016	**(13)**	**908**	**15**	**910**

17. STOCK-BASED COMPENSATION PLANS

Cenovus has a number of stock-based compensation plans which include stock options with associated net settlement rights ("NSRs"), stock options with associated tandem stock appreciation rights ("TSARs"), performance share units ("PSUs"), restricted share units ("RSUs") and deferred share units ("DSUs"). The following table summarizes information related to Cenovus's stock-based compensation plans:

As at December 31, 2016	Units Outstanding (thousands)	Units Exercisable (thousands)
NSRs	**41,644**	**30,006**
TSARs	**3,373**	**3,373**
PSUs	**6,157**	**-**
RSUs	**3,790**	**-**
DSUs	**1,598**	**1,598**

For the twelve months ended December 31, 2016	Units Granted (thousands)	Units Vested and Paid Out (thousands)
NSRs	**3,646**	**-**
PSUs	**2,345**	**979**
RSUs	**1,718**	**32**
DSUs	**103**	**10**

The weighted average exercise price of NSRs and TSARs as at December 31, 2016 was $30.57 and $26.66, respectively.

The following table summarizes the stock-based compensation expense (recovery) recorded for all plans:

	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2016**	2015	**2016**	2015
NSRs	**3**	7	**15**	27
TSARs	**(1)**	(1)	**(1)**	(5)
PSUs	**6**	(6)	**13**	(13)
RSUs	**5**	1	**13**	6
DSUs	**3**	(4)	**7**	(5)
Stock-Based Compensation Expense (Recovery)	**16**	(3)	**47**	10
Stock-Based Compensation Costs Capitalized	**4**	-	**12**	6
Total Stock-Based Compensation	**20**	(3)	**59**	16

18. CAPITAL STRUCTURE

Cenovus's capital structure objectives and targets have remained unchanged from previous periods. Cenovus's capital structure consists of Shareholders' Equity plus Debt. Debt is defined as short-term borrowings, and the current and long-term portions of long-term debt. Net debt includes the Company's short-term borrowings, and the current and long-term portions of long-term debt, net of cash and cash equivalents. 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.

Over the long term, Cenovus targets a Debt to Capitalization ratio of between 30 and 40 percent and a Debt to Adjusted EBITDA ratio of between 1.0 and 2.0 times. At different points within the economic cycle, Cenovus expects these ratios may periodically be outside of the target range.

A) Debt to Capitalization and Net Debt to Capitalization

As at December 31,	**2016**	2015
Debt	**6,332**	6,525
Shareholders' Equity	**11,590**	12,391
	17,922	18,916
Debt to Capitalization	**35%**	34%
Debt	**6,332**	6,525
Add (Deduct):		
Cash and Cash Equivalents	**(3,720)**	(4,105)
Net Debt	**2,612**	2,420
Shareholders' Equity	**11,590**	12,391
	14,202	14,811
Net Debt to Capitalization	**18%**	16%

B) Debt to Adjusted EBITDA and Net Debt to Adjusted EBITDA

As at December 31,	**2016**	2015
Debt	**6,332**	6,525
Net Debt	**2,612**	2,420
Net Earnings (Loss)	**(545)**	618
Add (Deduct):		
Finance Costs	**492**	482
Interest Income	**(52)**	(28)
Income Tax Expense (Recovery)	**(382)**	(81)
DD&A	**1,498**	2,114
E&E Impairment	**2**	138
Unrealized (Gain) Loss on Risk Management	**554**	195
Foreign Exchange (Gain) Loss, Net	**(198)**	1,036
(Gain) Loss on Divestitures of Assets	**6**	(2,392)
Other (Income) Loss, Net	**34**	2
Adjusted EBITDA (1)	**1,409**	2,084
Debt to Adjusted EBITDA	**4.5x**	3.1x
Net Debt to Adjusted EBITDA	**1.9x**	1.2x

(1) *Calculated on a trailing twelve-month basis.*

Cenovus will maintain a high level of capital discipline and manage its capital structure to help ensure sufficient liquidity through all stages of the economic cycle. To manage its capital structure, Cenovus may, among other actions, 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 facility or repay existing debt.

Effective April 22, 2016, the Company extended the maturity date of the $1.0 billion tranche of the committed credit facility from November 30, 2017 to April 30, 2019. As at December 31, 2016, Cenovus had $4.0 billion available on its committed credit facility. In addition, Cenovus has in place a US$5.0 billion base shelf prospectus, the availability of which is dependent on market conditions.

Under the committed credit facility, the Company is required to maintain a debt to capitalization ratio, as defined in the agreement, not to exceed 65 percent. The Company is well below this limit.

As at December 31, 2016, Cenovus is in compliance with all of the terms of its debt agreements.

19. FINANCIAL INSTRUMENTS

Cenovus's financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, risk management assets and liabilities, available for sale financial assets, 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 Non-Derivative Financial Instruments

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 these instruments.

The fair values of long-term receivables approximate their carrying amount due to the specific non-tradeable nature of these instruments.

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, 2016, the carrying value of Cenovus's long-term debt was $6,332 million and the fair value was $6,539 million (December 31, 2015 carrying value – $6,525 million, fair value – $6,050 million).

Available for sale financial assets comprise private equity investments. These assets are carried at fair value on the Consolidated Balance Sheets in other assets. Fair value is determined based on recent private placement transactions (Level 3) when available. The following table provides a reconciliation of changes in the fair value of available for sale financial assets:

	Total
Fair Value, as at December 31, 2015	**42**
Change in Fair Value (1)	**(4)**
Impairment Losses (2)	**(3)**
Fair Value, as at December 31, 2016	**35**

(1) Changes in fair value on available for sale financial assets are recorded in other comprehensive income.
(2) Impairment losses on available for sale financial assets are reclassified from other comprehensive income to profit or loss.

B) Fair Value of Risk Management Assets and Liabilities

The Company's risk management assets and liabilities consist of crude oil, condensate, power purchase contracts and interest rate swaps. Crude oil, condensate and, if entered, 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 fair value of interest rate swaps are calculated using external valuation models which incorporate observable market data, including interest rate yield curves (Level 2).

Summary of Unrealized Risk Management Positions

	2016			2015		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Commodity Prices						
Crude Oil	**21**	**307**	**(286)**	301	15	286
Power	**-**	**-**	**-**	-	13	(13)
	21	**307**	**(286)**	301	28	273
Interest Rate	**3**	**8**	**(5)**	-	2	(2)
Total Fair Value	**24**	**315**	**(291)**	301	30	271

The following table presents the Company's fair value hierarchy for risk management assets and liabilities carried at fair value:

As at December 31,	**2016**	2015
Level 2 – Prices Sourced From Observable Data or Market Corroboration	**(291)**	284
Level 3 – Prices Determined From Unobservable Inputs	**-**	(13)
	(291)	271

Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data. Prices determined from unobservable inputs refers to the fair value of contracts valued using data that is both unobservable and significant to the overall fair value measurement.

The following table provides a reconciliation of changes in the fair value of Cenovus's risk management assets and liabilities from January 1 to December 31:

	2016	2015
Fair Value of Contracts, Beginning of Year	**271**	462
Fair Value of Contracts Realized During the Year [(1)]	**(211)**	(656)
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered Into During the Year [(2)]	**(343)**	461
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**(8)**	4
Fair Value of Contracts, End of Year	**(291)**	271

(1) Includes a realized loss of $6 million related to power contracts (2015 – $10 million loss).
(2) Includes an increase of $7 million related to power contracts (2015 – $14 million decrease).

C) Earnings Impact of (Gains) Losses From Risk Management Positions

	Three Months Ended		**Twelve Months Ended**	
For the periods ended December 31,	**2016**	2015	**2016**	2015
Realized (Gain) Loss [(1)]	**(12)**	(239)	**(211)**	(656)
Unrealized (Gain) Loss [(2)]	**114**	26	**554**	195
(Gain) Loss on Risk Management	**102**	(213)	**343**	(461)

(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.

20. RISK MANAGEMENT

Cenovus is exposed to financial risks, including market risk related to commodity prices, foreign exchange rates, interest rates as well as credit risk and liquidity risk. 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, 2015. Exposure to these risks has not changed significantly since December 31, 2015. To manage exposure to interest rate volatility, the Company entered into interest rate swap contracts related to expected future debt issuances. As at December 31, 2016, Cenovus had a notional amount of US$400 million in interest rate swaps.

Net Fair Value of Risk Management Positions

As at December 31, 2016	Notional Volumes	Terms	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
Brent Fixed Price	10,000 bbls/d	July – December 2017	US$53.09/bbl	**(14)**
Brent Fixed Price	10,000 bbls/d	January – June 2018	US$54.06/bbl	**(11)**
WTI Fixed Price	70,000 bbls/d	January – June 2017	US$46.35/bbl	**(159)**
WTI Collars	50,000 bbls/d	July – December 2017	US$44.84 – US$56.47/bbl	**(52)**
WTI Collars	10,000 bbls/d	January – June 2018	US$45.30 – US$62.77/bbl	**(3)**
Other Financial Positions [(1)]				**(47)**
Crude Oil Fair Value Position				**(286)**
Interest Rate Swaps				**(5)**
Total Fair Value				**(291)**

(1) Other financial positions are part of ongoing operations to market the Company's production.

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 or interest rates, with all other variables held constant. Management believes the fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuating commodity prices or interest rates on the Company's open risk management positions could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

Risk Management Positions in Place as at December 31, 2016

	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$5.00 per bbl Applied to Brent, WTI and Condensate Hedges	**(198)**	**193**
Crude Oil Differential Price	± US$2.50 per bbl Applied to Differential Hedges Tied to Production	**1**	**(1)**
Interest Rate Swaps	± 50 Basis Points	**45**	**(52)**

21. COMMITMENTS AND CONTINGENCIES

A) Commitments

Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements. In addition, the Company has commitments related to its risk management program and an obligation to fund its defined benefit pension and other post-employment benefit plans. Additional information related to the Company's commitments can be found in the notes to the annual Consolidated Financial Statements for the year ended December 31, 2015.

For the year ended December 31, 2016, the Company's transportation commitments decreased approximately $1.1 billion primarily due to the use of contracts and changes in toll estimates. These agreements, some of which are subject to regulatory approval, are for terms up to 20 years subsequent to the date of commencement. As at December 31, 2016, total transportation commitments were $26 billion.

As at December 31, 2016, there were outstanding letters of credit aggregating $258 million issued as security for performance under certain contracts (December 31, 2015 – $64 million).

B) Legal Proceedings

Cenovus is involved in a limited number of legal claims associated with the normal course of operations. Cenovus believes that any liabilities that might arise from such matters, to the extent not provided for, are not likely to have a material effect on its Consolidated Financial Statements.

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)

Revenues	2016 Year	Q4	Q3	Q2	Q1	2015 Year
Gross Sales						
Upstream	**4,196**	**1,326**	1,123	1,003	744	4,739
Refining and Marketing	**8,439**	**2,477**	2,245	2,129	1,588	8,805
Corporate and Eliminations	**(353)**	**(108)**	(89)	(89)	(67)	(337)
Less: Royalties	**148**	**53**	39	36	20	143
Revenues	**12,134**	**3,642**	3,240	3,007	2,245	13,064

Operating Margin [1]	2016 Year	Q4	Q3	Q2	Q1	2015 Year
Crude Oil and Natural Gas Liquids						
Foster Creek	**399**	**165**	125	98	11	454
Christina Lake	**476**	**168**	140	134	34	592
Conventional	**402**	**100**	108	106	88	683
Natural Gas	**141**	**50**	47	10	34	307
Other Upstream Operations	**3**	**4**	(1)	-	-	18
	1,421	**487**	419	348	167	2,054
Refining and Marketing	**346**	**108**	68	193	(23)	385
Operating Margin	**1,767**	**595**	487	541	144	2,439

Adjusted Funds Flow [2]	2016 Year	Q4	Q3	Q2	Q1	2015 Year
Cash From Operating Activities	**861**	**164**	310	205	182	1,474
Deduct (Add Back):						
Net Change in Other Assets and Liabilities	**(91)**	**(32)**	(13)	(17)	(29)	(107)
Net Change in Non-Cash Working Capital	**(471)**	**(339)**	(99)	(218)	185	(110)
Adjusted Funds Flow	**1,423**	**535**	422	440	26	1,691
Per Share - Basic	**1.71**	**0.64**	0.51	0.53	0.03	2.07
- Diluted	**1.71**	**0.64**	0.51	0.53	0.03	2.07

Earnings	2016 Year	Q4	Q3	Q2	Q1	2015 Year
Operating Earnings (Loss) [3]	**(377)**	**321**	(236)	(39)	(423)	(403)
Per Share - Diluted	**(0.45)**	**0.39**	(0.28)	(0.05)	(0.51)	(0.49)
Net Earnings (Loss)	**(545)**	**91**	(251)	(267)	(118)	618
Per Share - Basic	**(0.65)**	**0.11**	(0.30)	(0.32)	(0.14)	0.75
- Diluted	**(0.65)**	**0.11**	(0.30)	(0.32)	(0.14)	0.75

Income Tax & Exchange Rates	2016 Year	Q4	Q3	Q2	Q1	2015 Year
Effective Tax Rates Using:						
Net Earnings [4]	**41.2%**					(15.1)%
Operating Earnings, Excluding Divestitures	**33.0%**					32.4%
Canadian Statutory Rate [5]	**27.0%**					26.1%
U.S. Statutory Rate	**38.0%**					38.0%
Foreign Exchange Rates *(US$ per C$1)*						
Average	**0.755**	**0.750**	0.766	0.776	0.728	0.782
Period End	**0.745**	**0.745**	0.762	0.769	0.771	0.723

(1) Operating Margin (previously labelled Operating Cash Flow) is an additional subtotal found in Note 1 of the Consolidated Financial Statements and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Margin is defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Margin.

(2) Adjusted Funds Flow (previously labelled Cash Flow) is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations. Adjusted Funds 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. Net change in other assets and liabilities is composed of site restoration costs and pension funding.

(3) Operating Earnings (Loss) is a non-GAAP measure that is used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating Earnings (Loss) is defined as Earnings (Loss) Before Income Tax excluding gain (loss) on discontinuance, gain on bargain purchase, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on Operating Earnings (Loss) before tax, excluding the effect of changes in statutory income tax rates and the recognition of an increase in U.S. tax basis.

(4) The 2015 effective tax rate reflects an increase to the tax basis of Cenovus's U.S. assets, the two percent increase in the Alberta corporate income tax rate and the benefit from recognition of previously unrecognized capital losses.

(5) On June 29, 2015, the Alberta government enacted a two percent increase in the corporate income tax rate. The rate increase was effective July 1, 2015.

Financial Metrics (Non-GAAP Measures)	2016 Year	Q4	Q3	Q2	Q1	2015 Year
Net Debt to Capitalization [1][2]	**18%**	**18%**	17%	17%	16%	16%
Debt to Capitalization [3][4]	**35%**	**35%**	35%	34%	34%	34%
Net Debt to Adjusted EBITDA [1][5]	**1.9x**	**1.9x**	2.0x	1.9x	1.3x	1.2x
Debt to Adjusted EBITDA [3][5]	**4.5x**	**4.5x**	5.3x	4.8x	3.6x	3.1x
Return on Capital Employed [6]	**(2)%**	**(2)%**	(6)%	6%	8%	5%
Return on Common Equity [7]	**(5)%**	**(5)%**	(10)%	7%	10%	5%

(1) Net debt includes the Company's short-term borrowings, and the current and long-term portions of long-term debt, net of cash and cash equivalents.

(2) Net debt to capitalization is defined as net debt divided by net debt plus shareholders' equity.

(3) Debt includes the Company's short-term borrowings and the current and long-term portions of long-term debt.

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

(5) Adjusted EBITDA is defined as earnings before finance costs, interest income, income tax expense, depreciation, depletion and amortization, goodwill impairments, asset impairments and reversals, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), net, calculated on a trailing twelve-month basis.

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

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

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics (continued)

Common Share Information	2016 Year	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Year
Common Shares Outstanding *(millions)*						
Period End	**833.3**	**833.3**	833.3	833.3	833.3	833.3
Average - Basic	**833.3**	**833.3**	833.3	833.3	833.3	818.7
Average - Diluted	**833.3**	**833.3**	833.3	833.3	833.3	818.7
Price Range *($ per share)*						
TSX - C$						
High	**22.07**	**22.07**	20.06	21.00	18.15	26.42
Low	**12.70**	**17.96**	17.15	16.12	12.70	15.75
Close	**20.30**	**20.30**	18.83	17.87	16.90	17.50
NYSE - US$						
High	**16.82**	**16.82**	15.72	16.56	13.97	21.12
Low	**9.10**	**13.36**	12.93	12.25	9.10	11.85
Close	**15.13**	**15.13**	14.37	13.82	13.00	12.62
Dividends *($ per share)*	**0.2000**	**0.0500**	0.0500	0.0500	0.0500	0.8524
Share Volume Traded *(millions)*	**1,491.7**	**322.6**	313.0	373.3	482.8	1,691.2

Net Capital Investment	2016 Year	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Year
Capital Investment *($ millions)*						
Oil Sands						
Foster Creek	**263**	**52**	54	68	89	403
Christina Lake	**282**	**60**	47	61	114	647
Total	**545**	**112**	101	129	203	1,050
Other Oil Sands	**59**	**16**	9	10	24	135
	604	**128**	110	139	227	1,185
Conventional	**171**	**57**	41	34	39	244
Refining and Marketing	**220**	**64**	51	53	52	248
Corporate	**31**	**10**	6	10	5	37
Capital Investment	**1,026**	**259**	208	236	323	1,714
Acquisitions	**11**	**-**	-	11	-	87
Divestitures	**(8)**	**-**	(8)	-	-	(3,344)
Net Acquisition and Divestiture Activity	**3**	**-**	(8)	11	-	(3,257)
Net Capital Investment	**1,029**	**259**	200	247	323	(1,543)

Operating Statistics - Before Royalties

Upstream Production Volumes	2016 Year	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Year
Crude Oil and Natural Gas Liquids *(bbls/d)*						
Oil Sands						
Foster Creek	**70,244**	**81,588**	73,798	64,544	60,882	65,345
Christina Lake	**79,449**	**82,808**	79,793	78,060	77,093	74,975
	149,693	**164,396**	153,591	142,604	137,975	140,320
Conventional						
Heavy Oil	**29,185**	**28,913**	28,096	28,500	31,247	34,888
Light and Medium Oil	**25,915**	**25,065**	25,311	26,177	27,121	30,486
Natural Gas Liquids [(1)]	**1,065**	**1,177**	1,074	799	1,208	1,253
	56,165	**55,155**	54,481	55,476	59,576	66,627
Total Crude Oil and Natural Gas Liquids	**205,858**	**219,551**	208,072	198,080	197,551	206,947
Natural Gas *(MMcf/d)*						
Oil Sands	**17**	**17**	18	18	17	19
Conventional	**377**	**362**	374	381	391	422
Total Natural Gas	**394**	**379**	392	399	408	441
Total Production [(2)] *(BOE/d)*	**271,525**	**282,718**	273,405	264,580	265,551	280,447

Upstream Sales Volumes	2016 Year	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Year
Crude Oil and Natural Gas Liquids *(bbls/d)*						
Oil Sands						
Foster Creek	**69,647**	**79,827**	76,318	62,089	60,169	64,467
Christina Lake	**79,481**	**81,398**	80,313	76,066	80,118	73,872
	149,128	**161,225**	156,631	138,155	140,287	138,339
Conventional						
Heavy Oil	**28,958**	**28,833**	27,953	28,294	30,764	35,597
Light and Medium Oil	**25,965**	**24,903**	25,359	26,407	27,210	30,517
Natural Gas Liquids [(1)]	**1,065**	**1,177**	1,074	799	1,208	1,253
	55,988	**54,913**	54,386	55,500	59,182	67,367
Total Crude Oil and Natural Gas Liquids	**205,116**	**216,138**	211,017	193,655	199,469	205,706
Natural Gas *(MMcf/d)*						
Oil Sands	**17**	**17**	18	18	17	19
Conventional	**377**	**362**	374	381	391	422
Total Natural Gas	**394**	**379**	392	399	408	441
Total Sales [(2)] *(BOE/d)*	**270,783**	**279,305**	276,350	260,155	267,469	279,206

(1) Natural gas liquids include condensate volumes.

(2) Natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six thousand cubic feet (Mcf) to one barrel (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. Given that the value ratio based on the current price of crude oil compared to natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.

Average Royalty Rates

(Excluding Impact of Realized Gain (Loss) on Risk Management)	2016 Year	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Year
Oil Sands						
Foster Creek	**0.0%**	**(0.9)%**	0.8%	1.0%	(4.9)%	1.9%
Christina Lake	**1.6%**	**1.8%**	1.6%	1.2%	1.2%	2.8%
Conventional Oil						
Pelican Lake	**12.5%**	**11.9%**	14.1%	14.3%	8.3%	9.0%
Weyburn	**23.6%**	**28.3%**	23.0%	23.9%	16.6%	17.7%
Other	**12.8%**	**19.3%**	10.4%	8.6%	12.0%	5.2%
Natural Gas Liquids	**13.5%**	**12.2%**	12.0%	15.0%	16.1%	5.6%
Natural Gas	**4.6%**	**5.3%**	4.5%	3.7%	4.3%	2.5%

Refining	2016 Year	2016 Q4	2016 Q3	2016 Q2	2016 Q1	2015 Year
Refinery Operations [(1)]						
Crude Oil Capacity *(Mbbls/d)*	**460**	**460**	460	460	460	460
Crude Oil Runs *(Mbbls/d)*	**444**	**421**	463	458	435	419
Heavy Oil	**233**	**223**	241	228	241	200
Light/Medium	**211**	**198**	222	230	194	219
Crude Utilization	**97%**	**92%**	101%	100%	95%	91%
Refined Products *(Mbbls/d)*	**471**	**448**	494	483	460	444

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

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Before Royalties (continued)

Selected Average Benchmark Prices	2016					2015
	Year	**Q4**	Q3	Q2	Q1	Year
Crude Oil Prices *(US$/bbl)*						
Brent	**45.04**	**51.13**	46.98	46.97	35.08	53.64
West Texas Intermediate ("WTI")	**43.32**	**49.29**	44.94	45.59	33.45	48.80
Differential Brent - WTI	**1.72**	**1.84**	2.04	1.38	1.63	4.84
Western Canadian Select ("WCS")	**29.48**	**34.97**	31.44	32.29	19.21	35.28
Differential WTI - WCS	**13.84**	**14.32**	13.50	13.30	14.24	13.52
Condensate (C5 @ Edmonton)	**42.47**	**48.33**	43.07	44.07	34.39	47.36
Differential WTI - Condensate (Premium)/Discount	**0.85**	**0.96**	1.87	1.52	(0.94)	1.44
Refining Margins 3-2-1 Crack Spreads [(1)] *(US$/bbl)*						
Chicago	**13.07**	**10.96**	14.58	17.15	9.58	19.11
Group 3	**12.27**	**10.95**	14.56	13.03	10.52	18.16
Natural Gas Prices						
AECO *(C$/Mcf)*	**2.09**	**2.81**	2.20	1.25	2.11	2.77
NYMEX *(US$/Mcf)*	**2.46**	**2.98**	2.81	1.95	2.09	2.66
Differential NYMEX - AECO *(US$/Mcf)*	**0.89**	**0.86**	1.13	0.99	0.56	0.49

(1) 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").

Netbacks [(1)]

(Excluding Impact of Realized Gain (Loss) on Risk Management)	2016					2015
	Year	**Q4**	Q3	Q2	Q1	Year
Heavy Oil - Foster Creek *($/bbl)*						
Sales Price	**30.32**	**38.59**	33.61	33.40	11.82	33.65
Royalties	**(0.01)**	**(0.27)**	0.19	0.23	(0.16)	0.47
Transportation and Blending	**8.84**	**7.37**	8.38	11.44	8.70	8.84
Operating	**10.55**	**10.60**	9.63	10.15	12.05	12.60
Netback	**10.94**	**20.89**	15.41	11.58	(8.77)	11.74
Heavy Oil - Christina Lake *($/bbl)*						
Sales Price	**25.30**	**34.78**	29.11	28.31	8.85	28.45
Royalties	**0.33**	**0.56**	0.41	0.28	0.05	0.67
Transportation and Blending	**4.68**	**4.08**	4.49	4.90	5.28	4.72
Operating	**7.48**	**8.15**	7.72	6.35	7.61	8.01
Netback	**12.81**	**21.99**	16.49	16.78	(4.09)	15.05
Total Heavy Oil - Oil Sands *($/bbl)*						
Sales Price	**27.64**	**36.67**	31.30	30.59	10.13	30.88
Royalties	**0.17**	**0.14**	0.30	0.26	(0.04)	0.58
Transportation and Blending	**6.62**	**5.71**	6.39	7.84	6.75	6.64
Operating	**8.91**	**9.37**	8.65	8.06	9.52	10.13
Netback	**11.94**	**21.45**	15.96	14.43	(6.10)	13.53
Heavy Oil - Conventional *($/bbl)*						
Sales Price	**35.82**	**40.72**	40.50	36.77	25.99	39.95
Royalties	**3.31**	**4.08**	3.97	3.95	1.40	2.97
Transportation and Blending	**4.60**	**4.90**	4.86	3.85	4.77	3.36
Operating	**13.38**	**14.69**	12.43	12.34	13.98	15.92
Production and Mineral Taxes	**0.01**	**0.01**	0.01	0.01	-	0.04
Netback	**14.52**	**17.04**	19.23	16.62	5.84	17.66
Light and Medium Oil *($/bbl)*						
Sales Price	**46.48**	**55.35**	48.97	48.09	34.36	50.64
Royalties	**9.28**	**14.87**	8.91	8.52	5.18	5.66
Transportation and Blending	**2.73**	**2.69**	2.71	2.77	2.73	2.91
Operating	**15.65**	**16.05**	13.94	16.21	16.34	16.27
Production and Mineral Taxes	**1.24**	**1.50**	1.48	1.18	0.82	1.41
Netback	**17.58**	**20.24**	21.93	19.41	9.29	24.39
Total Crude Oil *($/bbl)*						
Sales Price	**31.20**	**39.37**	34.66	33.89	15.91	35.41
Royalties	**1.77**	**2.38**	1.83	1.93	0.90	1.75
Transportation and Blending	**5.84**	**5.25**	5.74	6.56	5.89	5.51
Operating	**10.40**	**10.85**	9.79	9.80	11.14	12.05
Production and Mineral Taxes	**0.16**	**0.17**	0.18	0.16	0.11	0.22
Netback	**13.03**	**20.72**	17.12	15.44	(2.13)	15.88
Natural Gas Liquids *($/bbl)*						
Sales Price	**31.16**	**40.79**	29.71	28.11	24.99	30.98
Royalties	**4.21**	**4.97**	3.58	4.20	4.03	1.74
Netback	**26.95**	**35.82**	26.13	23.91	20.96	29.24
Total Liquids *($/bbl)*						
Sales Price	**31.20**	**39.38**	34.64	33.87	15.97	35.38
Royalties	**1.79**	**2.39**	1.84	1.94	0.92	1.75
Transportation and Blending	**5.81**	**5.22**	5.71	6.53	5.85	5.48
Operating	**10.35**	**10.80**	9.74	9.76	11.08	11.98
Production and Mineral Taxes	**0.16**	**0.17**	0.18	0.16	0.11	0.22
Netback	**13.09**	**20.80**	17.17	15.48	(1.99)	15.95
Total Natural Gas *($/Mcf)*						
Sales Price	**2.32**	**2.99**	2.49	1.53	2.31	2.92
Royalties	**0.10**	**0.15**	0.10	0.04	0.09	0.07
Transportation and Blending	**0.11**	**0.12**	0.10	0.13	0.10	0.11
Operating	**1.15**	**1.25**	1.05	1.06	1.23	1.20
Production and Mineral Taxes	**-**	**-**	0.01	-	-	0.01
Netback	**0.96**	**1.47**	1.23	0.30	0.89	1.53
Total [(2)] *($/BOE)*						
Sales Price	**27.01**	**34.53**	29.98	27.56	15.43	30.67
Royalties	**1.49**	**2.06**	1.55	1.51	0.82	1.40
Transportation and Blending	**4.56**	**4.20**	4.51	5.07	4.51	4.21
Operating	**9.51**	**10.05**	8.92	8.89	10.14	10.72
Production and Mineral Taxes	**0.12**	**0.13**	0.15	0.12	0.08	0.18
Netback	**11.33**	**18.09**	14.85	11.97	(0.12)	14.16
Realized Gain (Loss) on Risk Management						
Liquids *($/bbl)*	**3.23**	**0.91**	2.14	1.97	8.16	7.51
Natural Gas *($/Mcf)*	**-**	**-**	-	-	-	0.37
Total [(2)] *($/BOE)*	**2.44**	**0.70**	1.63	1.46	6.08	6.11

(1) Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis. Netback is defined as gross sales less royalties, transportation and blending, operating expenses and production and mineral taxes divided by sales volumes. Netbacks do not reflect non-cash write-downs of product inventory until the inventory is sold. Our calculation is consistent with the definition found in the Canadian Oil and Gas Evaluation Handbook. The crude oil sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. The reconciliation of the financial components of each Netback to Operating Margin can be found in Management's Discussion and Analysis and the Annual Information Form.

(2) Natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six thousand cubic feet (Mcf) to one barrel (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. Given that the value ratio based on the current price of crude oil compared to natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.