MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE PERIOD ENDED MARCH 31, 2020

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", the "Company", or "Cenovus", and means Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) dated April 28, 2020, should be read in conjunction with our March 31, 2020 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2019 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2019 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of April 28, 2020, unless otherwise indicated. This MD&A provides an update to our annual MD&A and contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus management ("Management") prepared the MD&A. The interim MD&As and the annual MD&A are reviewed by the Audit Committee and recommended for approval by the Cenovus Board of Directors (the "Board"). Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Basis of Presentation

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

Non-GAAP Measures and Additional Subtotals

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Netbacks, Adjusted Funds Flow, Operating Earnings, Free Funds Flow, Net Debt, Capitalization and Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. In addition, Operating Margin is considered an additional subtotal found in Note 1 of our Consolidated Financial Statements. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS.

The definition and reconciliation, if applicable, of each non-GAAP measure or additional subtotal is presented in the Operating and Financial Results, Liquidity and Capital Resources, or Advisory sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian integrated oil and natural gas company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. Operations include oil sands projects in northeast Alberta and established crude oil, natural gas liquids ("NGLs") and natural gas production in Alberta and British Columbia. Total production from our upstream assets averaged approximately 483,000 BOE per day for the three months ended March 31, 2020. We also conduct marketing activities and have ownership interest in refining operations in the United States ("U.S."). The refineries processed an average of 442,000 gross barrels per day of crude oil feedstock into an average of 460,000 gross barrels per day of refined products in the three months ended March 31, 2020.

We renamed our Deep Basin segment to Conventional segment in the first quarter of 2020 and our new resource play, Marten Hills was reclassified from the Oil Sands segment to the Conventional segment. For a description of our operations, refer to the Reportable Segments section of this MD&A.

Our Strategy

Our overall strategy is unchanged and continues to be focused on maximizing shareholder value through cost leadership and realizing the best margins for our products. We have flexibility in our business plan that allows us to focus on maintaining liquidity and preserving a resilient balance sheet by reducing spending, while maintaining safe and reliable operations. This is particularly important in the current economic environment. However, our longer-term plan remains focused on sustainably growing shareholder returns and reducing Net Debt as well as continuing to integrate Environmental, Social and Governance ("ESG") considerations into our business plan. We believe that maintaining a strong balance sheet will help Cenovus navigate through commodity price volatility. We aim to evaluate disciplined investment in our portfolio against dividends, share repurchases and achieving and maintaining the optimal debt level while targeting investment grade status. Our investment focus will be on areas where we believe we have the greatest competitive advantage. We plan to achieve our strategy by leveraging our strategic focus areas including our oil sands, conventional oil and natural gas assets, marketing, transportation and refining portfolio, and our people.

RESPONDING TO LOW OIL PRICES AND THE NOVEL CORONAVIRUS ("COVID-19")

During the first quarter, COVID-19 reached a pandemic state. Measures taken by governments around the world to contain the virus significantly reduced demand for crude oil along with other products and services. This caused a significant slowdown in the global economy and in turn market volatility and a crash of global stock markets. At the same time, the cooperation between the Organization of Petroleum Exporting Countries ("OPEC") and non-OPEC members, primarily Saudi Arabia and Russia, to manage global crude oil production levels broke down and each party increased their daily crude production, increasing overall global supply. The combination of these events resulted in a one-day decline in benchmark crude oil prices of 24 percent on March 9, 2020, the biggest one-day decline on record since 1991. Average benchmark crude oil prices in March declined approximately 50 percent compared with average prices in December 2019. This has resulted in a significant fall in our share price, similar to our peers, and a $12.7 billion drop in our market capitalization since the end of last year. In general, the oil and gas industry has reacted with reductions to capital and other spending, as well as production shut-ins, to try to manage through this price environment. The duration of the current commodity price volatility is uncertain.

Our financial framework and flexible business plan provide us with multiple options to prudently manage our balance sheet. On March 9, 2020, in response to the changing commodity price environment and to maintain the strength of our balance sheet, we announced a 32 percent reduction in capital spending, a temporary suspension of our crude-by-rail program and deferral of final investment decisions on new projects. On April 2, 2020, we announced additional measures to enhance our financial resilience in response to the low global oil price environment including further reductions to 2020 capital spending, operating costs and general and administrative ("G&A") expenses. Planned cost reductions total approximately $750 million compared with the initial guidance released in December 2019. The Company has also temporarily suspended its dividend. Updated 2020 guidance dated April 1, 2020 is available on our website at cenovus.com.

The Company has a $4.5 billion committed credit facility, with tranches maturing in late 2022 and late 2023, and subsequent to March 31, 2020 added an additional $1.1 billion committed facility, with a term of 364 days and at the lenders' option to extend for one year, to provide further support through the current economic downturn. A further $1.6 billion of uncommitted demand lines, are available to issue letters of credit or in some cases draw up to $600 million for general purposes, and the Company has no bond maturities until late 2022. These instruments provide ample liquidity and runway to sustain our operations through a prolonged market downturn. Under the terms of Cenovus's 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 was well below this limit at the end of the first quarter.

We believe the measures we have taken will provide us the financial capability to maintain our base business, deliver safe and reliable operations, and continue to challenge our cost structure. We are confident that commodity prices will eventually improve; however, the timing of that improvement is uncertain, and we expect continued volatility of crude oil and refined product prices and cash flow volatility in the near term.

The provincial and federal governments have recognized the serious impacts the collapse of oil prices and the spread of COVID-19 has had on the oil and gas industry and are expected to implement various programs to ensure the industry's longevity.

QUARTERLY OVERVIEW

The volatility and changing market conditions in the commodity price environment were the biggest driving factors of our first quarter results. Decreases in crude oil demand due to the demand destruction caused by the COVID-19 pandemic coupled with increased global crude oil supply resulting from the dispute between Saudi Arabia and Russia regarding production cuts drove prices lower. Average Brent and West Texas Intermediate ("WTI") crude oil benchmark prices fell 18 percent and 19 percent, respectively, compared with the fourth quarter of 2019. During the quarter, WTI benchmark crude price ranged from a high of US$63.27 per barrel to a low of US$20.09 per barrel, closing March at US$20.48 per barrel; averaging 16 percent lower than the first quarter of 2019.

Operationally, our upstream assets performed well in the quarter. Production averaged 482,594 BOE per day, helped by the Special Production Allowance ("SPA") announced by the Government of Alberta to provide curtailment relief equivalent to incremental increases in crude shipped by rail. As a result of our decision to temporarily suspend our crude-by-rail program, we will no longer be making use of credits under Alberta's SPA program in the near-term. Upstream operating costs were $7.33 per BOE, down nine percent compared with the first quarter of 2019.

Our Wood River and Borger refineries (the "Refineries") demonstrated good operational performance. While there were some unplanned outages at Wood River in the quarter, the Refineries achieved crude oil runs averaging 442,000 barrels per day. In the first quarter, Borger substantially completed a planned spring turnaround and Wood River carried out planned maintenance.

Crude oil prices continued to be volatile throughout the first quarter. The differential between WTI and Western Canadian Select ("WCS") prices at Hardisty widened to an average of US$20.53 per barrel, a 66 percent increase compared with the first quarter of 2019, due to high crude oil inventory levels resulting from lower than expected crude-by-rail shipments. The WTI price decline, the decrease in the benchmark WCS prices to US$25.64 per barrel (2019 – US$42.53 per barrel) and the use of higher priced condensate purchased in the fourth quarter of 2019 had a negative impact on our upstream financial results (operating margin).

In the first quarter of 2020, upstream operating margin was negative $214 million compared with operating margin of $935 million in 2019, due to a lower average realized crude oil sales price, non-cash inventory write-downs as a result of low prices and realized risk management losses of $25 million compared with gains of $12 million in 2019, partially offset by higher sales volumes.

Our Refining and Marketing segment operating margin was negative $375 million in the first quarter, a decrease of $679 million compared with the first quarter of 2019 primarily due to lower global crude oil and refined product pricing, which resulted in $253 million in non-cash inventory write-downs as well as lower crude advantage and decreased market crack spreads. The decrease was partially offset by higher realized margins on the sale of clean products and increased crude oil runs. Crude oil run rates in the first quarter of 2019 were reduced by unplanned outages which included a fire in a crude unit at the Wood River refinery.

In the first quarter of 2020, we:

- Realized an average crude oil sales price of $22.74 per barrel compared with $49.84 per barrel in the first quarter of 2019;
- Achieved Cash from Operating Activities of $125 million (2019 – $436 million), Adjusted Funds Flow deficit of $146 million (2019 – $1.0 billion), and Free Funds Flow deficit of $450 million (2019 – Free Funds Flow of $688 million);
- Recorded a Net Loss of $1,797 million compared with Net Earnings of $110 million in 2019;
- Recognized asset impairment charges of $318 million; and
- Repurchased US$100 million of our unsecured notes for US$81 million.

Subsequent to March 31, 2020, we added an additional $1.1 billion committed facility, with a term of 364 days and at the lenders' option to extend for one year, to provide further support through the current economic downturn. With this new facility we have $5.6 billion in committed facilities.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results

	Three Months Ended March 31,		
	2020	**Percent Change**	2019
Upstream Production Volumes			
Oil Sands (barrels per day)			
Foster Creek	**163,820**	**6**	154,156
Christina Lake	**223,216**	**18**	188,824
	387,036	**13**	342,980
Conventional (1) (BOE per day)	**95,558**	**(8)**	104,290
Total Production (BOE per day)	**482,594**	**8**	447,270
Sales (BOE per day)	**435,880**	**14**	381,444
Refining and Marketing			
Crude Oil Runs (2) (Mbbls/d)	**442**	**18**	375
Refined Product (2) (Mbbls/d)	**460**	**14**	402
Crude Utilization (2) (percent)	**89**	**11**	78
Crude-by-Rail (barrels per day)			
Crude-by-Rail Loads (3)	**96,043**	**651**	12,785
Crude-by-Rail Sales (4)	**103,243**	**564**	15,541

(1) *This segment was previously referred to as the Deep Basin segment.*
(2) *Represents 100 percent of the Wood River and Borger refinery operations. Cenovus's interest is 50 percent.*
(3) *Represents volumes transported outside of Alberta.*
(4) *Represents volumes sold outside of Alberta.*

Upstream Production Volumes

Our upstream operations performed well in the first quarter of 2020. Oil Sands production was 387,036 barrels per day (2019 – 342,980 barrels per day) due to the curtailment relief available under the SPA program and reduced restrictions from mandatory production curtailments set by the Government of Alberta compared with the first quarter of 2019. This was partially offset by the decision in March to operate at reduced levels due to the low commodity price environment as a result of COVID-19. Our upstream production curtailment limit increased by 64,098 barrels per day in the quarter due to the impact of the crude-by-rail SPA.

Conventional production in the first quarter of 2020 was 95,558 BOE per day compared with 104,290 BOE per day in 2019 due to natural declines from lower sustaining capital investment, partially offset by production in the Marten Hills area commencing in 2020 and less downtime for third-party pipeline outages.

Refining and Marketing

Crude oil runs and refined product output increased in the first quarter of 2020 compared with the same period in 2019. A planned turnaround at Borger and planned maintenance and unplanned outages at Wood River had less of an impact on operations than planned and unplanned maintenance at the Refineries in the first three months of 2019, which included a fire in a crude unit at Wood River.

Further information on the changes in our financial and operating results can be found in the Reportable Segments section of this MD&A. Further information on our risk management activities can be found in the Risk Management and Risk Factors section of this MD&A and in the notes to the Consolidated Financial Statements.

Selected Consolidated Financial Results

The impact of falling crude oil prices, lower refining throughput, and higher blending costs were the primary drivers of our financial results in the three months ended March 31, 2020. The following key performance measures are discussed in more detail within this MD&A.

($ millions, except per share amounts)	2020	2019				2018 [1] [2]			
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenues	3,968	4,838	4,736	5,603	5,004	4,545	5,857	5,832	4,610
Operating Margin [3]	(589)	864	1,080	1,277	1,239	135	1,191	911	157
Cash From Operating Activities	125	740	834	1,275	436	488	1,258	506	(134)
Adjusted Funds Flow [4]	(146)	687	928	1,082	1,005	7	980	767	(33)
Operating Earnings (Loss)	(1,187)	(164)	284	267	69	(1,670)	(41)	(292)	(752)
Per Share ($) [5]	(0.97)	(0.13)	0.23	0.22	0.06	(1.36)	(0.03)	(0.24)	(0.61)
Net Earnings (Loss)	(1,797)	113	187	1,784	110	(1,350)	(242)	(410)	(914)
Per Share ($) [5]	(1.46)	0.09	0.15	1.45	0.09	(1.10)	(0.20)	(0.33)	(0.74)
Capital Investment [6]	304	317	294	248	317	276	271	294	522
Dividends									
Cash Dividends	77	77	60	62	61	62	61	62	60
Per Share ($)	0.0625	0.0625	0.0500	0.0500	0.0500	0.0500	0.0500	0.0500	0.0500

(1) IFRS 16, "Leases" ("IFRS 16"), was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in our 2019 annual MD&A.
(2) Represented on a continuing basis.
(3) Additional subtotal found in Note 1 of the interim Consolidated Financial Statements and defined in this MD&A.
(4) Non-GAAP measure defined in this MD&A. The comparative periods have been reclassified to conform with the current period treatment of non-cash inventory write-downs.
(5) Represented on a basic and diluted per share basis.
(6) Includes expenditures on property, plant and equipment ("PP&E"), Exploration and Evaluation ("E&E") assets and assets held for sale.

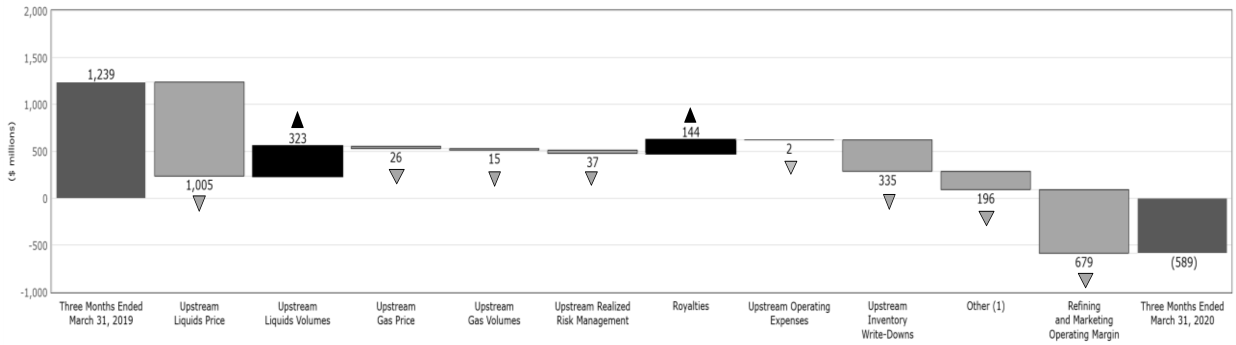
Operating Margin

Operating Margin is an additional subtotal found in Note 1 of the interim 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, inventory write-downs, 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.

	Three Months Ended March 31,	
($ millions)	**2020**	2019 [1]
Gross Sales	**4,238**	5,336
Less: Royalties	**47**	191
Revenues	**4,191**	5,145
Expenses		
Purchased Product	**1,944**	2,159
Transportation and Blending	**1,627**	1,166
Operating Expenses	**597**	596
Inventory Write-Downs	**588**	4
Realized (Gain) Loss on Risk Management Activities	**24**	(19)
Operating Margin	**(589)**	1,239

(1) The comparative period has been reclassified to conform with the current period treatment of non-cash inventory write-downs.

Operating Margin Variance



(1) *Other includes the value of condensate sold as heavy oil blend recorded in revenues and condensate costs recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.*

Operating Margin decreased in the first three months of 2020 compared with 2019 primarily due to:

- A lower average crude oil sales price resulting from lower benchmark pricing and wider differentials;
- Lower Operating Margin from our Refining and Marketing segment primarily due to $253 million in non-cash inventory write-downs as a result of declines in refined product and crude oil prices as well as lower crude advantage and reduced market crack spreads;
- Non-cash product inventory write-downs of $335 million related to our upstream assets;
- An increase in transportation and blending expenses due to higher priced condensate from inventory used for blending; and
- Upstream realized risk management losses of $25 million (2019 – gains of $12 million).

These decreases in Operating Margin were partially offset by higher liquids sales volumes and lower royalties due to lower realized prices.

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

Cash From Operating Activities and Adjusted Funds Flow

Adjusted Funds 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. Non-cash working capital is composed of accounts receivable, inventories (excluding non-cash inventory write-downs), income tax receivable, accounts payable and income tax payable. Net change in other assets and liabilities is composed of site restoration costs and pension funding.

($ millions)	**Three Months Ended March 31, 2020**	2019
Cash From Operating Activities	**125**	436
(Add) Deduct:		
Net Change in Other Assets and Liabilities	**(39)**	(21)
Net Change in Non-Cash Working Capital [(1)]	**310**	(548)
Adjusted Funds Flow [(1)]	**(146)**	1,005

(1) *The comparative period has been reclassified to conform with the current period treatment of non-cash inventory write-downs.*

Cash From Operating Activities and Adjusted Funds Flow were both lower compared with the first quarter of 2019 due to lower Operating Margin, partially offset by lower finance costs. The change in non-cash working capital in the first three months of 2020 was primarily due to a decrease in accounts receivable and inventory, partially offset by a decrease in accounts payable and income tax payable. The decrease in inventory excludes the impact of inventory write-downs until the inventory is sold.

In the first quarter of 2019, the change in non-cash working capital was primarily due to an increase in accounts receivable from higher blend prices for crude oil and higher inventory due to increased product volumes and costs, partially offset by an increase in accounts payable.

Operating Earnings (Loss)

Operating Earnings (Loss) is a non-GAAP measure 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, revaluation gain, 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.

($ millions)	Three Months Ended March 31, 2020	2019
Earnings (Loss), Before Income Tax	**(2,145)**	157
Add (Deduct):		
Unrealized Risk Management (Gain) Loss (1)	**22**	236
Non-Operating Unrealized Foreign Exchange (Gain) Loss (2)	**589**	(209)
(Gain) Loss on Divestiture of Assets	**1**	5
Operating Earnings (Loss), Before Income Tax	**(1,533)**	189
Income Tax Expense (Recovery)	**(346)**	120
Total Operating Earnings (Loss)	**(1,187)**	69

(1) *Includes the reversal of unrealized (gains) losses recorded in prior periods.*
(2) *Includes unrealized foreign exchange (gains) losses on translation of U.S. dollar denominated notes issued from Canada and foreign exchange (gains) losses on settlement of intercompany transactions.*

In the first quarter of 2020, Operating Loss increased compared with Operating Earnings in 2019 primarily due to lower Cash From Operating Activities and Adjusted Funds Flow, as discussed above, and inventory write-downs of $588 million due to low benchmark market prices, higher depreciation, depletion, and amortization ("DD&A") that included impairment losses of $315 million, partially offset by a gain on the re-measurement of the contingent payment of $130 million (2019 – $263 million loss) and lower G&A.

Net Earnings (Loss)

($ millions)	
Net Earnings (Loss) for the Three Months Ended March 31, 2019	**110**
Increase (Decrease) due to:	
Operating Margin	**(1,828)**
Corporate and Eliminations:	
Unrealized Risk Management Gain (Loss)	**214**
Unrealized Foreign Exchange Gain (Loss)	**(886)**
Re-measurement of Contingent Payment	**393**
Gain (Loss) on Divestiture of Assets	**4**
Expenses (1)	**176**
DD&A	**(377)**
Exploration Expense	**2**
Income Tax Recovery (Expense)	**395**
Net Earnings (Loss) for the Three Months Ended March 31, 2020	**(1,797)**

(1) *Includes Corporate and Eliminations realized risk management (gains) losses, general and administrative, onerous contract provisions, finance costs, interest income, realized foreign exchange (gains) losses, transaction costs, research costs, other (income) loss, net and Corporate and Eliminations revenues, purchased product, transportation and blending, and operating expenses.*

Our Net Loss of $1,797 million in the first quarter of 2020 was significantly lower than Net Earnings of $110 million in 2019 primarily due to lower Operating Earnings, as discussed above, non-operating foreign exchange losses of $589 million compared with gains of $209 million in 2019. These decreases to our Net Earnings were partially offset by a deferred income tax recovery of $348 million compared with an expense of $41 million and unrealized risk management losses of $22 million compared with $236 million in the first quarter of 2019.

Capital Investment

($ millions)	Three Months Ended March 31, 2020	2019 (1)
Oil Sands	**194**	211
Conventional (2)	**16**	17
Refining and Marketing	**61**	55
Corporate and Eliminations	**33**	34
Capital Investment (3)	**304**	317

(1) *In the first quarter of 2020, our new resource play, Marten Hills was reclassified from the Oil Sands segment to the Conventional segment. The comparative information has been reclassified.*
(2) *This segment was previously referred to as the Deep Basin segment.*
(3) *Includes expenditures on PP&E, E&E assets and assets held for sale.*

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

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

Key performance drivers for our financial results include commodity prices, quality and location price differentials, refining crack spreads as well as the U.S./Canadian dollar exchange rate. The following table shows selected market benchmark prices and the U.S./Canadian dollar average exchange rates to assist in understanding our financial results.

Selected Benchmark Prices and Exchange Rates [(1)]

(US$/bbl, unless otherwise indicated)	Q1 2020	Percent Change	Q1 2019	Q4 2019
Brent				
Average	**50.96**	**(20)**	63.88	62.50
WTI				
Average	**46.17**	**(16)**	54.90	56.96
Average Differential Brent-WTI	**4.79**	**(47)**	8.98	5.54
WCS at Hardisty ("WCS")				
Average	**25.64**	**(40)**	42.53	41.13
Average Differential WTI-WCS	**20.53**	**66**	12.37	15.83
Average (C$/bbl)	**34.11**	**(40)**	56.58	54.29
WCS at Nederland				
Average	**41.80**	**(27)**	57.12	51.47
Average Differential WTI-WCS at Nederland	**4.37**	**(297)**	(2.22)	5.49
West Texas Sour ("WTS")				
Average	**45.47**	**(15)**	53.71	57.26
Average Differential WTI-WTS	**0.70**	**(41)**	1.19	(0.30)
Condensate (C5 @ Edmonton)				
Average	**46.28**	**(8)**	50.50	53.01
Average Differential WTI-Condensate (Premium)/Discount	**(0.11)**	**(103)**	4.40	3.95
Average Differential WCS-Condensate (Premium)/Discount	**(20.64)**	**159**	(7.97)	(11.88)
Average (C$/bbl)	**61.71**	**(8)**	67.15	69.97
Average Refined Product Prices				
Chicago Regular Unleaded Gasoline ("RUL")	**51.99**	**(19)**	64.15	64.83
Chicago Ultra-low Sulphur Diesel ("ULSD")	**60.32**	**(22)**	77.10	78.09
Refining Margin: Average 3-2-1 Crack Spreads [(2)]				
Chicago	**8.79**	**(35)**	13.57	12.27
Group 3	**10.91**	**(26)**	14.80	14.60
Average Natural Gas Prices				
AECO [(3)] (C$/Mcf)	**2.14**	**10**	1.94	2.34
NYMEX (US$/Mcf)	**1.95**	**(38)**	3.15	2.50
Foreign Exchange Rate (US$ per C$1)				
Average	**0.744**	**(1)**	0.752	0.758
End of Period	**0.705**	**(6)**	0.748	0.770

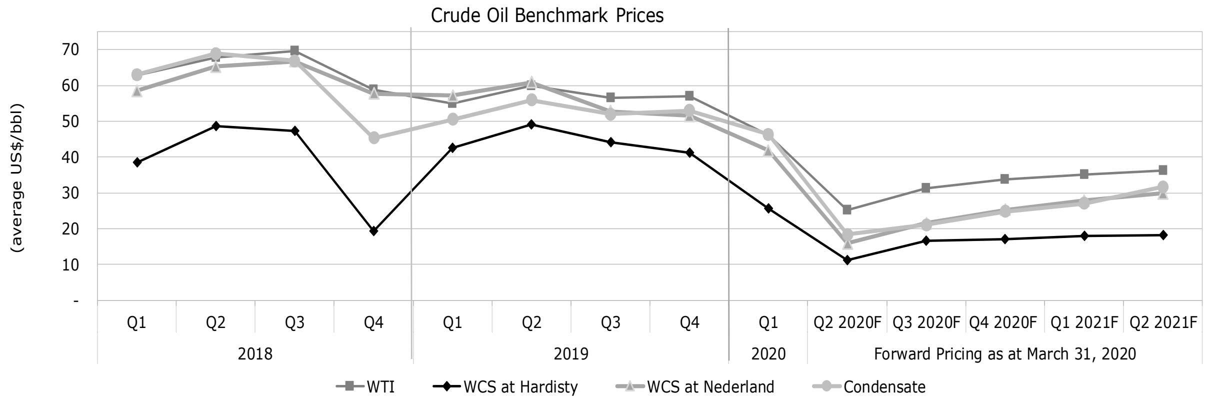
(1) These benchmark prices are not our realized sales prices and represent approximate values. For our average realized sales prices and realized risk management results, refer to the Netback tables in the Reportable Segments sections of this MD&A.
(2) The average 3-2-1 Crack Spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.
(3) Alberta Energy Company ("AECO") natural gas monthly index.

Crude Oil Benchmarks

In the first quarter of 2020, the average Brent and WTI crude oil benchmark prices declined as demand decreased significantly due to the COVID-19 pandemic combined with the increase in supply due to the collapse of coordinated output production cuts between OPEC and non-OPEC members, primarily Saudi Arabia and Russia.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and the Canadian dollar equivalent is the basis for determining royalty rates for a number of our crude oil properties. In the first quarter, the Brent-WTI differential decreased compared with the first quarter of 2019 as a result of pipeline capacity additions in 2019 and lower supply growth from the Permian basin, which decreased congestion at Cushing, Oklahoma.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. In the first quarter of 2020, high crude oil inventory levels and takeaway constraints (lower than expected crude-by-rail ramp up for the oil and gas industry) caused the average WTI-WCS differential to widen compared with the first quarter of 2019. Decreased production due to mandatory curtailments supported Alberta benchmark prices. WCS at Nederland is a heavy oil benchmark at the U.S. Gulf Coast ("USGC") which is representative of our pricing for our sales in the USGC. Heavy crude supply and demand remained tight globally and this was evident in the stronger pricing at the USGC in the first quarter of 2020. Key factors impacting pricing included the collapse of coordinated output production cuts on March 6, 2020 and U.S. sanctions against Venezuela and Iran.



WTS is an important North American crude oil benchmark, representing the heavier, more sour counterpart to WTI crude oil, and is a primary component of the input feedstock at the Borger refinery. The differential between WTI and WTS benchmark prices narrowed in the first quarter of 2020 compared with the first quarter of 2019, due to pipeline capacity additions in the latter part of 2019. In March 2020, the WTI-WTS differential widened as refiners adjusted their throughput to reflect lower demand.

Blending condensate with bitumen enables our production to be transported through pipelines. Our blending ratios, diluent volumes as a percentage of total blended volumes, range from approximately 25 percent to 33 percent. The WCS-Condensate differential is an important benchmark as a narrower differential generally results in an increase in the recovery of condensate costs when selling a barrel of blended crude oil. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by USGC condensate prices plus the cost to transport the condensate to Edmonton. Our blending costs are also impacted by the timing of purchases and deliveries of condensate into inventory to be available for use as well as timing of sales of blended product.

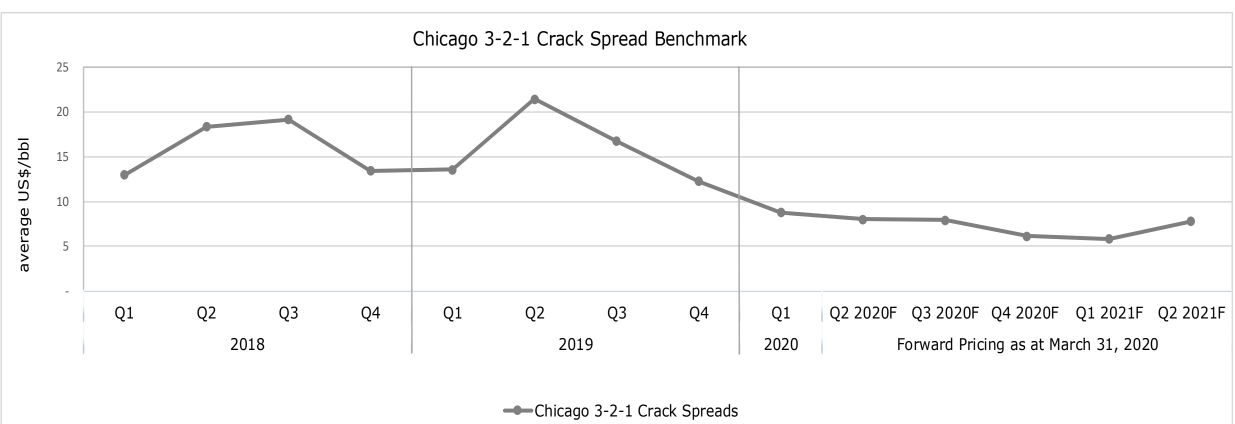
Average condensate differentials to WTI in Alberta were at a premium in the first three months of 2020 compared with a discount in 2019. The narrower spread in 2020 was due to more muted condensate supply growth in Canada and strong seasonal oil sands demand.

Refining Benchmarks

The Chicago Regular Unleaded Gasoline ("RUL") and Chicago Ultra-low Sulphur Diesel ("ULSD") benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 market crack spread. The 3-2-1 market 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 valued on a last in, first out accounting basis.

Average Chicago refined product prices decreased in the first quarter of 2020 primarily due to lower product demand as a result of COVID-19 and lower global crude oil prices. As North American refining crack spreads are expressed on a WTI basis, while refined products are set by global prices, the strength of refining market crack spreads in the U.S. Midwest and Midcontinent will reflect the differential between Brent and WTI benchmark prices.

Our realized crack spreads are affected by many other factors such as the variety of crude oil feedstock, refinery configuration and product output, the time lag between the purchase and delivery of crude oil feedstock, and the cost of feedstock, which is valued on a first in, first out ("FIFO") accounting basis.



Natural Gas Benchmarks

Average AECO prices strengthened during the first quarter of 2020 compared with 2019; however, they remained at low levels primarily due to lower demand as a result of warmer weather and oversupply from associated gas. Average NYMEX prices decreased compared with the first three months of 2019 due to lower demand.

Foreign Exchange Benchmark

Our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, NGLs, natural gas and refined products are determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar compared with the U.S. dollar has a negative impact on our reported results. Likewise, as the Canadian dollar weakens, there is a positive impact on our reported results. In addition to our revenues being denominated in U.S. dollars, our long-term debt is also U.S. dollar denominated. In periods of a weakening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange losses when translated to Canadian dollars.

In the first quarter of 2020, the Canadian dollar on average weakened relative to the U.S. dollar, compared with the first three months of 2019, resulting in a positive impact of approximately $40 million on our revenues. The weakening of the Canadian dollar relative to the U.S. dollar as at March 31, 2020 compared with December 31, 2019, resulted in unrealized foreign exchange losses of $589 million on the translation of our U.S. dollar debt.

REPORTABLE SEGMENTS

Our reportable segments are as follows:

Oil Sands, which includes the development and production of bitumen in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as other projects in the early stages of development.

Conventional, which includes assets rich in NGLs and natural gas within the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas in Alberta and British Columbia and the exploration for heavy oil in the Marten Hills area. The assets include interests in numerous natural gas processing facilities. We renamed our Deep Basin segment to Conventional in the first quarter of 2020 and our new resource play, Marten Hills, was reclassified from the Oil Sands segment to the Conventional segment. Comparative periods have been reclassified.

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.

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 reportable segment to which the derivative instrument relates. Eliminations include adjustments for internal usage of natural gas production between segments, transloading services provided to the Oil Sands segment by the Company's rail terminal, crude oil production used as feedstock by the Refining and Marketing segment, and unrealized intersegment profits in inventory. Eliminations are recorded at transfer prices based on current market prices.

Revenues by Reportable Segment

	Three Months Ended March 31,		
($ millions)	**2020**	**Percent Change**	2019
Oil Sands	**1,983**	**(12)**	2,250
Conventional [(1)]	**159**	**(23)**	206
Refining and Marketing	**2,049**	**(24)**	2,689
Corporate and Eliminations	**(223)**	**(58)**	(141)
	3,968	**(21)**	5,004

(1) This segment was previously referred to as the Deep Basin segment.

Oil Sands revenues decreased in the first quarter of 2020 compared with 2019 due to lower benchmark prices, partially offset by higher sales volumes and lower royalties. Conventional revenues declined in the first three months of 2020 compared with 2019 due to lower realized pricing and lower sales volumes, partially offset by lower royalties.

Refining and Marketing revenues declined 24 percent in the first quarter of 2020 compared with 2019. Refining revenues decreased due to lower refined product pricing consistent with the decline in average refined product benchmark prices. Revenues from third-party crude oil and natural gas sales undertaken by our marketing group decreased in the first three months of 2020 compared with 2019 due to lower prices and lower crude oil volumes, partially offset by higher natural gas volumes.

Corporate and Eliminations revenues relate to sales of natural gas or crude oil and operating revenue between segments and are recorded at transfer prices based on current market prices.

OIL SANDS

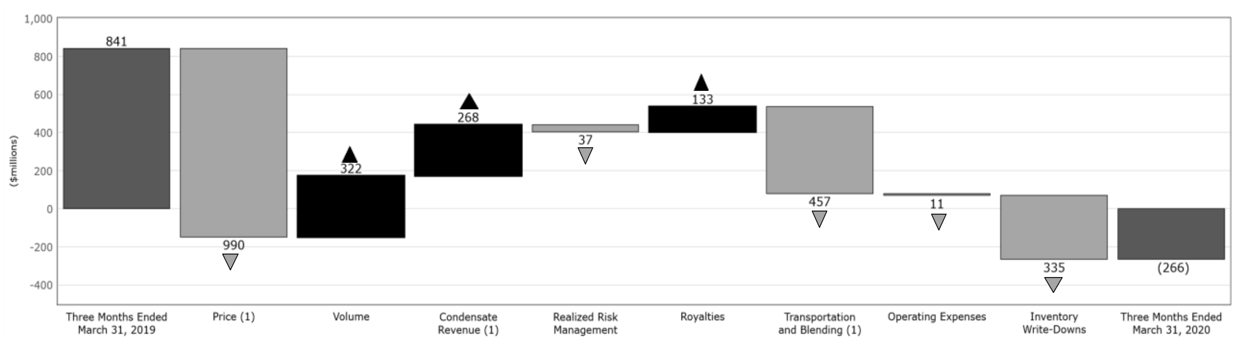
In the first quarter of 2020, we:

- Began to ramp up production to take advantage of the SPA program in January and February, prior to our voluntary production cuts in March due to the collapse of crude oil prices;
- Reduced our per-barrel operating costs to $7.75 per barrel compared with $9.06 per barrel in 2019;
- Realized crude oil Netbacks of $2.58 per barrel, excluding realized risk management activities and non-cash product inventory write-downs, a 91 percent decrease compared with 2019; and
- Generated Operating Margin of negative $266 million, a decrease of $1,107 million compared with the first quarter of 2019 due to lower average realized sales prices, non-cash product inventory write-downs of $335 million and increased condensate costs, partially offset by higher volumes and lower royalties.

Financial Results

($ millions)	Three Months Ended March 31, 2020	2019
Gross Sales	**2,027**	2,427
Less: Royalties	**44**	177
Revenues	**1,983**	2,250
Expenses		
Transportation and Blending	**1,604**	1,147
Operating	**285**	274
Inventory Write-Downs	**335**	-
(Gain) Loss on Risk Management	**25**	(12)
Operating Margin	**(266)**	841
Depreciation, Depletion and Amortization	**411**	369
Exploration Expense	**3**	5
Segment Income (Loss)	**(680)**	467

Operating Margin Variance



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

Revenues

Price

In the first quarter of 2020, our realized crude oil sales price was $22.35 per barrel compared with $49.67 per barrel in 2019. Our crude oil sales price decreased due to the lower WTI average benchmark price, the widening of the WTI-WCS differential by 66 percent to average discount of US$20.53 per barrel (2019 – discount of US$12.37 per barrel), the wider WCS-Christina Dilbit Blend ("CDB") differential, higher priced condensate from inventory used in blending, and a decrease in volumes sold outside of Alberta. The decrease in our crude oil price also reflects the wider WCS-Condensate premium of US$20.64 per barrel (2019 – premium of US$7.97 per barrel). In the first three months of 2020, we sold approximately 30 percent (2019 – approximately 18 percent) of our production at sales locations outside of Alberta, partially offsetting the decrease in our realized sales prices.

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Our realized crude oil sales price is influenced by the cost of condensate used in blending. Our blending ratios range between 25 percent and 33 percent. As the cost of condensate increases relative to the price of blended crude oil, our realized bitumen sales price decreases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets and deliver it to the Edmonton hub. As such, our average cost of condensate is generally higher than the Edmonton benchmark price due to transportation between market hubs and transportation to field locations. In addition, up to three months may elapse from when we purchase condensate to when we sell our blended production. In a declining crude oil price environment, we expect to see a negative impact on our realized bitumen sales price as we are using condensate purchased at a higher price earlier in the year.

Production Volumes

	Three Months Ended March 31,		
(barrels per day)	**2020**	**Percent Change**	2019
Foster Creek	**163,820**	**6**	154,156
Christina Lake	**223,216**	**18**	188,824
	387,036	**13**	342,980

Production levels in the first quarter of 2020 at Foster Creek and Christina Lake were higher compared with 2019 due to the ramp up of production to take advantage of the SPA program and the easing of mandated production curtailments, partially offset by voluntary production cuts in March 2020 to address the collapse of crude oil prices. In the first quarter of 2019, government mandated production curtailments were stricter, limiting our production.

Royalties

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

Royalties for a pre-payout project are based on a monthly calculation that applies a royalty rate (ranging from one percent to nine percent, based on the Canadian dollar equivalent WTI benchmark price) to the gross revenues from the project.

Royalties for a post-payout project are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one percent to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 percent to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales revenues less diluent costs and transportation costs. Net profits are a function of sales revenues less diluent costs, transportation costs, and allowed operating and capital costs.

Foster Creek and Christina Lake are post-payout projects for determining royalties.

Effective Royalty Rates

	Three Months Ended March 31,	
(percent)	**2020**	2019
Foster Creek	**11.7**	10.9
Christina Lake	**9.5**	17.4

In the first quarter of 2020, royalties decreased $133 million compared with 2019 due to lower revenue as a result of lower WCS pricing, combined with lower Alberta Department of Energy posted royalty rates resulting from decreased annual average WTI benchmark pricing. The Foster Creek royalty rate is slightly higher in the first quarter of 2020 due to smaller annual adjustments related to end of period filings compared with the same period of 2019.

Expenses

Transportation and Blending

Transportation and blending costs increased $457 million compared with the first quarter of 2019. Blending costs increased due to higher priced condensate and volumes. Our condensate costs were higher than the average Edmonton benchmark price primarily due to the transportation expense associated with moving the condensate between market hubs and to our oil sands projects and timing of when condensate was purchased.

Transportation costs increased primarily due to an increase in volumes shipped by rail due to the ramp-up under the SPA program increasing U.S. sales compared with the first quarter of 2019. In the first quarter of 2020, we transported approximately 30 percent of our volumes to U.S. destinations, either by pipeline or rail, allowing us to achieve better market prices. As a result of the current commodity price environment, we are temporarily suspending our crude-by-rail program and anticipate future transportation costs will be reduced until the underlying pricing fundamentals support continuation of our crude-by-rail program.

Per-unit Transportation Expenses

Foster Creek per-unit transportation costs increased $4.98 per barrel to $14.37 per barrel due to higher sales volumes shipped by rail to the U.S., partially offset by lower pipeline tariffs and increased total sales volumes. Christina Lake per-unit transportation costs increased $3.72 per barrel to $8.18 per barrel as a result of higher sales volumes shipped by rail and pipeline to the U.S., partially offset by increased total sales volumes.

Operating

Primary drivers of our operating expenses in the first quarter of 2020 were fuel, workforce, chemical costs, repairs and maintenance, and workovers. Total operating costs increased primarily due to more workovers, higher chemical costs due to increased production, higher workforce costs, and increased repairs and maintenance, partially offset by lower fuel costs.

Per-unit Operating Expenses

	Three Months Ended March 31,		
($/bbl)	**2020**	**Percent Change**	2019
Foster Creek			
Fuel	**2.69**	**(14)**	3.13
Non-fuel	**6.59**	**(10)**	7.31
Total	**9.28**	**(11)**	10.44
Christina Lake			
Fuel	**2.07**	**(26)**	2.80
Non-fuel	**4.55**	**(10)**	5.04
Total	**6.62**	**(16)**	7.84
Total	**7.75**	**(14)**	9.06

At Foster Creek and Christina Lake, per-barrel fuel costs decreased in the first quarter of 2020 due to higher sales volumes and lower natural gas prices, partially offset by higher natural gas consumption. In the first quarter of 2019, steam production levels were maintained at pre-curtailment levels. Steam production increased in the first quarter of 2020 due to the ramp up of production from the SPA program and the easing of mandated production curtailments.

Per-barrel non-fuel operating expenses at Foster Creek and Christina Lake decreased in the first quarter of 2020 compared with 2019 mainly due to higher sales volumes.

Inventory Write-Downs

As at March 31, 2020, non-cash inventory write-downs of $335 million related to crude oil blend and condensate were recorded due to low forward benchmark pricing. The product inventories were written down from cost to net realizable value and may be reversed in a subsequent period if the circumstances which caused it no longer exist and the inventory is still on hand. When the inventory is sold the cash impact is recognized.

Netbacks (1)

	Foster Creek		Christina Lake	
	Three Months Ended March 31,			
($/bbl)	**2020**	2019	**2020**	2019
Sales Price	**27.05**	51.99	**18.87**	47.63
Royalties	**1.47**	4.45	**1.01**	7.30
Transportation and Blending (2)	**14.37**	9.39	**8.18**	4.46
Operating Expenses	**9.28**	10.44	**6.62**	7.84
Netback Excluding Realized Risk Management	**1.93**	27.71	**3.06**	28.03
Realized Risk Management Gain (Loss)	**(0.61)**	0.39	**(0.74)**	0.42
Netback Including Realized Risk Management	**1.32**	28.10	**2.32**	28.45

(1) Netbacks reflect our margin on a per-barrel basis of unblended crude oil.
(2) The netbacks do not reflect non-cash write-downs of product inventory.

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. Our Netback calculation is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). Netbacks reflect our margin on a per-barrel of oil equivalent 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 the non-cash write-downs of product inventory until the product is sold. The sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Condensate is blended with the heavy oil to transport it to market. For a reconciliation of our Netbacks see the Advisory section of this MD&A.

Our average Netback, excluding realized risk management gains and losses, at Foster Creek and Christina Lake decreased in the first quarter of 2020 compared with 2019, primarily due to lower realized sales prices, higher per-unit transportation and blending costs partially offset by lower per-unit royalties and operating costs, and higher sales volumes. The weakening of the Canadian dollar relative to the U.S. dollar compared with 2019 had a positive impact on our reported sales price of approximately $0.24 per barrel.

In the first quarter of 2020, we sold approximately 30 percent (2019 – approximately 18 percent) of our Oil Sands production at sales locations outside of Alberta, partially offsetting the decrease in our realized sales prices and increase in transportation and blending costs.

Risk Management

Risk management positions in the first quarter of 2020 resulted in realized losses of $25 million (2019 – realized gains of $12 million) on condensate market optimization trades, due to average settled benchmark prices relative to our contract prices on hedging contracts.

DD&A and Exploration Expense

We deplete crude oil and natural gas properties on a unit-of-production basis over total proved reserves. The unit-of-production rate accounts for expenditures incurred to date, together with estimated future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by proved reserves.

In the first quarter of 2020, Oil Sands DD&A was $411 million and increased compared with 2019 due to higher sales volumes, partially offset by a decrease in our average depletion rates. Our depletion rate decreased due to lower future development costs and a decrease in maintenance capital. The average depletion rate for the first quarter of 2020 was approximately $10.40 per barrel (2019 – $11.20 per barrel).

We depreciate our right-of-use ("ROU") assets on a straight-line basis over the shorter of the estimated useful life or the lease term. The temporary suspension of our crude-by rail program was considered to be an indicator of impairment for the railcar cash-generating unit ("CGU"). As a result, the CGU was tested for impairment and an impairment loss of $3 million was recorded as additional depreciation.

Exploration expense of $3 million recorded in the first quarter of 2020 (2019 – $5 million) related to previously capitalized E&E costs was written off as the carrying value was not considered to be recoverable.

Capital Investment

	Three Months Ended March 31,	
($ millions)	**2020**	2019
Foster Creek	**89**	71
Christina Lake	**59**	121
	148	192
Other [1]	**46**	19
Capital Investment [2]	**194**	211

(1) Includes Narrows Lake, Telephone Lake and new resource plays. In Q1 2020, our new resource play, Marten Hills was reclassified from the Oil Sands segment to the Conventional segment. The comparative information has been reclassified.
(2) Includes expenditures on PP&E and E&E assets.

Oil Sands capital investment of $194 million focused on sustaining well programs related to existing production at Foster Creek and Christina Lake as well as the stratigraphic test well program. Other capital investment related to advancing key initiatives and technology development costs. In 2019, capital investment primarily related to the completion of Christina Lake phase G construction and sustaining capital and stratigraphic well programs.

Drilling Activity

	Gross Stratigraphic Test Wells		Gross Production Wells [1]	
Three Months Ended, March 31,	**2020**	2019	**2020**	2019
Foster Creek	**38**	14	**-**	-
Christina Lake	**42**	18	**-**	5
	80	32	**-**	5
Other	**75**	14	**-**	-
	155	46	**-**	5

(1) Steam-assisted gravity drainage well pairs are counted as a single producing well.

Stratigraphic test wells were drilled to help identify well pad locations for sustaining wells and near-term expansion phases, and to further progress the evaluation of emerging assets.

Future Capital Investment

On March 9, 2020 and April 2, 2020, we announced updates around key capital projects and our forecast capital spend for 2020. At current commodity prices we do not expect to sanction any new projects including phase H expansions at both Christina Lake and Foster Creek.

Oil Sands capital investment for 2020 is forecast to be between $370 million and $420 million. Updated 2020 guidance dated April 1, 2020 is available on our website at cenovus.com and reflects our decision to reduce overall capital spend levels in 2020 as a result of the challenging commodity price environment.

In 2020, our Technology and other capital investment has also been reduced to be between $35 million and $40 million, advancing only select strategic initiatives that are expected to provide both cost and environmental benefits.

CONVENTIONAL

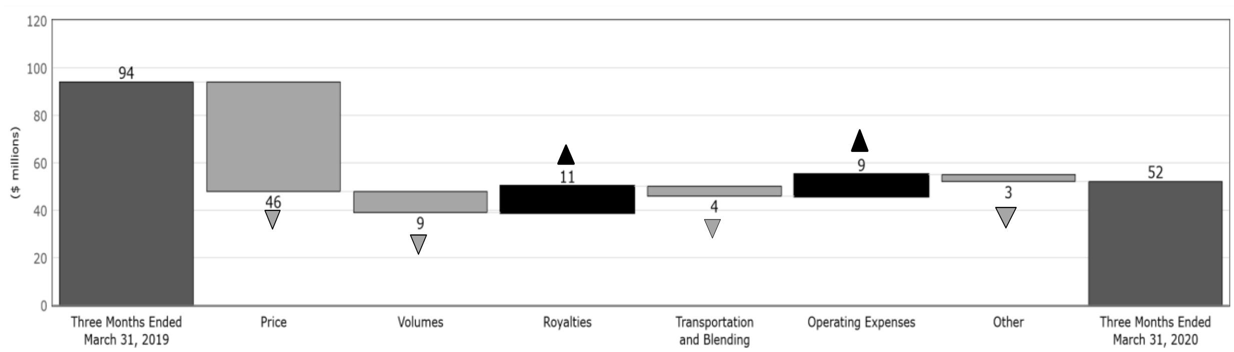
In the first quarter of 2020, we:

- Delivered total operating cost reductions to $84 million compared with $93 million in the same period of 2019, by optimizing operations, focusing on well interventions, maintenance and repair activities and leveraging our infrastructure;
- Produced a total of 95,558 BOE per day, a decrease compared with 2019 due to natural declines from lower sustaining capital investment, partially offset by production at Marten Hills and less downtime for third-party outages;
- Generated Operating Margin of $52 million, a decrease of $42 million due to lower realized sales prices and volumes, higher transportation and blending costs, partially offset by lower royalties and operating expenses;
- Recognized an impairment write-down of $315 million as a result of the decline in forward crude oil and natural gas prices; and
- Earned a Netback of $5.32 per BOE, excluding realized risk management activities.

Financial Results

	Three Months Ended March 31,	
($ millions)	**2020**	2019
Gross Sales	**162**	220
Less: Royalties	**3**	14
Revenues	**159**	206
Expenses		
Transportation and Blending	**23**	19
Operating	**84**	93
Operating Margin	**52**	94
Depreciation, Depletion and Amortization	**408**	86
Segment Income (Loss)	**(356)**	8

Operating Margin Variance



Revenues

Price

	Three Months Ended March 31, 2020	2019
Heavy Oil ($/bbl)	**29.09**	-
Light and Medium Oil ($/bbl)	**48.54**	59.79
NGLs ($/bbl)	**20.75**	28.53
Natural Gas ($/mcf)	**2.17**	2.89
Total Oil Equivalent ($/BOE)	**17.23**	21.86

In the first quarter of 2020, revenues declined due to lower realized sales prices and volumes. In 2020, we had heavy oil production from our new resource play, Marten Hills. In the first three months of 2020, revenues included $12 million of processing fee revenue related to our interests in natural gas processing facilities (2019 – $15 million). We do not include processing fee revenue in our per-unit pricing metrics or our Netbacks.

Production Volumes

	Three Months Ended March 31, 2020	2019
Liquids		
Crude Oil (barrels per day)	**8,662**	4,820
NGLs (barrels per day)	**21,104**	23,183
	29,766	28,003
Natural Gas (MMcf per day)	**395**	458
Total Production (BOE/d)	**95,558**	104,290
Natural Gas Production (percentage of total)	**69**	73
Liquids Production (percentage of total)	**31**	27

In the first quarter of 2020, production decreased from 2019 due to natural declines from lower sustaining capital investment, partially offset by Marten Hills heavy oil production starting in 2020 and less downtime from third-party pipeline outages.

Royalties

The Conventional assets are subject to royalty regimes in both Alberta and British Columbia. In Alberta, royalties benefit from a number of different programs that reduce the royalty rate on crude oil and natural gas production. Natural gas wells in Alberta also benefit from the Gas Cost Allowance ("GCA"), which reduces royalties, to account for capital and operating costs incurred to process and transport the Crown's portion of natural gas production.

In British Columbia, royalties also benefit from programs to reduce the rate on natural gas production. British Columbia applies a GCA, but only on natural gas processed through producer-owned plants. British Columbia also offers a Producer Cost of Service allowance, which reduces the royalty for the processing of the Crown's portion of natural gas production.

In the first quarter of 2020, our effective royalty rate was 3.8 percent for liquids (2019 – 11.7 percent) and 1.5 percent for natural gas (2019 – 3.4 percent) due to the GCA royalty credit being higher than royalty expenses as a result of declines in price and production.

Expenses

Transportation

Per unit transportation costs averaged $2.55 per BOE in the first quarter of 2020 compared with $2.06 per BOE in 2019, due to lower sales volumes and increased pipeline costs. Our transportation costs reflect charges for the movement of crude oil, NGLs and natural gas from the point of production to where the product is sold. The majority of our Conventional production is sold into the Alberta market.

Operating

Total operating costs in the first quarter of 2020 decreased 10 percent to $84 million (2019 – $93 million) as a result of optimizing operations, focusing on well interventions, repair and maintenance activities and leveraging our infrastructure to lower the cost structure.

Per-unit operating costs declined to an average of $9.01 per BOE in the first quarter of 2020 (2019 – $9.24 per BOE). The decrease in per-unit operating costs was driven by decreased workforce costs, property tax and lease costs primarily for lower lease rentals, and lower repairs and maintenance activity, partially offset by lower sales volumes and higher waste fluid handling and trucking costs for Marten Hills operations.

Netbacks

($/BOE)	Three Months Ended March 31, 2020	2019
Sales Price	**17.23**	21.86
Royalties	**0.39**	1.43
Transportation and Blending	**2.55**	2.06
Operating Expenses	**9.01**	9.24
Production and Mineral Taxes	**(0.04)**	0.03
Netback Excluding Realized Risk Management	**5.32**	9.10
Realized Risk Management Gain (Loss)	**-**	(0.01)
Netback Including Realized Risk Management	**5.32**	9.09

DD&A and Exploration Expense

We deplete crude oil and natural gas properties on a unit-of-production basis over proved reserves. The unit-of-production rate accounts for expenditures incurred to date, together with future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by proved reserves. The average depletion rate was approximately $10.80 per BOE in the first quarter of 2020 (2019 – $9.15 per BOE).

For the first quarter of 2020, DD&A was $408 million (2019 – $86 million). The increase was due to an impairment write-down of $315 million as a result of the decline in forward crude oil and natural gas prices and higher DD&A rates.

Capital Investment

In the first quarter of 2020, we invested $16 million compared with $17 million in 2019. Capital investment continued to focus on the disciplined development of our Conventional assets, which encompasses maintaining safe and reliable operations, acquiring seismic data, and completing preliminary work associated with preparing for future drilling and infrastructure.

($ millions)	Three Months Ended March 31, 2020	2019 (1)
Seismic	**5**	-
Drilling and Completions	**1**	2
Facilities	**6**	5
Other	**4**	10
Capital Investment (2)	**16**	17

(1) In Q1 2020, our new resource play, Marten Hills was reclassified from the Oil Sands segment to the Conventional segment. The comparative information has been reclassified.
(2) Includes expenditures on PP&E and E&E assets.

Drilling Activity

In the first quarter of 2020 there were no net wells drilled or completed and two wells were tied-in. In the same period of 2019, there were no net wells drilled, completed, or tied-in.

Future Capital Investment

On March 9, 2020, we provided an update indicating most of the remaining planned capital spend on our Conventional assets, including Marten Hills, had been suspended. In 2020, Conventional capital investment is forecast to be between $30 million and $35 million, substantially reduced from our original budget due to the current commodity price environment.

Updated 2020 Guidance dated April 1, 2020 is available on our website at cenovus.com.

REFINING AND MARKETING

In the first quarter of 2020, we:

- Achieved crude oil runs averaging 442,000 barrels per day, higher than the first quarter of 2019;
- Increased rail volumes loaded at the Bruderheim crude-by-rail terminal, averaging 81,167 barrels per day compared with 52,833 barrels per day in the first quarter of 2019. The crude-by-rail program was suspended late in the quarter and began to ramp down due to the low commodity prices environment; and
- Realized Operating Margin of negative $375 million, a decrease of $679 million compared with 2019, due to lower global crude oil and refined product pricing, which resulted in $253 million in non-cash inventory write-downs as well as decreases in both crude advantage and market crack spreads.

Financial Results

($ millions)	Three Months Ended March 31, 2020	2019 [1]
Revenues	**2,049**	2,689
Purchased Product	**1,944**	2,159
Gross Margin	**105**	530
Expenses		
Operating	**228**	229
Inventory Write-Downs	**253**	4
(Gain) Loss on Risk Management	**(1)**	(7)
Operating Margin	**(375)**	304
Depreciation, Depletion and Amortization	**79**	80
Segment Income (Loss)	**(454)**	224

(1) *The comparative period has been reclassified to conform with current period treatment of non-cash inventory write-downs.*

Refinery Operations [1]

	Three Months Ended March 31, 2020	2019
Crude Oil Capacity (Mbbls/d)	**495**	482
Crude Oil Runs (Mbbls/d)	**442**	375
Heavy Crude Oil	**197**	143
Light/Medium	**245**	232
Refined Products (Mbbls/d)	**460**	402
Gasoline	**230**	213
Distillate	**151**	135
Other	**79**	54
Crude Utilization (percent)	**89**	78

(1) *Represents 100 percent of the Wood River and Borger refinery operations. Cenovus's interest is 50 percent.*

On a 100 percent basis, the Refineries had total processing capacity re-rated on January 1, 2020 to 495,000 gross barrels per day of crude oil, including processing capability of up to 275,000 gross barrels per day of blended heavy crude oil. The ability to process a wide slate of crude oils allows the Refineries to economically integrate heavy crude oil production. Processing less expensive crude oil relative to WTI creates a feedstock cost advantage, illustrated by the discount of both WCS and WTS relative to WTI. The amount of heavy crude oil processed, such as WCS and CDB, is dependent on the quality and quantity of available crude oil with the total input slate optimized at each refinery to maximize economic benefit. Crude utilization represents the percentage of total crude oil processed in the Refineries relative to the total capacity.

Crude oil runs and refined product output increased in the first quarter of 2020 as the planned spring turnaround at Borger and planned maintenance and unplanned outages at Wood River had less of an impact on operations compared with planned maintenance and unplanned outages at both Refineries, including a fire in the crude unit at Wood River in 2019. Late in the quarter, the Refineries began to reduce crude rates in response to the economic slowdown and reduced demand for refined products resulting from COVID-19.

Crude-By-Rail Terminal

In the first quarter of 2020, we loaded an average of 81,167 barrels per day (65,751 barrels per day of our volumes) from our Bruderheim crude-by-rail terminal compared with an average of 52,833 barrels per day (34,187 barrels per day of our volumes) in the same period of 2019. On March 9, 2020, we announced our crude-by-rail program would be temporarily suspended as a response to low crude oil prices.

Gross Margin

The refining realized crack spread, which is the gross margin on a per-barrel basis, is affected by many factors, such as the variety of feedstock crude oil processed; refinery configuration and the proportion of gasoline, distillate and secondary product output; the time lag between the purchase of crude oil feedstock and the processing of that crude oil through the Refineries; and the cost of feedstock. Feedstock costs are valued on a FIFO accounting basis.

In the first quarter of 2020, Refining and Marketing gross margin decreased $425 million relative to the first quarter of 2019, primarily due to lower global crude oil and refined product pricing, which led to lower crude advantage and decreased market crack spreads, partially offset by higher realized margins on the sale of clean products and increased crude oil runs as 2019 rates were reduced by unplanned outages, including a fire in the crude unit at Wood River. Our gross margin was positively impacted by approximately $1 million due to the weakening of the Canadian dollar relative to the U.S. dollar in the first quarter of 2020 compared with the first quarter of 2019.

In the first quarter of 2020, the cost of Renewable Identification Numbers ("RINs") was $32 million compared with $26 million in 2019. RIN costs increased, primarily due to higher volume obligations.

Operating Expense

Primary drivers of operating expenses in the first quarter of 2020 were labour, maintenance and utilities. Operating expenses were relatively flat as unplanned outages at Wood River and turnaround costs at Borger in the first quarter of 2020 offset the planned maintenance and costs related to a fire at the Wood River refinery in the same period of 2019.

Inventory Write-Downs

As a result of a decline in refined product and crude oil prices, non-cash inventory write-downs of $253 million were recorded related to our refined product and feedstock inventory in the first quarter of 2020 (2019 – $4 million). Inventories were written down from cost to net realizable value and may be reversed in a subsequent period if the circumstances which caused it no longer exist and the inventory is still on hand.

DD&A

Refining and the crude-by-rail terminal assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 60 years. The service lives of these assets are reviewed on an annual basis. ROU assets are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. Refining and Marketing DD&A was $79 million in the first quarter of 2020 (2019 – $80 million).

Capital Investment

	Three Months Ended March 31,	
($ millions)	**2020**	2019
Wood River Refinery	**31**	23
Borger Refinery	**20**	26
Marketing	**10**	6
Capital Investment	**61**	55

Capital expenditures in the first quarter of 2020 focused primarily on reliability and maintenance projects, and yield enhancements projects as well as strategic rail initiatives and infrastructure.

In 2020, we expect to invest between $270 million and $300 million, a reduction from our original guidance and will continue to focus on sustaining refining operations. Our updated 2020 guidance dated April 1, 2020 is available on our website at cenovus.com.

CORPORATE AND ELIMINATIONS

In the three months ended March 31, 2020, our risk management activities resulted in unrealized risk management loss of $22 million (2019 – loss of $236 million) and a realized foreign exchange hedge loss of $5 million (2019 – gains of $1 million on foreign exchange contracts and loss of $1 million on interest rate swaps).

Expenses

	Three Months Ended March 31,	
($ millions)	**2020**	2019
General and Administrative	**(21)**	72
Onerous Contract Provisions	**(2)**	(1)
Finance Costs	**107**	124
Interest Income	**(1)**	(2)
Foreign Exchange (Gain) Loss, Net	**637**	(198)
Re-measurement of Contingent Payment	**(130)**	263
Research Costs	**3**	4
(Gain) Loss on Divestiture of Assets	**1**	5
Other (Income) Loss, Net	**(9)**	9
	585	276

General and Administrative

Primary drivers of our general and administrative expenses were employee long-term incentive costs, workforce costs, and operating costs associated with our real estate portfolio. In the first three months of 2020, G&A expenses decreased $93 million compared with the same period of 2019 primarily due to lower employee long-term incentive costs due to the decrease in our share price. On April 2, 2020, we announced G&A reductions of about $50 million compared with our initial guidance. Updated guidance dated April 1, 2020 is available on our website at cenovus.com

Onerous Contract Provisions

Onerous contract provisions are composed of non-lease components of real estate contracts which consist of operating costs and unreserved parking. In the first quarter of 2020, we recorded a non-cash recovery for onerous contracts of $2 million compared with a non-cash recovery of $1 million in the first quarter of 2019.

Finance Costs

In the first quarter of 2020, finance costs decreased by $17 million, primarily due to a reduction of total debt compared with March 31, 2019.

The weighted average interest rate on outstanding debt for the three months ended March 31, 2020 was 5.0 percent (2019 – 5.1 percent).

Foreign Exchange

	Three Months Ended March 31,	
($ millions)	**2020**	2019
Unrealized Foreign Exchange (Gain) Loss	**657**	(229)
Realized Foreign Exchange (Gain) Loss	**(20)**	31
	637	(198)

In the first quarter of 2020, unrealized foreign exchange losses of $657 million were recorded primarily as a result of the translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar as at March 31, 2020 was weaker compared with December 31, 2019, resulting in unrealized losses.

Re-measurement of Contingent Payment

Related to oil sands production, Cenovus has agreed to make quarterly payments to ConocoPhillips Company and certain of its subsidiaries ("ConocoPhillips") during the five years subsequent to the closing date of the acquisition of Conventional assets, previously Deep Basin assets, from ConocoPhillips in conjunction with their 50 percent interest in the FCCL Partnership on May 17, 2017 ("the Acquisition"), for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. The quarterly payment is $6 million for each dollar that the WCS price exceeds $52 per barrel. There are no maximum payment terms. The calculation includes an adjustment mechanism related to certain significant production outages at Foster Creek and Christina Lake, which may reduce the amount of a contingent payment.

The contingent payment is accounted for as a financial option. The fair value of $13 million as at March 31, 2020 was estimated by calculating the present value of the future expected cash flows using an option pricing model. The contingent payment is re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. For the three months ended March 31, 2020, a non-cash re-measurement gain of $130 million was recorded.

Average WCS forward pricing for the remaining term of the contingent payment is $25.74 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately $13.90 per barrel and $31.70 per barrel.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements, office furniture, and certain ROU assets. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. ROU assets (real estate assets) are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. DD&A in the first three months ended March 31, 2020 was $45 million (2019 – $31 million). The increase in DD&A compared with 2019 was primarily due an impairment loss of $8 million related to leasehold improvements and the annual review of useful lives.

Income Tax

	Three Months Ended March 31,	
($ millions)	**2020**	2019
Current Tax		
Canada	**-**	4
United States	**-**	2
Current Tax Expense (Recovery)	**-**	6
Deferred Tax Expense (Recovery)	**(348)**	41
Total Tax Expense (Recovery)	**(348)**	47

Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus and its subsidiaries operate are subject to change. We believe that our provision for income taxes is adequate. There are usually a number of tax matters under review and with consideration of the current economic environment, income taxes are subject to measurement uncertainty. The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation.

A deferred tax recovery was recorded in the three months ended March 31, 2020 due to losses, excluding unrealized foreign exchange losses on long term debt, incurred in the current quarter. In the three months ended March 31, 2019, current tax expense was recorded on current operations, net of prior year losses.

Our effective tax rate is a function of the relationship between total tax expense (recovery) and the amount of earnings (loss) before income taxes. The effective tax rate differs from the statutory tax rate as it reflects different tax rates in other jurisdictions, non-taxable foreign exchange (gains) losses, adjustments for changes in tax rates and other tax legislation, adjustments to the tax basis of the refining assets, variations in the estimate of reserves, differences between the provision and the actual amounts subsequently reported on the tax returns, and other permanent differences.

Capital Investment

Capital expenditures of $33 million for the first quarter of 2020 focused primarily on investments in technology and equipment and infrastructure to modernize our workplace, improve our cost structure and better manage risk.

In March and April 2020, we reduced our budget and are now forecasting to invest between $45 million and $55 million, which includes supporting essential initiatives for Refining and Marketing, upstream site safety, and ensuring the reliability and security of core systems and technological infrastructure to reduce costs and risk. Updated guidance dated April 1, 2020 is available on our website at cenovus.com.

LIQUIDITY AND CAPITAL RESOURCES

Our financial framework and flexible business plan provide us with multiple options to prudently manage our balance sheet. We have implemented additional measures to enhance our financial resilience in response to the low global crude oil price environment. Since the onset of the current market conditions, we have reduced our planned 2020 capital spending by $600 million, G&A costs by about $50 million, and operating cost reductions by about $100 million from the budget released in December and temporarily suspended our dividend.

	Three Months Ended March 31,	
($ millions)	**2020**	2019
Cash From (Used In)		
Operating Activities	**125**	436
Investing Activities	**(321)**	(314)
Net Cash Provided (Used) Before Financing Activities	**(196)**	122
Financing Activities	**182**	(652)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(12)**	(7)
Increase (Decrease) in Cash and Cash Equivalents	**(26)**	(537)

	March 31, 2020	December 31, 2019
Cash and Cash Equivalents	**160**	186
Debt	**7,581**	6,699

As at March 31, 2020, we were in compliance with all of the terms of our debt agreements.

Cash From (Used In) Operating Activities

For the first three months of 2020, cash generated by operating activities decreased compared with 2019 mainly due to lower Operating Margin, excluding non-cash inventory write-downs, as discussed in the Operating and Financial Results section of this MD&A, partially offset by a decrease in finance costs, as discussed in the Corporate and Eliminations section of this MD&A and changes in non-cash working capital, as discussed in the Operating and Financial Results section of this MD&A.

Excluding risk management assets and liabilities and the current portion of the contingent payment, our working capital was negative $657 million at March 31, 2020 compared with $839 million at December 31, 2019.

We anticipate that we will continue to meet our payment obligations as they come due.

Cash From (Used In) Investing Activities

Cash used in investing activities was slightly higher compared with the first quarter of 2019 primarily due to the fourth quarter contingent payment of $14 million paid in February 2020.

Cash From (Used In) Financing Activities

In the first quarter of 2020, cash provided from financing activities increased $834 million from 2019 primarily as a result of an increase in short-term borrowings in 2020 and higher debt repayments in 2019.

During the quarter, we repurchased US$100 million of unsecured notes for cash of US$81 million. In the first quarter of 2019, we repurchased US$449 million of unsecured notes for cash of US$419 million. Total debt including short-term borrowings as at March 31, 2020 was $7,581 million (December 31, 2019 – $6,699 million).

Dividends

In the first quarter of 2020, we paid dividends of $0.0625 per common share or $77 million (2019 – $0.05 per common share or $61 million). On April 2, 2020 we announced the temporary suspension of our dividend in response to the low global crude oil price environment. The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Available Sources of Liquidity

In light of the current economic crisis, we expect to fund our near-term cash requirements through prudent use of our balance sheet capacity including draws on our committed credit facilities and our uncommitted bilateral demand lines and other corporate and financial opportunities that may be available to us. We remain committed to maintaining our investment grade credit ratings at S&P Global Ratings and DBRS Limited and re-establishing investment grade ratings at both Moody's Investor Service ("Moody's") and Fitch Ratings ("Fitch").

The following sources of liquidity are available at March 31, 2020:

($ millions)	Term	Amount
Cash and Cash Equivalents	**Not applicable**	**160**
Committed Credit Facility – Tranche A	**November 2023**	**3,205**
Committed Credit Facility – Tranche B	**November 2022**	**1,200**
Uncommitted Demand Facilities		
Cenovus Energy Inc.	**Not applicable**	**143**
WRB Refining LP (Cenovus's proportionate share)	**Not applicable**	**50**

Committed Credit Facilities

We have a committed credit facility in place that consists of a $1.2 billion tranche maturing on November 30, 2022 and a $3.3 billion tranche maturing November 30, 2023. As at March 31, 2020, $95 million was drawn on our committed credit facility. Subsequent to March 31, 2020, we added another committed credit facility with capacity of $1.1 billion, with a term of 364 days and at the lenders' option to extend for one year, to further support our financial resilience in the current market environment.

Uncommitted Demand Facilities

Cenovus has uncommitted demand facilities of $1.6 billion in place, of which $600 million may be drawn for general purposes or the full amount can be available to issue letters of credit. As at March 31, 2020, the Company had drawn $457 million (December 31, 2019 - $nil) on these facilities and there were outstanding letters of credit aggregating to $415 million (December 31, 2019 - $364 million).

WRB Refining LP ("WRB") has uncommitted demand facilities of US$275 million (the Company's proportionate share - US$138 million) available to cover short-term working capital requirements. As at March 31, 2020, US$205 million (December 31, 2019 – $nil) was drawn, of which US$103 million ($145 million) was the Company's proportionate share.

Base Shelf Prospectus

Cenovus has in place a base shelf prospectus which expires in October 2021. As at March 31, 2020, US$5.0 billion remains available under the base shelf prospectus. Offerings under the base shelf prospectus are subject to market conditions.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Net Debt to Adjusted EBITDA and Net Debt to Capitalization. We define our non-GAAP measure of Net Debt as short-term borrowings, and the current and long-term portions of long-term debt, net of cash and cash equivalents and short-term investments. We define Capitalization as Net Debt plus Shareholders' Equity. We define Adjusted EBITDA as net earnings before finance costs, interest income, income tax expense, DD&A, E&E Write-down, goodwill impairments, asset impairments and reversals, unrealized gains (losses) on risk management, foreign exchange gains (losses), revaluation gain, re-measurement of contingent payment, gains (losses) on divestiture of assets, and other income (loss), net, calculated on a trailing twelve-month basis. These measures are used to steward our overall debt position and as measures of our overall financial strength.

	March 31, 2020	December 31, 2019
Net Debt to Capitalization [1] (percent)	**30**	25
Net Debt to Adjusted EBITDA	**3.1x**	1.6x

(1) Net Debt to Capitalization is defined as Net Debt divided by Net Debt plus Shareholders' Equity.

Cenovus targets a Net Debt to Adjusted EBITDA ratio of less than 2.0 times over the long-term. This ratio may periodically be above the target due to factors such as persistently low commodity prices. Our objective is to maintain a high level of capital discipline and manage our capital structure to help ensure the Company has sufficient liquidity through all stages of the economic cycle. To ensure financial resilience, Cenovus may, among other actions, adjust capital and operating spending, draw down on our credit facility or repay existing debt, adjust dividends paid to shareholders, purchase our common shares for cancellation, issue new debt, or issue new shares. We also manage our Net Debt to Capitalization ratio to ensure compliance with the associated covenants as defined in our committed credit facility agreement.

As at March 31, 2020, Cenovus's Net Debt to Adjusted EBITDA was 3.1 times. Net Debt to Adjusted EBITDA increased compared with the first quarter of 2019 as result of a weaker Canadian dollar and an increase in our short-term borrowings, as mentioned in the Cash From (Used In) Financing Activities above.

Under the committed credit facility, Cenovus is required to maintain a debt to capitalization ratio not to exceed 65 percent. We are well below this limit at March 31, 2020.

Additional information regarding our financial measures and capital structure can be found in the notes to the interim Consolidated Financial Statements.

Share Capital and Stock-Based Compensation Plans

As at March 31, 2020, there were approximately 1,229 million common shares outstanding (2019 – 1,229 million common shares).

Refer to Note 24 of the interim Consolidated Financial Statements for more details on our Stock Option Plan and our Performance Share Unit, Restricted Share Unit and Deferred Share Unit Plans.

As at March 31, 2020	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares [1]	**1,228,870**	**N/A**
Stock Options	**31,334**	**20,008**
Other Stock-Based Compensation Plans	**21,567**	**1,369**

(1) ConocoPhillips continued to hold 208 million common shares issued as partial consideration related to the Acquisition.

Capital Investment Decisions

As of April 2, 2020, we reduced our planned 2020 capital program by 43 percent, compared with our original budget, to between $750 million and $850 million in order to maintain the strength of our balance sheet in response to the significant decline in world benchmark crude oil prices. Our 2020 capital allocation priorities demonstrate the flexibility in our business plan to reduce capital while we remain focused on committed capital priorities including safe and reliable operations and sustaining and maintenance capital for our existing business operations.

	Three Months Ended March 31,	
($ millions)	**2020**	2019
Adjusted Funds Flow [1]	**(146)**	1,005
Total Capital Investment	**304**	317
Free Funds Flow [1] [2]	**(450)**	688
Cash Dividends	**77**	61
	(527)	627

(1) The comparative period has been reclassified to conform with current period treatment of non-cash inventory write-downs.
(2) Free Funds Flow is a non-GAAP measure defined as Adjusted Funds Flow less capital investment.

We continue to challenge our cost structure and adjusted our discretionary capital plans in 2020, including the suspension of our quarterly cash dividend. This should allow the Company to fund a portion of its revised capital program with debt, internally generated cash flows, cash balance on hand and the prudent use of our balance sheet capacity including draws on our credit lines.

Contractual Obligations and Commitments

Cenovus has obligations for goods and services entered into in the normal course of business. Obligations are primarily related to transportation agreements, our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. Obligations that have original maturities of less than one year are excluded. For further information, see the notes to the March 31, 2020 interim Consolidated Financial Statements and December 31, 2019 Consolidated Financial Statements.

As at March 31, 2020, total commitments were $24 billion, of which $23 billion are for various transportation and storage commitments. Includes transportation commitments of $14 billion (2019 – $13 billion) that are subject to regulatory approval or have been approved, but are not yet in service. Terms are up to 20 years subsequent to the date of commencement and should help align with the Company's future transportation requirements with anticipated production growth.

We continue to focus on mid-term strategies to broaden market access for our crude oil production. We continue to support proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving our crude oil production to market by rail, and assessing options to maximize the value of our crude oil.

As at March 31, 2020, there were outstanding letters of credit aggregating $415 million issued as security for performance under certain contracts (December 31, 2019 – $364 million).

Legal Proceedings

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

Contingent Payment

In connection with the Acquisition and related to our Oil Sands production, we agreed to make quarterly payments to ConocoPhillips during the five years subsequent to May 17, 2017 for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. As at March 31, 2020, the estimated fair value of the contingent payment was $13 million. No amount was payable under the agreement for the first quarter of 2020. See the Corporate and Eliminations section of this MD&A for more details.

RISK MANAGEMENT AND RISK FACTORS

For a full understanding of the risks that impact us, the following discussion should be read in conjunction with the Risk Management and Risk Factors section of our 2019 annual MD&A.

We are exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others are unique to our operations. The impact of any risk or a combination of risks may adversely affect, among other things, Cenovus's business, reputation, financial condition, results of operations and cash flows, which may reduce or restrict our ability to pursue our strategic priorities, respond to changes in our operating environment, pay dividends to our shareholders and fulfill our obligations (including debt servicing requirements) and may materially affect the market price of our securities.

The following provides an update on our risks.

Pandemic Risk

On March 11, 2020 the World Health Organization declared COVID-19 a pandemic indicating the sustained risk of global spread of the disease. Governments and health authorities around the world have implemented a wide variety of measures to reduce the spread of the virus, including travel restrictions, business closures, stay-at-home orders and event cancellations. The effect of these measures has been a significant slow-down in global economic activity that has reduced the demand for crude oil and natural gas products and contributed to a sharp decline in global crude oil and natural gas prices. It is impossible at this point to predict precisely the duration or extent of the impacts of the COVID-19 pandemic on Cenovus's employees, customers, partners and business or when economic activity will normalize.

The COVID-19 pandemic may increase our exposure to, and magnitude of, each of the risks identified in the Risk Management and Risk Factors section of our 2019 annual MD&A that result from a reduction in demand for crude oil and natural gas consumption and/or lower commodity prices. Our business, financial condition, results of operations, cash flows, reputation, access to capital, cost of borrowing, access to liquidity, ability to fund dividend payments and/or business plans may, in particular, without limitation, be adversely impacted as a result of the pandemic and/or decline in commodity prices as a result of:

- The shut-down of facilities or the delay or suspension of work on major capital projects due to workforce disruption or labour shortages caused by workers becoming infected with COVID-19, or government or health authority mandated restrictions on travel by workers or closure of facilities, workforce camps or worksites;
- Suppliers and third-party vendors experiencing similar workforce disruption or being ordered to cease operations;
- Reduced cash flows resulting in less funds from operations being available to fund our capital expenditure budget;

- Reduced commodity prices resulting in a reduction in the volumes and value of our reserves. See "Commodity Prices" below;
- Counterparties being unable to fulfill their contractual obligations to us on a timely basis or at all;
- The inability to deliver products to customers or otherwise get products to market caused by border restrictions, road or port closures or pipeline shut-ins, including as a result of pipeline companies suffering workforce disruptions or otherwise being unable to continue to operate;
- The capabilities of our information technology systems and the potential heightened threat of a cyber-security breach arising from the increased number of employees working remotely; and
- Our ability to obtain additional capital including, but not limited to, debt and equity financing being adversely impacted as a result of unpredictable financial markets, commodity prices and/or a change in market fundamentals.

The extent to which COVID-19 impacts our business, results of operations and financial condition will depend on future developments, which are highly uncertain and are difficult to predict, including, but not limited to, the duration and spread of the pandemic, its severity, the actions to contain COVID-19 or treat its impact, and how quickly and to what extent normal economic and operating conditions can resume and its impacts to our business, results of operations and financial condition which could be more significant in upcoming periods as compared with the first quarter of 2020. Even after the COVID-19 pandemic has subsided, we may continue to experience materially adverse impacts to our business as a result of the pandemic's global economic impact.

There are no comparable recent events that provide guidance as to the effect the spread of COVID-19 as a global pandemic may have, and, as a result, the ultimate impact of the outbreak is highly uncertain and subject to change. Management does not yet know the full extent of the impacts on our business and operations or the global economy as a whole. The situation is changing rapidly and future impacts may materialize that are not yet known.

We are taking proactive steps to protect the health and safety of our staff and the continuity of our business in response to the COVID-19 pandemic. To deter COVID-19 from spreading in any of our workplaces, we have implemented physical distancing measures, including directing the vast majority of our office staff and certain non-essential field staff to work from home. Following the guidance of health officials, mandatory self-quarantine policies, travel restrictions, screening and enhanced cleaning and sanitation measures have been put in place. Our staff have committed to adhering to the new procedures. We also have a comprehensive Business Continuity Plan to ensure continued safe and reliable operations in the event of a COVID-19 outbreak at any of our workplaces.

Excess Crude Oil Supply Risk

In the first quarter, announcements by OPEC and non-OPEC members, including Saudi Arabia and Russia, resulted in a crude oil price dispute and, correspondingly, an increased supply of crude oil in the global energy markets contributing to lower global crude oil prices and overall market volatility. Subsequent to the quarter, OPEC and non-OPEC members, including Saudi Arabia and Russia, agreed to cut crude oil output in May and June, and several other countries announced similar production cuts. However, to date, these crude oil output cuts have failed to substantially lift benchmark oil prices. It is not known how long these conditions will continue, however if the situation continues or worsens (and if it is exacerbated further by the impact of COVID-19) and global crude oil prices remain low for a prolonged period, among other things, our production, project development, profitability, cash flows, ability to access additional capital, and securities trading price could be adversely impacted. See "Commodity Prices".

Commodity Prices

Fluctuations in commodity prices, associated price differentials and refining margins impact our financial condition, results of operations, cash flows, growth, access to capital and cost of borrowing.

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts, market access commitments and generally through our access to committed credit facilities. Financial instruments undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 25 and 26 of the interim Consolidated Financial Statements.

Additionally, the factors discussed under the headings "Pandemic Risk" and "Excess Crude Oil Supply Risk" could continue to negatively impact commodity prices. If crude oil and natural gas prices continue to remain at low levels for an extended period of time, or if the costs of development of our resources significantly increases, the carrying value of our assets may be subject to impairment and our net earnings could be adversely affected. See "Risk Management and Risk Factors – Financial Risks – Commodity Prices" in our 2019 annual MD&A.

Risks Associated with Derivative Financial Instruments

Financial instruments expose us to the risk that a counterparty will default on its contractual obligations. This risk is partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in our *Credit Policy*.

Financial instruments also expose us to the risk of a loss from adverse changes in the market value of financial instruments or if we are unable to fulfill our delivery obligations related to the underlying physical transaction. Financial instruments may limit the benefit to us if commodity prices, interest or foreign exchange rates change. These risks are managed through hedging limits authorized according to our *Market Risk Management Policy*.

Impact of Financial Risk Management Activities

	Three Months Ended March 31,					
	2020			2019		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**25**	**22**	**47**	(12)	230	218
Refining	**(1)**	**-**	**(1)**	(7)	1	(6)
Interest Rate	**-**	**-**	**-**	1	7	8
Foreign Exchange	**5**	**-**	**5**	(1)	(2)	(3)
(Gain) Loss on Risk Management	**29**	**22**	**51**	(19)	236	217
Income Tax Expense (Recovery)	**(8)**	**(5)**	**(13)**	5	(62)	(57)
(Gain) Loss on Risk Management, After Tax	**21**	**17**	**38**	(14)	174	160

In the first quarter of 2020, we incurred realized losses on crude oil risk management activities due to the settlement of benchmark prices relative to our hedging contract prices. Unrealized losses were recorded on our crude oil financial instruments in the first quarter of 2020 primarily due to the realization of settled positions and changes in market prices.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATION UNCERTAINTIES AND ACCOUNTING POLICIES

Management is required to make estimates and assumptions, and use judgment in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further details on the basis of preparation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements.

Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in our annual and interim Consolidated Financial Statements.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised.

The full extent of the impact of COVID-19 on our operations and future financial performance is currently unknown. It will depend on future developments that are uncertain and unpredictable, including the duration and spread of COVID-19, its continued impact on capital and financial markets on a macro-scale and any new information that may emerge concerning the severity of the virus. These uncertainties may persist beyond when it is determined how to contain the virus or treat its impact. The outbreak presents uncertainty and risk with respect to the Company, its performance, and estimates and assumptions used by Management in the preparation of its financial results.

A full list of the key sources of estimation uncertainty can be found in our annual Consolidated Financial Statements for the year ended December 31, 2019. The outbreak and current market conditions have increased the complexity of estimates and assumptions used to prepare Consolidated Financial Statements, particularly related to the following key sources of estimation uncertainty:

- ***Recoverable Amounts***

  Determining the recoverable amount of a CGU or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. The severe drop in commodity prices due to reasons noted above, have increased the risk of measurement uncertainty in determining the recoverable amounts, especially estimating economic crude oil and natural gas reserves and estimating forward commodity prices.

- ***Decommissioning Costs***

  Provisions are recorded for the future decommissioning and restoration of our upstream assets, refining assets and crude-by-rail terminal at the end of their economic lives. Management uses judgment to assess the existence and to estimate the future liability and uses a credit-adjusted discount rate to present value the estimated future cash flows required to settle the obligation. Market volatility at March 31, 2020 increased the measurement uncertainty inherent in determining the appropriate credit-adjusted discount rate that is used in the estimation of decommissioning liabilities.

- ***Income Tax Provisions***

  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. In the current economic environment, the expected total annual earnings or expected earnings is subject to measurement uncertainty.

Changes to these assumptions could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Changes in Accounting Policies

There were no new or amended accounting standards or interpretations adopted during the three months ended March 31, 2020.

New Accounting Standards and Interpretations not yet Adopted

A number of new standards, amendments to accounting standards and interpretations were effective beginning on or after January 1, 2020. There were no new or amended accounting standards or interpretations issued during the three months ended March 31, 2020 that are expected to have a material impact on our interim Consolidated Financial Statements.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the three months ended March 31, 2020 that have materially affected, or are reasonably likely to materially affect ICFR.

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

OUTLOOK

We expect the remainder of 2020 to be a challenging time for our industry and the global economy in general. With the uncertainty around the COVID-19 pandemic and the oversupply and high storage levels of crude oil which resulted from the dispute between Saudi Arabia and Russia, we anticipate prices may remain very low throughout 2020. We would anticipate that the demand for refined products will be an early indicator of recovery from the impact of COVID-19. To maintain the strength of our balance sheet, we have revised our 2020 budget, reducing capital spending plans and suspending other initiatives. We have ample liquidity, top-tier assets, one of the lowest cost structures in the industry and have demonstrated our ability to reduce discretionary capital, which should allow us to weather these challenges. Our top priority will be to maintain the strength of our balance sheet.

As a result of our decision to temporarily suspend our crude-by-rail program, we are unable to make use of curtailment relief under the SPA program; therefore, our Oil Sands production will be restricted by our own voluntary production reductions or the government mandated production curtailments. Over the long-term, transportation challenges will continue to negatively impact heavy oil prices, demonstrating the need for approved pipeline projects to proceed as soon as possible. Current low crude oil prices may ease transportation constraints temporarily as producers reduce uneconomic production. We expect our annual Oil Sands production to average between 350,000 barrels per day and 400,000 barrels per day.

We continue to look for additional opportunities to reduce operating, capital, and G&A spending and increase our margins through strong operating performance and cost leadership, while focusing on safe and reliable operations. Proactively managing our market access commitments and opportunities assists with our goal of reaching a broader customer base to secure a higher sales price for our crude oil.

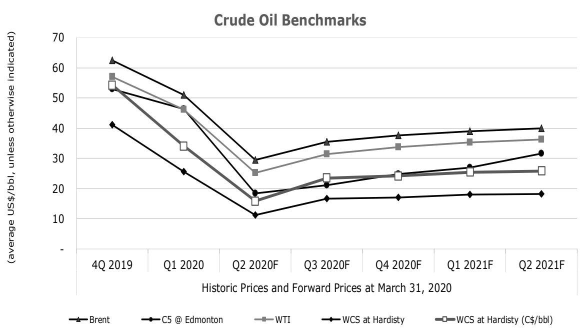
The following outlook commentary is focused on the next twelve months.

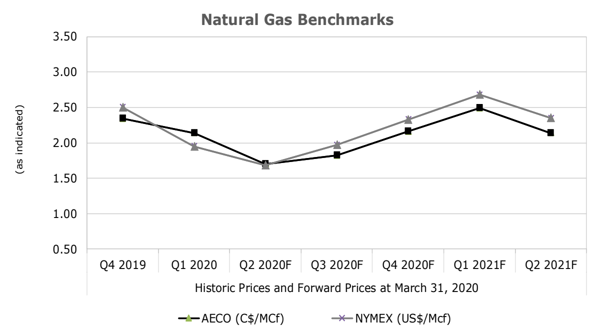
Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for light crude oil prices will be tied primarily to the supply response to the current uncertain price environment, the impact of oversupply, and global demand impacts amid COVID-19 concerns;
- Crude oil price volatility is expected to continue due to significant crude demand destruction as a result of COVID-19 and the oversupply that was driven by the battle for market share between Saudi Arabia and Russia;
- Continuing agreement between OPEC and non-OPEC members to maintain crude oil production cuts to support crude oil prices;
- We expect that the WTI-WCS differential in Alberta will remain largely tied to the extent to which voluntary economically driven supply cuts are made, production curtailments in Alberta remain in place, the potential start-up of Enbridge Inc.’s Line 3 Replacement Program, the completion of the Trans Mountain Expansion and Keystone XL projects, and the level of crude-by-rail activity; and
- Significantly reduced refined products demand due to COVID-19 will likely weaken refining crack spreads in 2020 relative to previous years. Refining crack spreads will continue to fluctuate, adjusting for seasonal trends, and refining run cuts in North America.

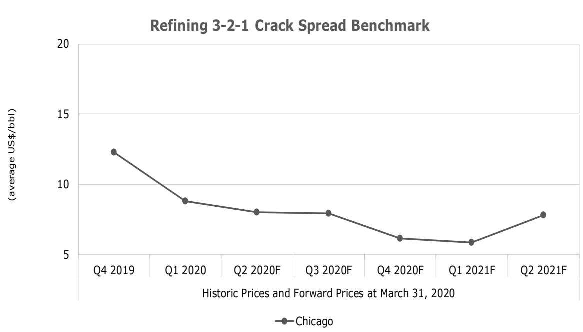
Natural gas and NGLs production associated with our Conventional assets provide improved upstream integration for the fuel, solvent and blending requirements at our Oil Sands operations.

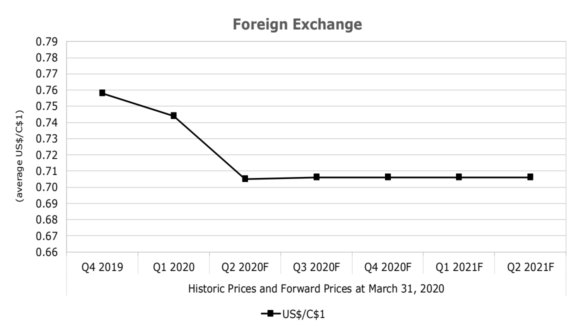




Natural gas prices are anticipated to remain challenged due to weaker demand as a result of COVID-19, partially offset by reduced North American production. AECO hub pricing is expected to remain lower than NYMEX, reflecting transportation costs.

We expect the Canadian dollar to continue to be tied to crude oil prices, the pace at which the U.S. Federal Reserve Board and the Bank of Canada raise or lower benchmark lending rates relative to each other, and emerging macro-economic factors. The Bank of Canada lowered its benchmark lending rate twice in the first quarter of 2020 to address the impacts of COVID-19.





Our exposure to light-heavy crude oil price differentials is composed of both a global light-heavy component as well as Canadian transportation constraints. While we expect to see volatility in crude oil prices, we have the ability to partially mitigate the impact of light-heavy crude oil price differentials through the following:

- Transportation commitments and arrangements – supporting transportation projects that move crude oil from our production areas to consuming markets, including tidewater markets;

- Integration – having heavy oil refining capacity capable of processing Canadian heavy oil. From a value perspective, our refining business positions us to capture value from both the WTI-WCS differential for Canadian crude oil and the Brent-WTI differential from the sale of refined products;
- Marketing agreements – limiting the impact of fluctuations in upstream crude oil prices by entering into physical supply transactions with fixed price components directly with refiners;
- Dynamic storage – our ability to use the significant storage capacity in our oil sands reservoirs provides us flexibility on timing of production and sales of our inventory. We will continue to manage our production well rates in response to pipeline capacity constraints, mandated production curtailments and crude oil price differentials; and
- Financial hedge transactions – limiting the impact of fluctuations in upstream crude oil prices by entering into financial transactions related to our exposures.

Key Priorities For 2020

In the current commodity price environment, we continue to focus on maintaining balance sheet strength and liquidity. Enhancing our financial resilience and flexibility while continuing to deliver safe and reliable operations will continue to be a top priority during these uncertain times.

Our corporate strategy remains unchanged, focused on maximizing shareholder value through cost leadership and realizing the best margins for our products. We expect to remain disciplined with our capital investment, focus on improving market access, and maintaining cost leadership to achieve margin improvement and environmental benefits.

Maintain Financial Resilience

We have top-tier assets, one of the lowest cost structures in our industry and a strong balance sheet, which positions us to withstand the challenges of the current market environment. Our capital planning process is flexible and spending can be reduced in response to commodity prices and other economic factors so we can maintain our financial resilience. Our financial framework and flexible business plan allow multiple options to manage our balance sheet. We will continue to assess our spending plans on a regular basis while closely monitoring crude oil prices in 2020.

Disciplined Capital Investment

As a result of the collapse of oil prices and COVID-19, we updated our 2020 guidance effective April 1, 2020. We anticipate capital investment to be between $750 million and $850 million, the majority of which will be directed towards sustaining oil sands production and refining operations. In 2020, we will continue to be disciplined with our capital. Our Oil Sands production is expected to range between 350,000 and 400,000 barrels per day for the remainder of 2020.

As at March 31, 2020, our Net Debt position was $7.4 billion. We expect to fund our near-term cash requirements through prudent use of our balance sheet capacity including draws on our credit and demand facilities, management of our asset portfolio and other corporate and financial opportunities that may be available to us. We remain committed to maintaining our investment grade credit ratings at S&P Global Ratings and DBRS Limited and re-establishing investment grade ratings at Moody’s and Fitch. Through a combination of cash on hand and available capacity on our committed credit facilities and demand facilities, we have approximately $5.9 billion of liquidity. We expect to increase our debt as we manage through the low commodity price environment.

Shareholder Returns

Cenovus had based its ability to provide a sustainable dividend from free funds flow taking into consideration balance sheet strength and based on a WTI price environment of US$45.00 per barrel. In the context of recent commodity price forecasts and economic, market and business conditions in the oil and gas industry, we have temporarily suspended our quarterly dividend.

Market Access

Market access constraints for Canadian crude oil production continue to be a challenge. Our strategy is to maintain firm transportation commitments through a combination of pipelines, rail and marine. We expect to supplement firm capacity with active blending, storage, sourcing and destination optimization to ensure we are maximizing the margin on every barrel we produce.

Cost Leadership

On April 1, 2020 we updated our guidance from December 2019. We reduced our planned 2020 capital investment as mentioned above and are forecasting operating cost reductions of about $100 million and G&A cost reductions of about $50 million compared with the initial December 2019 budget. We will continue to look for ways to improve efficiencies across Cenovus to drive incremental capital, operating and G&A cost reductions.

ADVISORY

Oil and Gas Information

The estimates of reserves were prepared effective December 31, 2019 by independent qualified reserves evaluators ("IQREs"), based on the COGE Handbook and in compliance with the requirements of NI 51-101. Estimates are presented using an average of three IQREs January 1, 2020 price forecasts. For additional information about our reserves and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our AIF for the year ended December 31, 2019.

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 (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 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 document contains certain forward-looking statements and forward-looking information (collectively referred to as "forward-looking information") within the meaning of applicable securities legislation, including the *U.S. Private Securities Litigation Reform Act of 1995*, about our current expectations, estimates and projections about the future, based on certain assumptions made by us in light of our experience and perception of historical trends. Although we believe that the expectations represented by such forward looking information are reasonable, there can be no assurance that such expectations will prove to be correct.

Forward-looking information in this document is identified by words such as "aim", "anticipate", "believe", "can be", "capacity", "committed", "commitment", "continuing", "could", "drive", "ensure", "estimate", "expect", "focus", "forecast", "forward", "future", "guidance", "maintain", "may", "objective", "outlook", "plan", "position", "potential", "priority", "projection", "re-establishing", "strategy", "should", "target", "will", or similar expressions and includes suggestions of future outcomes, including statements about: strategy and related milestones; schedules and plans; focus on maximizing shareholder value through cost leadership; desire to realize the best margins for our products; maintaining liquidity and preserving a resilient balance sheet by reducing spending, while maintaining safe and reliable operations; ample and continued liquidity and runway to sustain operations through a prolonged market downturn; evaluating disciplined investment in our portfolio against dividends, share repurchases and achieving and maintaining the optimal debt levels while targeting investment grade status; maintaining a high level of capital discipline and managing our capital structure to help ensure the Company has sufficient liquidity through all stages of the economic cycle; demand for refined product being an early indicator of recovery from the impact of COVID-19; continuing to advance our operational performance and upholding our trusted reputation; focusing on sustainably growing shareholder returns and further reducing Net Debt as well as continuing to integrate ESG considerations into our business plan; expected timing for oil sands expansion phases projections for 2020 and future years and our plans and strategies to realize such projections; forecast exchange rates and trends; future opportunities for oil and natural gas development; forecast operating and financial results, including forecast sales prices, costs and cash flows; our ability to satisfy payment obligations as they become due; priorities for and approach to capital investment decisions or capital allocation; planned capital expenditures, including the amount, timing and funding sources thereof; all statements with respect to our 2020 guidance estimates; expected future production, including the timing, stability or growth thereof; our ability to manage our production well rates in response to pipeline capacity constraints, mandated production curtailments and crude oil price differentials; the impact of the Government of Alberta's mandatory production curtailment; our ability to take steps to partially mitigate against wider WTI and WCS price differentials; our expectation that the WTI-WCS differential in Alberta will remain largely tied to the extent to which voluntary economically driven supply cuts are made, production curtailments in Alberta remain in place, the potential start-up Enbridge Inc.'s Line 3 Replacement Program, the completion of Trans Mountain Expansion and Keystone XL projects, and the level of crude-by-rail activity; our expectation that our capital investment will be funded through prudent use of our balance sheet capacity including draws on our credit and demand facilities, management of our asset portfolio and other corporate and financial opportunities that may be available to us; our expectation to increase our debt as we manage through the low commodity price environment; expected reserves; impact on alignment of transportation and storage commitments and production growth; all statements related to government royalty regimes applicable to Cenovus, which regimes are subject to change; our ability to preserve our financial resilience and various plans and strategies with respect thereto; forecast cost reductions and sustainability thereof; our priorities, including for 2020; future impact of regulatory measures; forecast commodity prices, differentials and trends and expected impact; potential impacts of various risks, including those related to commodity prices and climate change; the potential effectiveness of our risk management strategies; new accounting standards, the timing for the adoption thereof, and anticipated impact on the Consolidated Financial Statements; the availability and repayment of our credit facilities; potential asset sales; expected impacts of the contingent payment; future investment, use and development of technology and equipment and associated future outcomes; our ability to access and implement all technology necessary to efficiently and effectively operate our assets and achieve expected future results; planned capital expenditures; and projected growth and projected shareholder return. 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 our forward-looking information is based include, but are not limited to: forecast oil and natural gas, natural gas liquids, condensate and refined products prices, light-heavy crude oil price differentials and other assumptions identified in Cenovus's 2020 guidance, available at cenovus.com; bottom of the cycle commodity prices of about US$45/bbl WTI and C$44/bbl WCS in a normalized demand market; our forecast production volumes are subject to potential further ramp down of production based on business and market conditions; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; achievement of further cost reductions and sustainability thereof; applicable royalty regimes, including expected royalty rates; future improvements in availability of product transportation capacity; increase to our share price and market capitalization over the long term; opportunities to repurchase shares for cancellation at prices acceptable to us; cash flows, cash balances on hand and access to credit and demand facilities being sufficient to fund capital investments; foreign exchange rate, including with respect to our US$ debt and refining capital and operating expenses; our ability to reduce our 2020 oil sands production, including without negative impacts to our assets; realization of expected capacity to store within our oil sands reservoirs barrels not yet produced, including that we will be able to time production and sales of our inventory at later dates when demand has increased, pipeline capacity has improved and crude oil differentials have narrowed; the Government of Alberta's mandatory production curtailment will continue to maintain narrow the differential between WTI and WCS crude oil prices thereby positively impacting cash flows for Cenovus; the WTI-WCS differential in Alberta remains largely tied to the extent to which voluntary economically driven supply cuts are made, production curtailments in Alberta remain in place, the potential start-up of Enbridge Inc.'s Line 3 Replacement Program, the completion of Trans Mountain Expansion and Keystone XL projects, and the level of crude-by-rail activity; the ability of our refining capacity, dynamic storage, existing pipeline commitments, financial hedge transactions to partially mitigate a portion of our WCS crude oil volumes against wider differentials; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; accounting estimates and judgments; future use and development of technology and associated expected future results; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow to meet our current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; our ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; our ability to access sufficient capital to pursue our development plans; our ability to complete asset sales, including with desired transaction metrics and within the timelines we expect; forecast inflation and other assumptions inherent in our current guidance set out below; expected impacts of the contingent payment to ConocoPhillips; alignment of realized WCS and WCS prices used to calculate the contingent payment to ConocoPhillips; our ability to access and implement all technology and equipment necessary to achieve expected future results and that such results are realized; our ability to implement capital projects or stages thereof in a successful and timely manner; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2020 guidance, as updated April 1, 2020, assumes: Brent prices of US$39.00/bbl, WTI prices of US$34.00/bbl; WCS of US$18.50/bbl; Differential WTI-WCS of US$15.50/bbl; AECO natural gas prices of $2.00/Mcf; Chicago 3-2-1 crack spread of US$8.30/bbl; and an exchange rate of $0.70 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially, include, but are not limited to: our ability to access or implement some or all of the technology necessary to efficiently and effectively operate our assets and achieve expected future results; volatility of and other assumptions regarding commodity prices; the duration of the market downturn; our continued liquidity is sufficient to sustain operations through a prolonged market downturn; WTI-WCS differential in Alberta does not remain largely tied to the extent to which voluntary economically driven supply cuts are made, production curtailments in Alberta remain in place, the potential start-up of Enbridge Inc.'s Line 3 Replacement Program, the completion of Trans Mountain Expansion and Keystone XL projects, and the level of crude-by-rail activity; our ability to realize the expected impacts of our capacity to store within our oil sands reservoirs barrels not yet produced, including possible inability to time production and sales at later dates when pipeline capacity and crude oil differentials have improved; failure of the Government of Alberta's mandatory production curtailment to cause the differential between the WTI and the WCS crude oil prices to narrow or to narrow sufficiently to positively impact our cash flows; unexpected consequences related to the Government of Alberta's mandatory production curtailment; the Government of Alberta may extend mandatory production curtailment beyond when takeaway capacity constraints have been sufficiently relieved; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our liquidity position; the accuracy of cost estimates regarding commodity prices, currency and interest rates; lack of alignment of realized WCS prices and WCS prices used to calculate the contingent payment to ConocoPhillips; product supply and demand; accuracy of our share price and market capitalization assumptions; market competition, including from alternative energy sources; risks inherent in our 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 the operation of our crude-by-rail terminal, including health, safety and environmental risks; our ability to maintain desirable ratios of Net Debt to Adjusted EBITDA as well as Net Debt to Capitalization; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; our ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to us or any of our securities; changes to our dividend plans; our ability to utilize tax losses in the future; accuracy of our reserves, future production and future net revenue estimates; accuracy of our accounting estimates and judgements; our ability to replace and expand oil and gas reserves; potential requirements under applicable accounting standards for impairment or reversal of estimated recoverable amounts of some or all of our assets or goodwill from time to time; our ability to maintain our relationship with our partners and to successfully manage and operate our integrated business; reliability of our assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events such as fires, severe weather conditions, pandemics, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; cost escalations, including inflationary pressures on operating costs, including labour, materials, natural gas and other energy sources used in oil sands processes and increased insurance deductibles or premiums; potential failure of products to achieve or maintain acceptance in the market; risks associated with fossil fuel industry reputation and litigation related thereto; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of bitumen and/or crude oil into petroleum and chemical products; risks associated with technology and equipment and its application to our business, including potential cyberattacks; risks associated with climate change and our assumptions relating thereto; the timing and the costs of well and pipeline construction; our ability to secure adequate and cost effective product transportation including sufficient pipeline, crude-by-rail, marine or alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and our ability to attract and retain, critical talent; possible failure to obtain and retain qualified staff and equipment in a timely and cost efficient manner; changes in labour relationships; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon, climate change and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our Consolidated Financial Statements; changes in general economic, market and business conditions; the impact of production agreements among OPEC and non-OPEC members; the political and economic conditions in the countries in which we operate or supply; the occurrence of unexpected events such as pandemics, war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits, shareholder proposals and regulatory actions against us.

Statements relating to "reserves" are deemed to be forward looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward-looking information. For a full discussion of our material risk factors, see "Risk Management and Risk Factors" in this MD&A.

ABBREVIATIONS

The following abbreviations have been used in this document:

Crude Oil		**Natural Gas**	
bbl	barrel	Mcf	thousand cubic feet
Mbbls/d	thousand barrels per day	MMcf	million cubic feet
MMbbls	million barrels	Bcf	billion cubic feet
BOE	barrel of oil equivalent	MMBtu	million British thermal units
MMBOE	million barrel of oil equivalent	GJ	gigajoule
WTI	West Texas Intermediate	AECO	Alberta Energy Company
WCS	Western Canadian Select	NYMEX	New York Mercantile Exchange
CDB	Christina Dilbit Blend		
MSW	Mixed Sweet Blend		
WTS	West Texas Sour		

NETBACK RECONCILIATIONS

The following tables provide a reconciliation of the items comprising Netbacks to Operating Margin found in our interim Consolidated Financial Statements.

Total Production

Upstream Financial Results

	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Three Months Ended March 31, 2020 ($ millions)	Oil Sands[1]	Conventional[1] [2]	Total	Condensate	Inventory	Internal Usage[3]	Other	Total Upstream
Gross Sales	2,027	162	2,189	(1,213)	-	(68)	(16)	892
Royalties	44	3	47	-	-	-	-	47
Transportation and Blending	1,604	23	1,627	(1,213)	-	-	(1)	413
Operating	285	84	369	-	-	(68)	(10)	291
Inventory Write-Downs	335	-	335		(335)			-
Netback	(241)	52	(189)	-	335	-	(5)	141
(Gain) Loss on Risk Management	25	-	25	-	-	-	-	25
Operating Margin	(266)	52	(214)	-	335	-	(5)	116

	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Three Months Ended March 31, 2019 ($ millions)	Oil Sands[1]	Conventional[1] [2]	Total	Condensate	Inventory	Internal Usage[3]	Other	Total Upstream
Gross Sales	2,427	220	2,647	(946)	-	(80)	(19)	1,602
Royalties	177	14	191	-	-	-	-	191
Transportation and Blending	1,147	19	1,166	(946)	-	-	-	220
Operating	274	93	367	-	-	(80)	(10)	277
Netback	829	94	923	-	-	-	(9)	914
(Gain) Loss on Risk Management	(12)	-	(12)	-	-	-	-	(12)
Operating Margin	841	94	935	-	-	-	(9)	926

(1) Found in Note 1 of the Interim Consolidated Financial Statements.
(2) This segment was previously referred to as the Deep Basin segment.
(3) Represents natural gas volumes produced by the Conventional segment used for internal consumption by the Oil Sands segment.

Oil Sands

	Basis of Netback Calculation				Adjustments			Per Interim Consolidated Financial Statements[1]
Three Months Ended March 31, 2020 ($ millions)	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	417	393	810	-	1,213	-	4	2,027
Royalties	23	21	44	-	-	-	-	44
Transportation and Blending	221	170	391	-	1,213	-	-	1,604
Operating	143	138	281	-	-	-	4	285
Inventory Write-Downs	-	-	-			335		335
Netback	30	64	94	-	-	(335)	-	(241)
(Gain) Loss on Risk Management	9	16	25	-	-	-	-	25
Operating Margin	21	48	69	-	-	(335)	-	(266)

	Basis of Netback Calculation				Adjustments			Per Interim Consolidated Financial Statements[1]
Three Months Ended March 31, 2019 ($ millions)	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	722	755	1,477	-	946	-	4	2,427
Royalties	61	116	177	-	-	-	-	177
Transportation and Blending	130	71	201	-	946	-	-	1,147
Operating	146	124	270	-	-	-	4	274
Netback	385	444	829	-	-	-	-	829
(Gain) Loss on Risk Management	(5)	(7)	(12)	-	-	-	-	(12)
Operating Margin	390	451	841	-	-	-	-	841

(1) Found in Note 1 of the Interim Consolidated Financial Statements.

Conventional [1]

Three Months Ended March 31, 2020 ($ millions)	Basis of Netback Calculation Total	Adjustments Other[3]	Per Interim Consolidated Financial Statements[2] Total Conventional
Gross Sales	**150**	**12**	**162**
Royalties	**3**	**-**	**3**
Transportation and Blending	**22**	**1**	**23**
Operating	**78**	**6**	**84**
Netback	**47**	**5**	**52**
(Gain) Loss on Risk Management	**-**	**-**	**-**
Operating Margin	**47**	**5**	**52**

Three Months Ended March 31, 2019 ($ millions)	Basis of Netback Calculation Total	Adjustments Other[3]	Per Interim Consolidated Financial Statements[2] Total Conventional
Gross Sales	205	15	220
Royalties	14	-	14
Transportation and Blending	19	-	19
Operating	87	6	93
Netback	85	9	94
(Gain) Loss on Risk Management	-	-	-
Operating Margin	85	9	94

(1) This segment was previously referred to as the Deep Basin segment.
(2) Found in Note 1 of the interim Consolidated Financial Statements.
(3) Reflects operating margin from processing facility.

The following table provides the sales volumes used to calculate Netback.

Sales Volumes

(barrels per day, unless otherwise stated)	Three Months Ended March 31, 2020	2019
Oil Sands		
Foster Creek	**169,207**	154,369
Christina Lake	**228,764**	176,079
Total Oil Sands (BOE per day)	**397,971**	330,448
Conventional		
Total Liquids	**29,766**	28,003
Natural Gas (MMcf per day)	**395**	458
Total Conventional (BOE per day)	**95,558**	104,290
Sales before Internal Consumption	**493,529**	434,738
Less: Internal Consumption [4] (MMcf per day)	**(346)**	(320)
Total Sales [4] (BOE per day)	**435,880**	381,444

(4) Less natural gas volumes used for internal consumption by the Oil Sands segment.