MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE PERIOD ENDED SEPTEMBER 30, 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 October 28, 2020, should be read in conjunction with our September 30, 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 October 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 interim 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 472,000 BOE per day for the three months ended September 30, 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 382,000 gross barrels per day of crude oil feedstock into an average of 397,000 gross barrels per day of refined products in the three months ended September 30, 2020.

For a description of our operations, refer to the Reportable Segments section of this MD&A.

On October 25, 2020, Cenovus and Husky Energy Inc. ("Husky") announced that they have entered into a definitive agreement to combine the two companies in an all-stock transaction to create a new integrated Canadian oil and natural gas company (the "Husky Transaction"). Upon completion of the Husky Transaction, which will require shareholder and regulatory approval, the combined entity will operate as Cenovus and trade under the Cenovus name and remain headquartered in Calgary, Alberta.

Our Strategy

Our overall strategy remains 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. 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, there was significant crude oil demand reduction as a result of measures taken by governments around the world to contain the COVID-19 pandemic. At the same time, overall global crude oil supply increased as efforts 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. The combination of these events resulted in a collapse of crude oil benchmark prices, dropping to US$10.01 per barrel, excluding a historic one-day low of negative US$37.63 per barrel on April 20, 2020.

In April, the agreement between OPEC and a group of 10 non-OPEC members (collectively, "OPEC+") to cut crude oil output, and several other countries announcing similar production cuts decreased the global supply of crude oil. At the same time, as governments began to ease off on some of the measures taken to contain the pandemic there was an increase in demand for crude oil which helped increase crude oil prices. During the third quarter, crude oil prices improved from the second quarter, however prices continued to be volatile due to market responses to COVID-19 and OPEC crude oil production output decisions. The duration of the current lower commodity price environment continues to be uncertain, especially with the second wave of COVID-19 infections driving concerns.

We believe our reduced 2020 capital investment plan, operating cost reductions and general and administrative ("G&A") reductions, announced on April 2, 2020, enhances our financial resilience and financial capability to maintain our base business and to deliver safe and reliable operations. We will continue to challenge our cost structure in the face of these unprecedented conditions.

The Company has available $5.6 billion in committed credit facilities, with $1.1 billion maturing in April 2021, $1.2 billion maturing in late 2022, and $3.3 billion maturing in late 2023. A further $1.6 billion of uncommitted demand lines to issue letters of credit or in some cases draw up to $600 million for general purposes are available, and the Company has no bond maturities until late 2022. We believe that we have ample liquidity and runway to sustain our operations through a prolonged market downturn. Under the terms of Cenovus's committed credit facilities, the Company is required to maintain a debt to capitalization ratio, as defined in the agreement, not to exceed 65 percent. As at September 30, 2020, the Company was well below this limit.

The Provincial and Federal governments have recognized the serious economic impacts of the spread of COVID-19 and have taken steps to provide various programs, such as the Canada Emergency Wage Subsidy ("CEWS") program. During the third quarter we continued to benefit from the assistance of the CEWS program to help protect jobs during the pandemic.

The Company remains committed to the health and safety of its workforce and the public while providing essential services. Physical distancing measures continue to be taken to maintain the health and safety of our people and to help prevent the spread of COVID-19. We continue to monitor the changing COVID-19 situation. Earlier this month we lifted our mandatory work from home measure to open our modified workspaces in the Calgary offices to staff again, with workplace safety plans and protocols in place. Increases in staff levels at sites and offices has been and will continue to be achieved in accordance with guidance received from the Federal and Provincial governments and public health officials.

QUARTERLY OVERVIEW

Crude oil demand, which continues to be negatively impacted by the effects of COVID-19, showed signs of gradual recovery throughout the summer months with the easing of some of the restrictions imposed by governments to limit the spread of the virus combined with the commitment by OPEC and non-OPEC members to reduce crude oil production levels in response to lower demand and low prices. COVID-19 infection rates, global economic performance and political development will continue to impact the pace of demand recovery.

Brent and WTI crude oil benchmark prices averaged US$43.37 per barrel and US$40.93 per barrel, respectively, for the third quarter. Average crude oil prices have improved significantly from the very low levels in the second quarter (Brent – US$33.27 per barrel; WTI – US$27.85 per barrel), as the market stabilized and the volatility in prices decreased. Even with the improvement, crude oil benchmark prices remain more than 25 percent lower than the third quarter of last year. Western Canadian Select ("WCS") benchmark prices rose 94 percent from an average low of US$16.38 per barrel in the second quarter to an average of US$31.84 per barrel in the third quarter. However, the average WCS benchmark crude oil prices fell along with the entire crude market, averaging 28 percent lower than US$44.21 per barrel in the same period of 2019. The impact of falling crude prices was partially offset by a narrower differential between WTI and WCS as industry-wide production shut-ins resulted in excess pipeline capacity.

Operationally, our upstream assets performed well. We continued to deliver good health and safety performance in light of the health and wellness challenges presented to staff by the pandemic. In response to increasing crude oil prices we accessed additional production curtailment credits available in the market, which allowed us to produce above our curtailment limit. Our upstream production in the quarter averaged 471,799 BOE per day, five percent higher than the third quarter of 2019, when production was in line with the Government of Alberta's mandatory production curtailment restrictions. The increase was partially offset by planned turnaround and maintenance activities in the third quarter of 2020. Sales volumes in the quarter were higher than the second quarter as we sold crude oil inventory that had built up from April through June, when the average WTI prices were significantly lower (April – US$16.70 per barrel, May – US$28.53 per barrel and June – US$38.31 per barrel), in July when the average WTI price was US$40.77 per barrel. When the decision was made to store barrels due to those low crude oil prices, we entered into risk management contracts to fix the margin we would receive in the future periods. Although risk management losses were realized, as settlement prices were higher than the contract prices, the corresponding increase in the sales price for the barrels of crude oil offset that and we were able to lock in an improved margin as a result of our decision to store in low pricing months and sell in future periods when prices were higher.

Our Wood River and Borger refineries (the "Refineries") demonstrated reliable operational performance while continuing to operate below capacity due to economic crude rate reductions in response to lower refined product demand and weak pricing as a result of COVID-19.

Upstream operating margin of $668 million in the third quarter increased to more than four times that of $157 million in the second quarter due to higher average realized crude oil sales price and higher sales volumes, partially offset by increased transportation and blending costs and higher royalties. Upstream operating margin in the third quarter of 2020 decreased compared with $954 million in 2019, due to a lower average realized crude oil sales price and realized risk management losses compared with gains in 2019, partially offset by higher sales volumes and lower royalties.

Our average realized crude oil sales price of $39.77 per barrel increased significantly compared with $12.83 per barrel in the second quarter due to the improved crude oil prices. However, our average realized crude oil sales price was lower compared with $55.13 per barrel in the third quarter of 2019 reflecting the declining benchmark WTI prices, partially offset by the narrower WTI-WCS differential and lower priced condensate used for blending.

Operating margin for our Refining and Marketing segment was negative $74 million in the third quarter, a decline of $208 million from the second quarter. Refining and Marketing operating margin decreased $200 million compared with the third quarter of 2019 primarily due to decreased market crack spreads, reduced crude oil runs and lower crude advantage, partially offset by lower operating costs.

In the third quarter of 2020, we:

- Continued our safe and reliable operating performance;
- Demonstrated our ability to use our full suite of assets to maximize prices received for every barrel as we managed to store volumes in a low-price environment and cleared inventory when we could obtain higher prices;
- Increased our Oil Sands production rates to 385,937 barrels per day, responding to the higher crude oil benchmark prices, while managing to reduce the non-fuel per-unit operating costs. Overall, per-unit operating costs increased nine percent to $7.53 per barrel compared with $6.90 per barrel in the third quarter of 2019 due to higher natural gas prices;
- Recognized an impairment charge of $450 million for the Borger cash generating unit ("CGU"), as additional depreciation, depletion and amortization expense;
- Recorded Cash from Operating Activities of $732 million compared with Cash used in Operating Activities of $834 million in the second quarter of 2020 (2019 – Cash from Operating Activities of $834 million);
- Achieved Adjusted Funds Flow of $414 million compared with a deficit of $462 million in the second quarter of 2020 (2019 – Adjusted Funds Flow of $928 million);
- Reduced Net Debt to $7.5 billion and total debt to $7.9 billion from the second quarter of 2020, driven by Free Funds Flow of $266 million;
- Used the proceeds from the issuance of US$1.0 billion in 5.375 percent senior unsecured notes due in 2025 to repay $1.4 billion of borrowings on our committed credit facility; and
- Recorded a Net Loss of $194 million compared with Net Earnings of $187 million in 2019.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2020	**Percent Change**	2019	**2020**	**Percent Change**	2019
Upstream Production Volumes						
Oil Sands (barrels per day)						
Foster Creek	**164,954**	**5**	156,527	**164,935**	**4**	158,888
Christina Lake	**220,983**	**12**	198,068	**217,133**	**15**	188,671
	385,937	**9**	354,595	**382,068**	**10**	347,559
Conventional [1] (BOE per day)	**85,862**	**(9)**	93,901	**91,196**	**(8)**	98,807
Total Production (BOE per day)	**471,799**	**5**	448,496	**473,264**	**6**	446,366
Sales [2] (BOE per day)	**428,659**	**8**	398,304	**423,677**	**9**	388,237
Refining and Marketing						
Crude Oil Runs [3] (Mbbls/d)	**382**	**(18)**	465	**383**	**(13)**	438
Refined Product [3] (Mbbls/d)	**397**	**(18)**	485	**396**	**(14)**	463
Crude Utilization [3] (percent)	**77**	**(19)**	96	**77**	**(14)**	91
Crude-by-Rail (barrels per day)						
Crude-by-Rail Loads [4]	**-**	**(100)**	68,380	**33,780**	**(13)**	38,765
Crude-by-Rail Sales [5]	**-**	**(100)**	62,789	**40,293**	**11**	36,212

(1) This segment was previously referred to as the Deep Basin segment.
(2) Less natural gas volumes used for internal consumption by the Oil Sands segment.
(3) Represents 100 percent of the Wood River and Borger refinery operations. Cenovus's interest is 50 percent.
(4) Represents volumes transported outside of Alberta.
(5) Represents volumes sold outside of Alberta.

Upstream Production Volumes

Oil Sands production for the three and nine months ended September 30, 2020 reflects increased production above our curtailment limit achieved by purchasing additional production curtailment credits compared with 2019, where production was in line with the Government of Alberta's mandatory production curtailment program. In the third quarter of 2020, production was reduced by 8,528 barrels per day due to a planned turnaround and maintenance at Christina Lake, which began late September and ran until mid-October 2020, and planned maintenance at Foster Creek. In 2019, production was impacted by a planned turnaround at Christina Lake during the second quarter of 2019.

Conventional production in the three months ended September 30, 2020 decreased compared with the third quarter of 2019, due to natural well declines and downtime due to a planned turnaround at a non-operated natural gas plant in the Elmworth-Wapiti area, partially offset by Marten Hills heavy oil production starting in 2020. In the third quarter of 2019, production was impacted by temporary shut-ins from low natural gas prices. Production in the nine months ended September 30, 2020 decreased due to natural well declines, partially offset by Marten Hills heavy oil production, as well as fewer shut-ins for low commodity pricing.

Refining and Marketing

Crude oil runs and refined product output decreased in the third quarter and on a year-to-date basis compared with the same periods in 2019 as both Refineries implemented crude rate reductions in response to reduced demand and weak pricing for refined products as a result of COVID-19. In 2019, both Refineries were impacted by planned turnarounds and unplanned maintenance. For the three and nine months ended September 30, 2020, the economic crude rate reductions had a greater impact than planned and unplanned maintenance in 2019.

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

In 2020, the impact of market factors such as falling crude oil prices, lower refining throughput as a result of low market crack spreads, and volatile blending costs were the primary drivers of our financial results. The following key performance measures are discussed in more detail within this MD&A.

($ millions, except per share amounts)	Nine Months Ended September 30,		2020			2019				2018 [1] [2]	
	2020	2019	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Revenues	**9,801**	15,343	**3,659**	2,174	3,968	4,838	4,736	5,603	5,004	4,545	5,857
Operating Margin [3]	**296**	3,596	**594**	291	(589)	864	1,080	1,277	1,239	135	1,191
Cash From (Used in) Operating Activities	**23**	2,545	**732**	(834)	125	740	834	1,275	436	488	1,258
Adjusted Funds Flow [4]	**(194)**	3,015	**414**	(462)	(146)	687	928	1,082	1,005	7	980
Operating Earnings (Loss)	**(2,053)**	620	**(452)**	(414)	(1,187)	(164)	284	267	69	(1,670)	(41)
Per Share [5] ($)	**(1.67)**	0.50	**(0.37)**	(0.34)	(0.97)	(0.13)	0.23	0.22	0.06	(1.36)	(0.03)
Net Earnings (Loss)	**(2,226)**	2,081	**(194)**	(235)	(1,797)	113	187	1,784	110	(1,350)	(242)
Per Share [5] ($)	**(1.81)**	1.69	**(0.16)**	(0.19)	(1.46)	0.09	0.15	1.45	0.09	(1.10)	(0.20)
Capital Investment [6]	**599**	859	**148**	147	304	317	294	248	317	276	271
Dividends											
Cash Dividends	**77**	183	**-**	-	77	77	60	62	61	62	61
Per Share ($)	**0.0625**	0.1500	**-**	-	0.0625	0.0625	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 and reversals.
(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

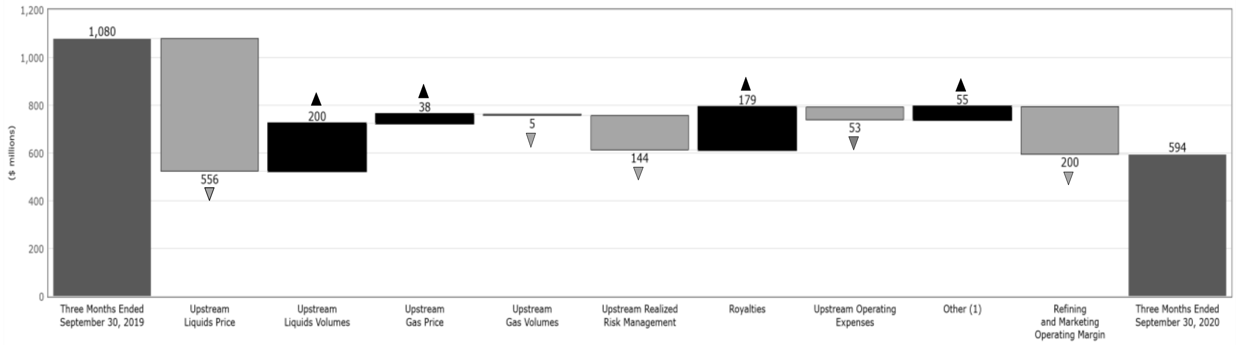
($ millions)	Three Months Ended September 30, 2020	Three Months Ended September 30, 2019 [1]	Nine Months Ended September 30, 2020	Nine Months Ended September 30, 2019 [1]
Gross Sales	**3,920**	5,273	**10,444**	16,638
Less: Royalties	**153**	332	**221**	847
Revenues	**3,767**	4,941	**10,223**	15,791
Expenses				
Purchased Product	**1,444**	2,026	**4,170**	6,622
Transportation and Blending	**1,036**	1,269	**3,331**	3,798
Operating Expenses	**554**	559	**1,655**	1,726
Production and Mineral Taxes	**-**	1	**-**	1
Inventory Write-Down (Reversal)	**-**	16	**549**	24
Realized (Gain) Loss on Risk Management Activities	**139**	(10)	**222**	24
Operating Margin	**594**	1,080	**296**	3,596

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

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, production and mineral taxes, inventory write-downs, net of reversals, 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 September 30, 2020 Compared With September 30, 2019

Operating Margin Variance



(1) Other includes the net effect of 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 three months ended September 30, 2020 compared with 2019 primarily due to:

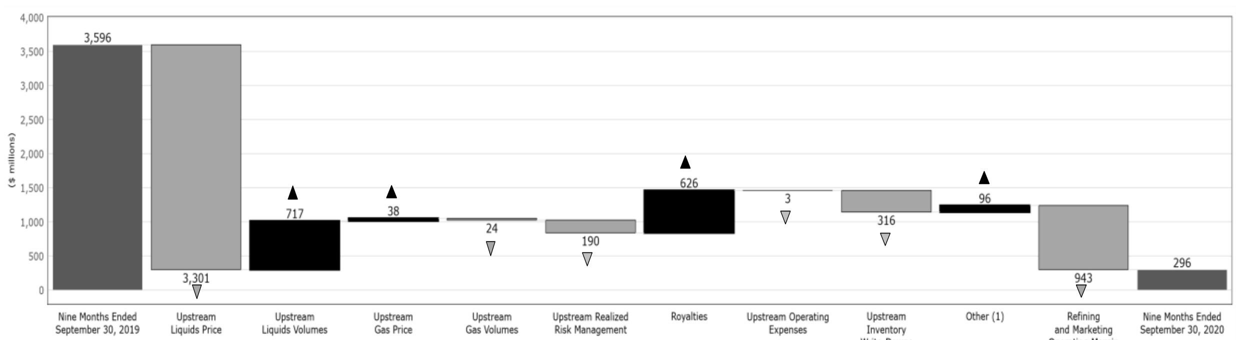
- A decrease in our average crude oil sales price resulting from lower WTI benchmark pricing;
- Lower Operating Margin from our Refining and Marketing segment due to reduced market crack spreads, reduced crude oil runs and lower crude advantage, partially offset by lower operating costs; and
- Upstream realized risk management losses of $137 million (2019 – gains of $7 million).

These decreases in Operating Margin were partially offset by:

- Higher liquids sales volumes as we sold inventory built up in low pricing months and increased production in response to higher prices;
- Lower royalties due to lower realized prices; and
- A decrease in transportation and blending expenses due to lower condensate price used for blending and lower rail costs, partially offset by higher condensate volumes.

Nine Months Ended September 30, 2020 Compared With September 30, 2019

Operating Margin Variance



(1) Other includes the net effect of 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 2020 compared with 2019 primarily due to:

- A lower average crude oil sales price resulting from lower WTI benchmark pricing and wider WTI-WCS differentials;
- Lower Operating Margin from our Refining and Marketing segment primarily due to $233 million in inventory write-downs, net of reversals, as a result of declines in refined product and crude oil prices. Operating Margin was also impacted by reduced market crack spreads, lower crude advantage and reduced crude oil runs. The

decline in Refining and Marketing operating margin was partially offset by higher margins on refined products and lower operating costs;
- Product inventory write-downs, net of reversals, of $316 million related to our upstream assets; and
- Upstream realized risk management losses of $228 million (2019 – losses of $38 million).

These decreases in Operating Margin were partially offset by:

- Higher liquids sales volumes;
- Lower royalties due to lower realized prices; and
- A decrease in transportation and blending expenses due to lower priced condensate used for blending.

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

Cash From (Used in) 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 (used in) 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 and reversals), 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.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
($ millions)	**2020**	2019	**2020**	2019
Cash From (Used in) Operating Activities	**732**	834	**23**	2,545
(Add) Deduct:				
Net Change in Other Assets and Liabilities	**(10)**	(21)	**(58)**	(55)
Net Change in Non-Cash Working Capital (1)	**328**	(73)	**275**	(415)
Adjusted Funds Flow (1)	**414**	928	**(194)**	3,015

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

Cash From Operating Activities and Adjusted Funds Flow decreased for the three months ended September 30, 2020 compared with 2019, primarily due to lower Operating Margin, as discussed above, partially offset by lower current taxes. The change in non-cash working capital as presented in the interim Consolidated Statements of Cash Flows for the third quarter of 2020 was primarily due to a decrease in accounts receivable and an increase in accounts payable, partially offset by an increase in inventory. For the three months ended September 30, 2019, the change in non-cash working capital was due to higher inventories and a decrease in accounts payable, partially offset by a decrease in accounts receivable and income tax receivable.

Cash From Operating Activities and Adjusted Funds Flow decreased for the nine months ended September 30, 2020 compared with 2019, primarily due to lower Operating Margin, as discussed above, partially offset by higher other income due to funding from the CEWS program, and lower current taxes. The change in non-cash working capital for the nine months ended September 30, 2020 was primarily due to a decrease in inventory and accounts receivable, partially offset by a decrease in accounts payable and income taxes payable. In 2019, the change in non-cash working capital was primarily due to an increase in inventory and accounts receivable, partially offset by a decrease in income tax receivable and 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 income 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 September 30, 2020	2019	Nine Months Ended September 30, 2020	2019
Earnings (Loss), Before Income Tax	**(372)**	239	**(2,884)**	1,314
Add (Deduct):				
Unrealized Risk Management (Gain) Loss [(1)]	**(135)**	9	**7**	157
Non-Operating Unrealized Foreign Exchange (Gain) Loss [(2)]	**(152)**	87	**164**	(529)
(Gain) Loss on Divestiture of Assets	**(1)**	3	**-**	7
Operating Earnings (Loss), Before Income Tax	**(660)**	338	**(2,713)**	949
Income Tax Expense (Recovery)	**(208)**	54	**(660)**	329
Total Operating Earnings (Loss)	**(452)**	284	**(2,053)**	620

(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 third quarter of 2020, we had an Operating Loss compared with Operating Earnings in 2019 primarily due to lower Cash From Operating Activities and Adjusted Funds Flow, as discussed above, and higher depreciation, depletion, and amortization ("DD&A") that included an impairment charge of $450 million for the Borger CGU, partially offset by non-operating realized foreign exchange gains of $30 million.

We had an Operating Loss for the nine months ended September 30, 2020, relative to Operating Earnings in 2019 primarily due to lower Cash Used in Operating Activities and Adjusted Funds Flow, as discussed above, higher DD&A that included impairment charges of $814 million, and operating unrealized foreign exchange losses of $65 million compared with gains of $18 million in 2019. The increase in our Operating Loss was partially offset by non-operating realized foreign exchange gains of $33 million compared with realized losses of $279 million in 2019 on our unsecured notes, a re-measurement gain of $97 million on the contingent payment compared with a loss of $137 million in 2019, and lower non-cash employee long-term incentive costs.

Net Earnings (Loss)

($ millions)	Three Months Ended	Nine Months Ended
Net Earnings (Loss), for the Periods Ended September 30, 2019	**187**	**2,081**
Increase (Decrease) due to:		
Operating Margin	**(486)**	**(3,300)**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**144**	**150**
Unrealized Foreign Exchange Gain (Loss)	**228**	**(789)**
Re-measurement of Contingent Payment	**14**	**234**
Gain (Loss) on Divestiture of Assets	**4**	**7**
Expenses [(1)]	**43**	**469**
DD&A	**(534)**	**(947)**
Exploration Expense	**(24)**	**(22)**
Income Tax Recovery (Expense)	**230**	**(109)**
Net Earnings (Loss), for the Periods Ended September 30, 2020	**(194)**	**(2,226)**

(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, research costs, other (income) loss, net, Corporate and Eliminations revenues, purchased product, transportation and blending, and operating expenses.

Our Net Loss of $194 million in the third quarter of 2020 was lower than Net Earnings of $187 million in the third quarter of 2019 primarily due to lower Operating Earnings, as discussed above. The decrease to Net Earnings was partially offset by:

- Non-operating unrealized foreign exchange gains of $152 million compared with losses of $87 million;
- Unrealized risk management gains of $135 million compared with losses of $9 million; and
- A deferred income tax recovery of $177 million compared with a deferred income tax expense of $46 million.

On a year-to-date basis, Net Loss of $2,226 million was significantly lower than Net Earnings of $2,081 million in 2019 due to:

- Lower Operating Earnings, as discussed above;
- Non-operating unrealized foreign exchange losses of $164 million compared with gains of $529 million in 2019; and
- A deferred income tax recovery of $656 million compared with a recovery of $790 million in 2019. In 2019, we recorded a deferred income tax recovery of $663 million associated with the reduction in the Alberta corporate tax rate and a recovery of $387 million due to a step-up in the tax basis of our refining assets.

The increase in Net Loss was partially offset by lower unrealized risk management losses of $7 million in 2020 compared with $157 million in 2019.

Capital Investment

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2020**	2019 (1)	**2020**	2019 (1)
Oil Sands	**65**	134	**337**	477
Conventional (2)	**12**	32	**39**	61
Refining and Marketing	**65**	87	**172**	214
Corporate and Eliminations	**6**	41	**51**	107
Capital Investment (3)	**148**	294	**599**	859

(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.

Capital investment in 2020 decreased compared with 2019, reflecting our reduced capital investment program and revised budget announced in April.

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)]

	Nine Months Ended September 30,					
(US$/bbl, unless otherwise indicated)	**2020**	**Percent Change**	2019	**Q3 2020**	Q2 2020	Q3 2019
Brent						
Average	**42.53**	**(34)**	64.74	**43.37**	33.27	62.00
WTI						
Average	**38.32**	**(33)**	57.06	**40.93**	27.85	56.45
Average Differential Brent-WTI	**4.21**	**(45)**	7.68	**2.44**	5.42	5.55
WCS at Hardisty ("WCS")						
Average	**24.63**	**(46)**	45.32	**31.84**	16.38	44.21
Average Differential WTI-WCS	**13.69**	**17**	11.74	**9.09**	11.47	12.24
Average (C$/bbl)	**32.98**	**(45)**	60.26	**42.41**	22.42	58.38
WCS at Nederland						
Average	**34.36**	**(40)**	56.93	**38.73**	22.55	52.76
Average Differential WTI-WCS at Nederland	**3.96**	**2,946**	0.13	**2.20**	5.30	3.69
West Texas Sour ("WTS")						
Average	**38.15**	**(32)**	55.93	**40.96**	28.03	55.88
Average Differential WTI-WTS	**0.17**	**(85)**	1.13	**(0.03)**	(0.18)	0.57
Condensate (C5 @ Edmonton)						
Average	**35.38**	**(33)**	52.81	**37.55**	22.30	52.02
Average Differential WTI-Condensate (Premium)/Discount	**2.94**	**(31)**	4.25	**3.38**	5.55	4.43
Average Differential WCS-Condensate (Premium)/Discount	**(10.75)**	**44**	(7.49)	**(5.71)**	(5.92)	(7.81)
Average (C$/bbl)	**47.47**	**(32)**	70.21	**49.99**	30.70	68.69
Average Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**44.55**	**(39)**	72.45	**48.75**	32.91	72.07
Chicago Ultra-low Sulphur Diesel ("ULSD")	**48.71**	**(37)**	77.92	**48.91**	36.89	75.34
Refining Margin: Average 3-2-1 Crack Spreads [(2)]						
Chicago	**7.71**	**(55)**	17.24	**7.89**	6.44	16.72
Group 3	**9.04**	**(48)**	17.36	**8.29**	7.92	17.32
Average Natural Gas Prices						
AECO [(3)] (C$/Mcf)	**2.07**	**49**	1.39	**2.15**	1.91	1.04
NYMEX (US$/Mcf)	**1.88**	**(30)**	2.67	**1.98**	1.72	2.23
Foreign Exchange Rate (US$ per C$1)						
Average	**0.739**	**(2)**	0.752	**0.751**	0.722	0.757
End of Period	**0.750**	**(1)**	0.755	**0.750**	0.734	0.755

(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 section 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 and Condensate Benchmarks

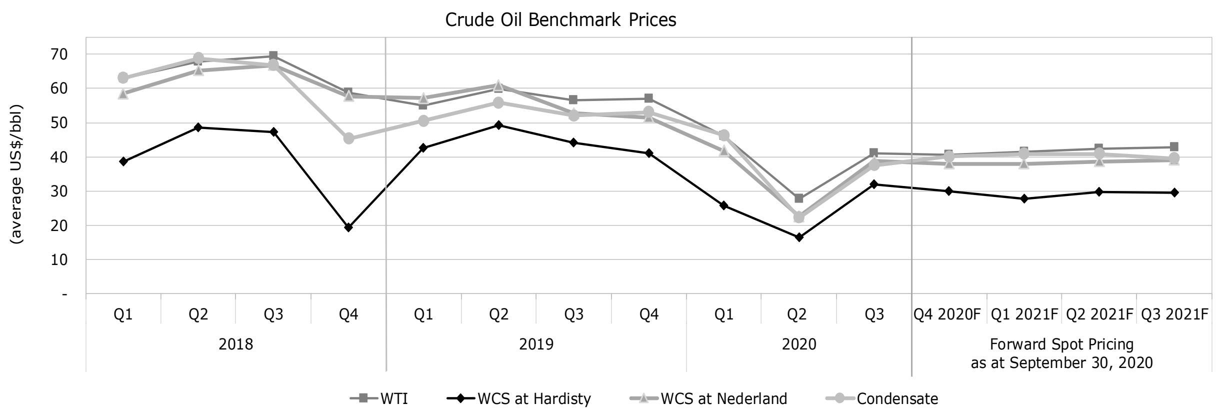
Through the quarter, crude oil benchmarks improved relative to the second quarter with the average Brent and WTI crude oil benchmark prices rising 30 percent and 47 percent, respectively. While global demand for crude oil in the third quarter improved from the second quarter lows and significant production shut-ins globally helped in stabilizing the market, demand for crude oil was still under pressure due to the resurgence of COVID-19 cases.

Year-over-year, the impacts of the global demand reduction have resulted in the average Brent and WTI crude oil benchmark prices being lower.

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 third quarter of 2020, the Brent-WTI differential narrowed compared with 2019 due to lower exports of crude oil from North America and reduced U.S. crude oil supply.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. In the second quarter of 2020, Alberta production cuts due to demand concerns from COVID-19 resulted in reduced Western Canadian Select Basin ("WCSB") supply causing heavy oil differentials to significantly narrow. As a result, the WCSB crude supply was able to clear volumes from Alberta by way of pipeline versus more expensive rail. In the third quarter of 2020, the WTI-WCS at Hardisty differential narrowed further from the second quarter as marginal transportation costs remained low and heavy crude benchmarks in the U.S. Gulf Coast ("USGC") also strengthened relative to WTI due to decreased global supply.

WCS at Nederland is a heavy oil benchmark at the USGC which is representative of pricing for our sales in the USGC. WCS at Nederland crude oil benchmark prices weakened in 2020 compared with 2019, consistent with falling crude oil prices globally as refiners lowered crude runs to adjust to reduced demand for products. In the third quarter of 2020, WCS at Nederland benchmark prices relative to WTI strengthened compared with the second quarter of 2020, benefitting from the lower supply of heavy and medium sour grades from Canadian and OPEC+ producers.



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 average differential between WTI and WTS benchmark prices narrowed in 2020 compared with 2019 as debottlenecking of transportation constraints resulted in WTS trading in a narrow range around parity with WTI pricing since early 2019.

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 in blending as well as timing of sales of blended product.

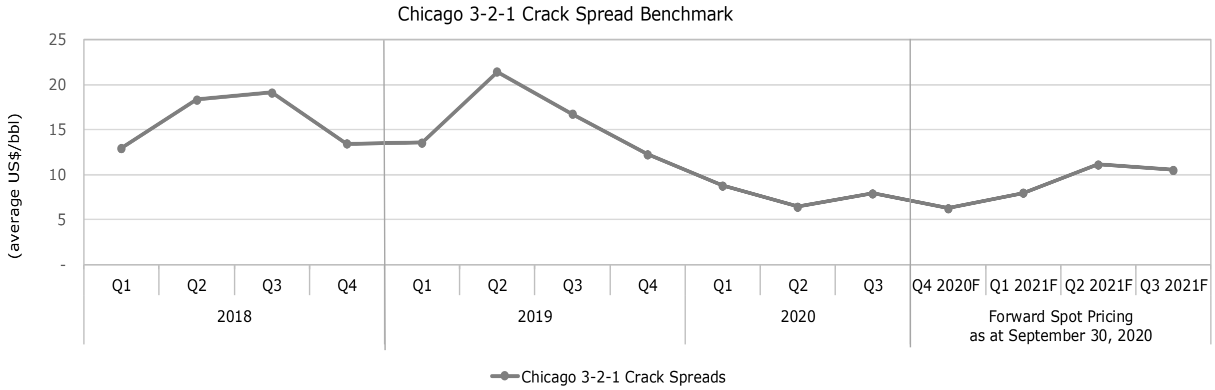
Average condensate benchmark prices were at a narrower discount relative to WTI in Alberta in the third quarter of 2020 compared with 2019. The benefit of weaker diluent demand in 2020 due to shut-in heavy oil production has been offset by lower imported barrels from the U.S. On a year-to-date basis, average condensate differentials to WTI narrowed compared with 2019.

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 third quarter and on a year-to-date basis compared with the same periods in 2019, primarily due to lower refined product demand as a result of COVID-19. Weaker refined product demand resulted in higher inventory levels which put pressure on market crack spreads. As North American refining crack spreads are expressed on a WTI basis, while refined products are set by global prices, the weakening 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 three and nine months ended September 30, 2020 compared with 2019 as the differential between AECO and NYMEX narrowed significantly due to lower than expected supply, ample access to domestic storage injections and lower pipeline utilization in the WCSB. Average NYMEX prices decreased compared with 2019 due to lower demand and a large decrease in liquid natural gas exports.

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.

The Canadian dollar on average weakened relative to the U.S. dollar in 2020, compared with 2019, resulting in a positive impact of approximately $170 million on our revenues in the nine months ended September 30, 2020. The weakening of the Canadian dollar relative to the U.S. dollar as at September 30, 2020 compared with December 31, 2019, resulted in unrealized foreign exchange losses of $164 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

($ millions)	Three Months Ended September 30, 2020	Percent Change	2019	Nine Months Ended September 30, 2020	Percent Change	2019
Oil Sands	**2,066**	**(13)**	2,386	**5,094**	**(31)**	7,352
Conventional [(1)]	**132**	**(2)**	135	**423**	**(12)**	481
Refining and Marketing	**1,569**	**(35)**	2,420	**4,706**	**(41)**	7,958
Corporate and Eliminations	**(108)**	**47**	(205)	**(422)**	**6**	(448)
	3,659	**(23)**	4,736	**9,801**	**(36)**	15,343

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

Oil Sands revenues decreased in the three and nine months ended September 30, 2020 compared with 2019 due to lower average realized liquids sales price, partially offset by higher sales volumes and lower royalties.

Conventional revenues declined slightly in the three months ended September 30, 2020 compared with the same period of 2019 due to higher royalties, primarily due to a 2019 Gas Cost Allowance ("GCA") true up, partially offset by a higher average natural gas sales price and production from our Marten Hills asset. On a year-to-date basis, Conventional revenues decreased compared with 2019 due to lower average realized liquids sales prices, lower natural gas sales volumes and higher royalties, partially offset by a higher average natural gas sales price and the commencement of production from our Marten Hills asset.

Refining and Marketing revenues declined 35 percent in the third quarter and 41 percent on a year-to-date basis compared with 2019. Refining revenues decreased due to lower refined product pricing consistent with the decline in average refined product benchmark prices and lower refined product output due to the economic crude rate reductions. Revenues from third-party crude oil and natural gas sales undertaken by our marketing group was relatively flat for the three months ended September 30, 2020 compared with the same period in 2019 due to lower crude oil prices and lower natural gas volumes, offset by higher crude oil volumes and natural gas prices. On a year-to-date basis, marketing revenues decreased compared with 2019 due to lower crude oil prices and lower volumes, partially offset by higher natural gas prices.

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

OIL SANDS

In the third quarter of 2020, we:

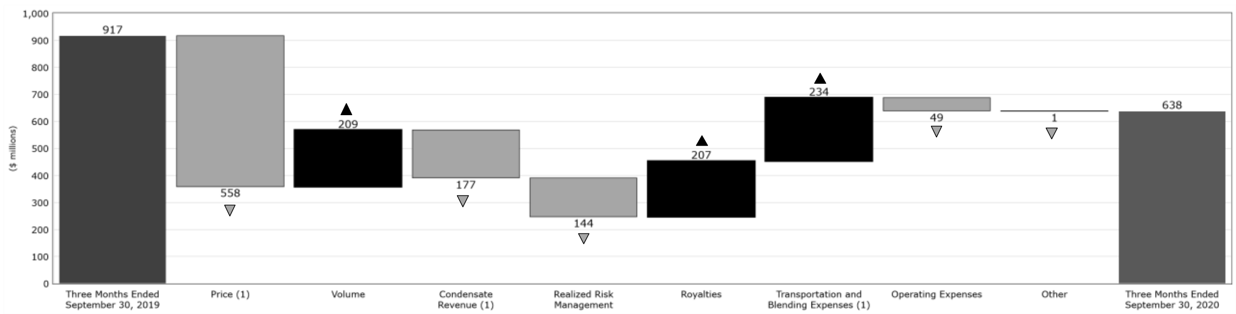
- Delivered safe and reliable operations;
- Increased our Oil Sands production rates to 385,937 barrels per day to produce above our curtailment limit by purchasing production curtailment credits to respond to higher crude oil benchmark prices, while managing to reduce the non-fuel per-unit operating costs. Overall, per-unit operating costs increased nine percent to $7.53 per barrel compared with $6.90 per barrel in the third quarter of 2019 due to higher natural gas prices;
- Demonstrated our ability to use our full suite of assets to maximize prices received for every barrel as we managed to store volumes in a low-price environment and cleared inventory when we could obtain higher prices; and
- Generated Operating Margin of $638 million, a decrease of $279 million compared with the third quarter of 2019 due to lower average realized sales prices, realized risk management losses compared with gains in 2019, partially offset by lower transportation and blending costs, higher volumes and lower royalties.

Three Months Ended September 30, 2020 Compared With September 30, 2019

Financial Results

($ millions)	Three Months Ended September 30, 2020	2019
Gross Sales	**2,195**	2,722
Less: Royalties	**129**	336
Revenues	**2,066**	2,386
Expenses		
Transportation and Blending	**1,015**	1,249
Operating	**276**	227
(Gain) Loss on Risk Management	**137**	(7)
Operating Margin	**638**	917
Depreciation, Depletion and Amortization	**469**	391
Exploration Expense	**-**	1
Segment Income (Loss)	**169**	525

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

Our realized crude oil sales price was $39.67 per barrel in the third quarter (2019 – $54.94 per barrel), consistent with the overall decline in crude oil benchmark pricing led by a 28 percent decline in WTI average benchmark price, partially offset by the narrowing of the WTI-WCS differential to an average discount of US$9.09 per barrel (2019 – discount of US$12.24 per barrel), narrower WCS-Christina Dilbit Blend ("CDB") differential and lower priced condensate used for blending. The WCS-CDB differential narrowed to a historically low discount of US$1.07 per barrel (2019 – discount of US$2.00 per barrel) mainly due to increased demand for the CDB crude type. In the three months ended September 30, 2020, we sold approximately 20 percent (2019 – approximately one third) of our production at sales locations outside of Alberta, to improve our realized sales price.

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 decreases relative to the price of blended crude oil, our realized bitumen sales price increases. 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. During the quarter we reduced condensate volumes transported from the USGC, shipping when the price differential between market hubs is significant enough to cover variable transportation costs.

Production Volumes

(barrels per day)	Three Months Ended September 30, 2020	Percent Change	2019
Foster Creek	**164,954**	**5**	156,527
Christina Lake	**220,983**	**12**	198,068
	385,937	**9**	354,595

Production at Foster Creek increased year-over-year with the facility targeting maximum production rates, other than during planned maintenance. During the quarter, we were able to purchase additional production curtailment credits allowing us to operate Christina Lake at increased production levels as commodity prices improved. Planned turnaround and maintenance commenced at Christina Lake in late September reducing production. In the three months ended September 30, 2019, production volumes were reduced due to the government curtailment program restrictions.

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). For royalty purposes, gross revenues are a function of sales revenues less diluent costs and transportation costs and 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

(percent)	Three Months Ended September 30, 2020	2019
Foster Creek	**7.4**	21.8
Christina Lake	**13.4**	24.2

In the third quarter of 2020, royalties decreased $207 million compared with 2019, as a result of lower net profits due to lower commodity pricing, combined with lower Alberta Department of Energy posted royalty rates resulting from decreased annual average WTI benchmark pricing.

Expenses

Transportation and Blending

Transportation and blending costs decreased $234 million compared with the third quarter of 2019. Blending costs decreased due to lower priced condensate, partially offset by higher condensate volumes as a result of increased sales 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.

Transportation costs were lower due to the temporary suspension of our crude-by-rail program as we now only incur fixed costs associated with the program. The lower transportation costs were partially offset by higher fixed costs as our freight and offloading commitments escalated after the third quarter of 2019. In addition, we entered into a new tankage and offloading commitment at the end of September 2019. In the third quarter of 2020, we transported approximately 20 percent of our volumes to U.S. destinations by pipeline, compared with approximately one third in 2019, by pipeline and rail. Our crude-by-rail program continues to be temporarily suspended and we anticipate transportation costs will continue to be lower while the temporary suspension is in place.

Per-unit Transportation Expenses

Foster Creek per-unit transportation costs decreased $4.59 per barrel to $8.59 per barrel due to lower rail sales, partially offset by higher fixed rail transportation costs, as discussed above. Christina Lake per-unit transportation costs decreased $0.42 per barrel to $6.78 per barrel as a result of increased total sales volumes and lower rail sales, partially offset by higher pipeline tariff rates and higher fixed rail transportation costs, as discussed above.

Operating

Operating expenses in the third quarter focused on maintaining safe and reliable operations. Total and per-unit operating costs increased year over year primarily due to higher fuel costs from increased natural gas prices. Non-fuel costs increased mainly due to increased electricity prices and workover costs due to increased production. Non-fuel per-unit operating costs at Foster Creek were relatively flat, while at Christina Lake higher sales volumes reduced non-fuel per-unit operating costs.

Per-unit Operating Expenses

	Three Months Ended September 30,		
($/bbl)	**2020**	**Percent Change**	2019
Foster Creek			
Fuel	**2.60**	**59**	1.64
Non-fuel	**6.44**	**1**	6.36
Total	**9.04**	**13**	8.00
Christina Lake			
Fuel	**2.03**	**68**	1.21
Non-fuel	**4.50**	**(5)**	4.75
Total	**6.53**	**10**	5.96
Total	**7.53**	**9**	6.90

Netbacks (1)

Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis. 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 non-cash write-downs or reversals of product inventory until it is realized when 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.

	Foster Creek		Christina Lake	
	Three Months Ended September 30,			
($/bbl)	**2020 (2)**	2019	**2020 (2)**	2019
Sales Price	**41.51**	58.89	**38.44**	51.62
Royalties	**2.44**	9.90	**4.27**	10.62
Transportation and Blending	**8.59**	13.18	**6.78**	7.20
Operating Expenses	**9.04**	8.00	**6.53**	5.96
Netback Excluding Realized Risk Management	**21.44**	27.81	**20.86**	27.84
Realized Risk Management Gain (Loss)	**(3.67)**	0.13	**(3.77)**	0.27
Netback Including Realized Risk Management	**17.77**	27.94	**17.09**	28.11

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

Our average Netback, excluding realized risk management gains and losses, decreased in the third quarter compared with 2019, primarily due to lower realized sales prices, higher per-unit operating costs, partially offset by lower per-unit royalties and transportation and blending costs, and higher sales volumes at Christina Lake. For the three months ended September 30, 2020, the weakening of the Canadian dollar relative to the U.S. dollar compared with the same period of 2019 had a positive impact on our reported sales price of approximately $0.33 per barrel.

Risk Management

Risk Management – Cash Flow

Risk management positions in the third quarter of 2020 resulted in realized losses of $11 million (2019 – realized losses of $nil) due to settled commodity prices compared with our contract prices on risk management contracts. These risk management positions are placed to protect both near-term and future cash flows.

Risk Management – Optimization

Risk management positions in the third quarter of 2020 resulted in realized losses of $126 million (2019 – realized gains of $7 million) due to our decisions to store rather than sell our physical crude oil and condensate volumes, as discussed below. Cenovus uses its marketing and transportation initiatives, including storage and pipeline assets to optimize product mix, delivery points, transportation commitments and customer diversification, to inventory physical positions. At the time we make decisions to store crude oil and condensate volumes, the prices available for the future periods we plan to sell in can be locked in and the improved margin realized in the future periods, which are superior to short-term prices. The fluctuations in revenues generated from the underlying physical sales will be mitigated by the related risk management gains and losses.

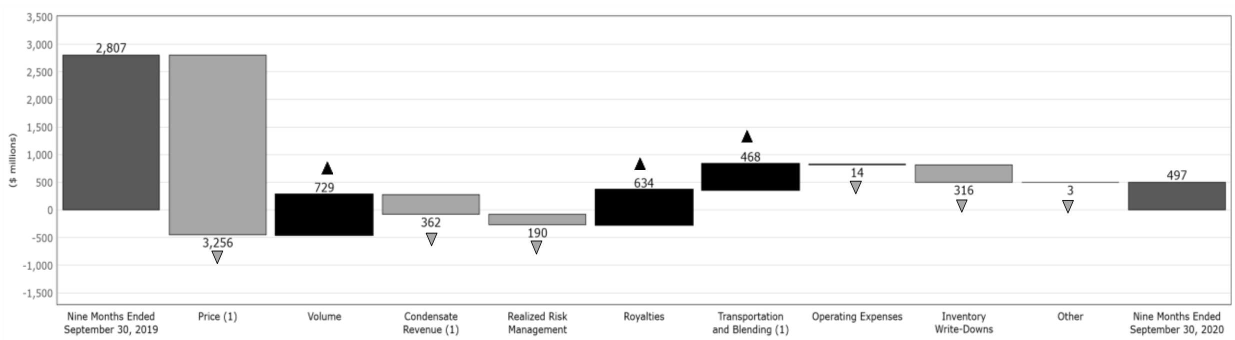
Transactions typically span across periods in order to execute the optimization strategy and these transactions reside across both realized and unrealized risk management. As the financial contracts settle, they will flow from unrealized to realized risk management gains and losses and final settlement will match when the physical product is sold.

Nine Months Ended September 30, 2020 Compared With September 30, 2019

Financial Results

($ millions)	Nine Months Ended September 30, 2020	2019
Gross Sales	**5,287**	8,179
Less: Royalties	**193**	827
Revenues	**5,094**	7,352
Expenses		
Transportation and Blending	**3,268**	3,736
Operating	**785**	771
Inventory Write-Down (Reversal)	**316**	-
(Gain) Loss on Risk Management	**228**	38
Operating Margin	**497**	2,807
Depreciation, Depletion and Amortization	**1,275**	1,127
Exploration Expense	**7**	10
Segment Income (Loss)	**(785)**	1,670

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 nine months ended September 30, 2020, our realized crude oil sales price was $25.21 per barrel compared with $55.82 per barrel in 2019, consistent with the overall declines in crude oil benchmark pricing led by a decrease in WTI average benchmark price, the widening of the WTI-WCS differential to an average of US$13.69 per barrel (2019 – US$11.74 per barrel), partially offset by the lower average price of condensate of US$35.38 per barrel (2019 – US$52.81 per barrel). The decrease in our crude oil price also reflects the wider WCS-Condensate premium of US$10.75 per barrel (2019 – premium of US$7.49 per barrel). In the nine months ended September 30, 2020, we sold approximately one quarter of our production volumes at sales locations outside of Alberta as our storage capabilities outside of Alberta increased allowing us to respond to price signals. In 2019, we sold approximately one quarter of our production at sales locations outside of Alberta due to volumes shipped by rail.

Production Volumes

(barrels per day)	Nine Months Ended September 30, 2020	Percent Change	2019
Foster Creek	**164,935**	**4**	158,888
Christina Lake	**217,133**	**15**	188,671
	382,068	**10**	347,559

Overall, production levels in the nine months ended September 30, 2020 were higher than 2019, when our production was in line with the Government of Alberta's mandatory production curtailment program. In 2020, we actively managed production levels to respond to price signals and the availability of production curtailment credits, both our own and those available in the market. In addition, the production increases were partially offset by our planned turnaround and maintenance at Christina Lake in the third quarter which had less of an impact than the Christina Lake planned turnaround in the second quarter of 2019.

Royalties

Effective Royalty Rates

(percent)	Nine Months Ended September 30, 2020	2019
Foster Creek	**9.2**	17.4
Christina Lake	**13.0**	20.6

On a year-to-date basis, royalties decreased $634 million compared with 2019 as a result of lower net profits due to lower commodity pricing, combined with lower Alberta Department of Energy posted royalty rates from decreased annual average WTI benchmark pricing.

Expenses

Transportation and Blending

Year over year, transportation and blending costs have decreased $468 million. Blending costs decreased due to a decline in condensate price, partially offset by increased condensate volumes required to move increased bitumen 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 higher fixed costs in 2020, as our rail freight and offloading commitments escalated after the third quarter of 2019. In addition, we entered into a new tankage and offloading commitment at the end of September 2019. On a year-to-date basis, before the suspension of our rail program, we shipped by rail 33,780 barrels per day to locations outside of Alberta (2019 – 38,765 barrels per day). Transporting our volumes to U.S. destinations, either by pipeline or rail, allows us to achieve better market prices.

Per-unit Transportation Expenses

Foster Creek per-barrel transportation costs increased $0.72 per barrel due to increased rail transportation costs from higher fixed costs in 2020, as discussed above, partially offset by lower pipeline tariffs as a result of lower sales to U.S. destinations and increased sales volumes. Christina Lake transportation costs increased $0.93 per barrel as a result of higher fixed costs, as discussed above, increased pipeline tariff rates, and higher storage costs, partially offset by increased sales volumes relative to 2019.

Operating

Primary drivers of our operating expenses in 2020 were fuel, workforce, chemical costs, and repairs and maintenance. Total operating costs increased $14 million due to higher fuel, workforce, and chemical costs due to increased production, partially offset by lower repairs and maintenance costs and fluid, waste handling and trucking costs due to the planned turnaround at Christina Lake in the second quarter of 2019.

Per-unit Operating Expenses

($/bbl)	2020	Percent Change	2019
	Nine Months Ended September 30,		
Foster Creek			
Fuel	**2.60**	**13**	2.30
Non-fuel	**6.28**	**(7)**	6.78
Total	**8.88**	**(2)**	9.08
Christina Lake			
Fuel	**2.03**	**7**	1.90
Non-fuel	**4.53**	**(18)**	5.50
Total	**6.56**	**(11)**	7.40
Total	**7.55**	**(8)**	8.18

At both Foster Creek and Christina Lake, per-barrel fuel costs increased due to higher natural gas prices, partially offset by higher sales volumes.

Per-barrel non-fuel operating expenses at Foster Creek decreased in 2020 primarily due to higher sales volumes and COVID-19 safety measures implemented in the second quarter resulting in less repairs and maintenance activity, partially offset by higher workforce costs.

Per-barrel non-fuel operating expenses at Christina Lake decreased in 2020 primarily due to higher sales volumes, and lower costs due to the planned turnaround in 2019, partially offset by higher workforce and chemical costs.

Inventory Write-Down (Reversal)

In the first quarter of 2020, we recorded $335 million in inventory write-downs of our crude oil blend and condensate, and subsequently reversed $19 million due to improved crude oil prices.

Netbacks (1)

	Foster Creek		Christina Lake	
	Nine Months Ended September 30,			
($/bbl)	**2020 (2)**	2019	**2020 (2)**	2019
Sales Price	**27.31**	59.04	**23.64**	53.02
Royalties	**1.47**	8.19	**2.18**	9.44
Transportation and Blending	**11.48**	10.76	**7.09**	6.16
Operating Expenses	**8.88**	9.08	**6.56**	7.40
Netback Excluding Realized Risk Management	**5.48**	31.01	**7.81**	30.02
Realized Risk Management Gain (Loss)	**(2.10)**	(0.35)	**(2.17)**	(0.45)
Netback Including Realized Risk Management	**3.38**	30.66	**5.64**	29.57

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

Our average Netback, excluding realized risk management gains and losses, decreased in 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 overall reported sales price of approximately $0.43 per barrel.

Risk Management

Risk Management – Cash Flow

Risk management positions in 2020 resulted in realized losses of $15 million (2019 – realized losses of $16 million), due to settled commodity prices compared with our contract prices on risk management contracts. These risk management positions are placed to protect both near-term and future cash flows.

Risk Management – Optimization

Risk management positions in 2020 resulted in realized losses of $213 million (2019 – realized losses of $22 million) due to our decisions to store rather than sell our physical crude oil and condensate volumes. Cenovus uses its marketing and transportation initiatives, including storage and pipeline assets to optimize product mix, delivery points, transportation commitments and customer diversification, to inventory physical positions. At the time we make the decision to store crude oil and condensate volumes, the prices available for future periods we plan to sell in can be locked in and the improved margin realized in the future periods, which are superior to short-term prices. The fluctuations in revenues generated from the underlying physical sales will be mitigated by the related risk management gains and losses.

Transactions typically span across periods in order to execute the optimization strategy and these transactions reside across both realized and unrealized risk management. As the financial contracts settle, they will flow from unrealized to realized risk management gains and losses and final settlement will match when the physical product is sold.

DD&A

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 each 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 three months ended September 30, 2020, Oil Sands DD&A increased $78 million compared with 2019 due to $46 million of previously capitalized PP&E costs written off as additional DD&A and higher sales volumes, partially offset by a decrease in our average depletion rates. On a year-to-date basis, DD&A increased $148 million compared with the same period of 2020, 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 nine months ended September 30, 2020 was approximately $10.40 per barrel (2019 – $11.15 per barrel).

We depreciate our ROU assets on a straight-line basis over the shorter of the estimated useful life or the lease term.

Capital Investment

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2020**	2019	**2020**	2019
Foster Creek	**32**	46	**157**	169
Christina Lake	**27**	84	**117**	279
	59	130	**274**	448
Other (1)	**6**	4	**63**	29
Capital Investment (2)	**65**	134	**337**	477

(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.

In 2020, Oil Sands capital investment focused on sustaining 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 sustaining and stratigraphic test well programs and the completion of Christina Lake phase G construction.

Drilling Activity

	Gross Stratigraphic Test Wells		Gross Production Wells (1) (2)	
Nine Months Ended September 30,	**2020**	2019	**2020**	2019
Foster Creek	**38**	14	**-**	-
Christina Lake	**42**	18	**-**	11
	80	32	**-**	11
Other	**75**	14	**-**	-
	155	46	**-**	11

(1) Steam-assisted gravity drainage well pairs are counted as a single producing well.
(2) 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.

Stratigraphic test wells were drilled in the first quarter to help identify well pad locations for sustaining wells and future expansion phases, and to further progress the evaluation of emerging assets.

Future Capital Investment

Oil Sands capital investment for 2020 is forecast to be between $370 million and $420 million, focused on sustaining capital. At current commodity prices we do not expect to sanction any new projects including phase H expansions at both Christina Lake and Foster Creek.

In 2020, we plan to spend a minimal amount of capital as a result of the challenging commodity price environment.

In 2020, our Technology and other capital investment, forecast to be between $35 million and $40 million, relates to advancing only select strategic initiatives such as solvents, partial upgrading and plant redesign that are expected to provide both cost and environmental benefits. Guidance dated April 1, 2020 is available on our website at cenovus.com.

CONVENTIONAL

In the third quarter of 2020, we:

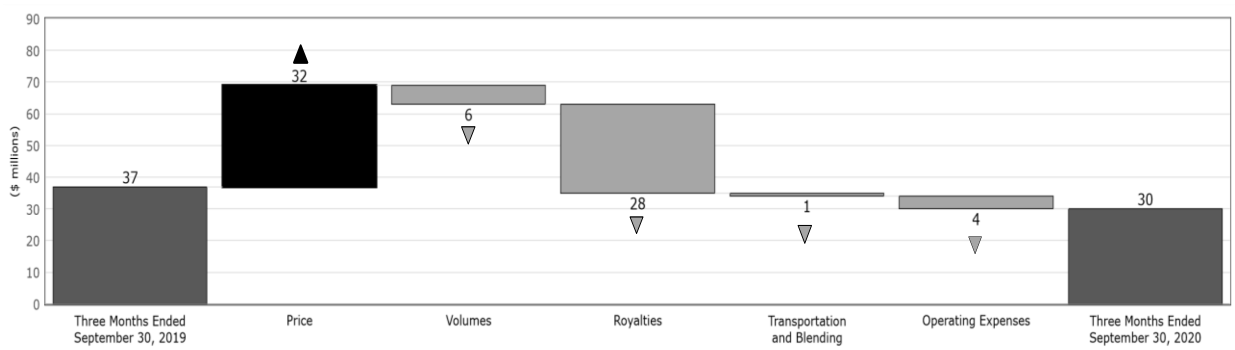
- Demonstrated good health and safety performance in light of the challenges presented by COVID-19;
- Produced a total of 85,862 BOE per day, a decrease compared with 2019 due to natural well declines and increased downtime due to a planned turnaround at a non-operated gas plant in the Elmworth-Wapiti area, partially offset by added production from the Marten Hills area. In the third quarter of 2019, production was impacted by temporary shut-ins from low natural gas prices;
- Generated Operating Margin of $30 million, a decrease from the same period of 2019 due to higher royalties from the 2019 annual true up of GCA, lower sales volumes and higher operating costs, partially offset by a higher realized natural gas sales price; and
- Earned a Netback of $3.16 per BOE, excluding realized risk management activities.

Financial Results

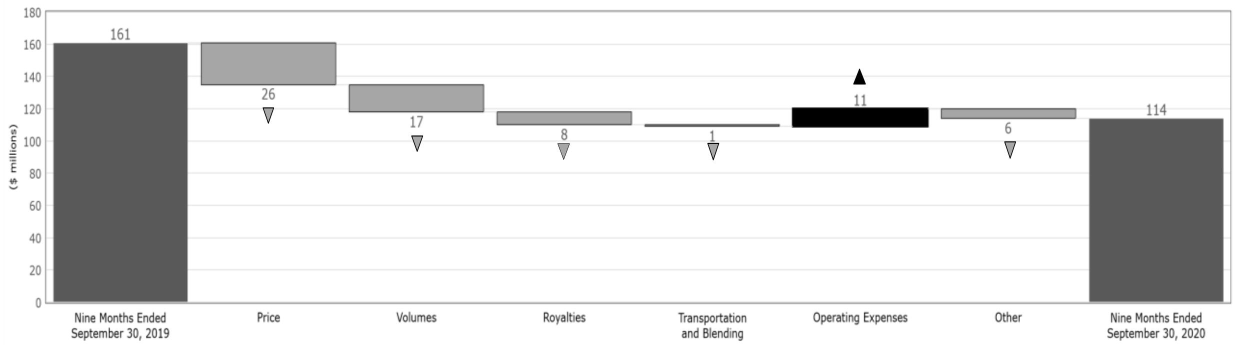
	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2020**	2019	**2020**	2019
Gross Sales	**156**	131	**451**	501
Less: Royalties	**24**	(4)	**28**	20
Revenues	**132**	135	**423**	481
Expenses				
Transportation and Blending	**21**	20	**63**	62
Operating	**81**	77	**246**	257
Production and Mineral Taxes	**-**	1	**-**	1
Operating Margin	**30**	37	**114**	161
Depreciation, Depletion and Amortization	**75**	78	**563**	247
Exploration Expense	**25**	-	**25**	-
Segment Income (Loss)	**(70)**	(41)	**(474)**	(86)

Operating Margin Variance

Three Months Ended September 30, 2020 Compared With September 30, 2019



Nine Months Ended September 30, 2020 Compared With September 30, 2019



Revenues

Price

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	**2020**	2019
Heavy Oil ($/bbl)	**39.54**	-	**29.80**	-
Light and Medium Oil ($/bbl)	**49.19**	68.53	**42.15**	66.08
NGLs ($/bbl)	**21.38**	22.16	**20.26**	26.08
Natural Gas ($/mcf)	**2.34**	1.21	**2.18**	1.82
Total Oil Equivalent ($/BOE)	**18.28**	13.84	**16.64**	17.03

Revenues declined slightly for the three months ended September 30, 2020 compared with 2019 as the higher natural gas prices were more than offset by higher royalties. For the nine months ended September 30, 2020, revenues declined compared with 2019 due to decreased average realized liquids sales prices and lower natural gas sales volumes, partially offset by higher liquids sales volumes. In 2020, we had heavy oil production from Marten Hills of approximately 3,000 barrels per day. For the three and nine months ended September 30, 2020, revenues included $11 million and $35 million, respectively, of processing fee revenue related to our interests in natural gas processing facilities (2019 – $12 million and $42 million, respectively). We do not include processing fee revenue in our per-unit pricing metrics or our Netbacks.

Production Volumes

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	**2020**	2019
Liquids				
Crude Oil (barrels per day)	**7,554**	4,929	**7,585**	4,885
NGLs (barrels per day)	**18,297**	21,175	**19,901**	21,950
	25,851	26,104	**27,486**	26,835
Natural Gas (MMcf per day)	**360**	407	**382**	432
Total Production (BOE/d)	**85,862**	93,901	**91,196**	98,807
Natural Gas Production (percentage of total)	**70**	72	**70**	73
Liquids Production (percentage of total)	**30**	28	**30**	27

Production for the three months ended September 30, 2020 declined nine percent, compared with 2019 due to natural declines from lower sustaining capital investment and increased downtime due to a planned turnaround at a non-operated gas plant in the Elmworth-Wapiti area, partially offset by Marten Hills heavy oil production starting in 2020. In the third quarter of 2019, production was impacted by temporary shut-ins from low natural gas prices. Production for the nine months ended September 30, 2020 decreased eight percent compared with 2019 due to natural well declines, partially offset by Marten Hills heavy oil production and fewer shut-ins for low commodity pricing.

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 share of raw gas at producer-owned gas plants as well as transport the Crown's share of residue gas, NGLs or oil through producer-owned plants.

For the three and nine months ended September 30, 2020, our effective royalty rate was 18.5 percent and 7.7 percent, respectively (2019 – negative 3.4 percent and 5.1 percent, respectively). The higher royalty rates are due to a 2019 GCA royalty true up of $8 million booked in 2020, as a result of a reduction in capital and operating expenses in 2019.

Expenses

Transportation

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. For the three months ended September 30, 2020 and on a year-to-date basis, per-unit transportation costs averaged $2.62 per BOE (2019 – $2.28 per BOE) and averaged $2.51 per BOE (2019 – $2.29 per BOE), respectively, due to lower sales volumes and increased pipeline costs.

Operating

Total operating costs in the three months ended September 30, 2020 increased to $81 million (2019 – $77 million) due to planned turnaround costs, higher third-party processing fees, and operating costs related to Marten Hills production. For the nine months ended September 30, 2020 total operating costs decreased to $246 million (2019 – $257 million) as a result of optimizing operations, focusing on critical repair and maintenance activities and leveraging our infrastructure to lower the cost structure.

Per-unit operating costs increased to average $9.55 per BOE (2019 – $8.21 per BOE) in the three months ended September 30, 2020 as a result of lower sales volumes and higher repairs and maintenance activity primarily due to planned turnaround costs and higher third-party processing fees. On a year-to-date basis, per-unit operating costs increased to an average of $9.19 per BOE (2019 – $8.83 per BOE) primarily due to lower sales volumes and higher third-party processing fees.

These increases were partially offset by:

- decreased property tax and lease costs primarily for lower lease rentals and from regulatory cost relief;
- lower workforce costs; and
- lower repairs and maintenance as a result of lower activity and deferrals.

Netbacks

	Three Months Ended September 30,		Nine Months Ended September 30,	
($/BOE)	**2020**	2019	**2020**	2019
Sales Price	**18.28**	13.84	**16.64**	17.03
Royalties	**2.93**	(0.41)	**1.09**	0.76
Transportation and Blending	**2.62**	2.28	**2.51**	2.29
Operating Expenses	**9.55**	8.21	**9.19**	8.83
Production and Mineral Taxes	**0.02**	0.03	**-**	0.03
Netback Excluding Realized Risk Management	**3.16**	3.73	**3.85**	5.12
Realized Risk Management Gain (Loss)	**(0.03)**	-	**(0.01)**	(0.01)
Netback Including Realized Risk Management	**3.13**	3.73	**3.84**	5.11

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 $9.60 per BOE and $10.00 per BOE for the three and nine months ended September 30, 2020, respectively (2019 – $8.90 per BOE and $9.10 per BOE, respectively).

For the three and nine months ended September 30, 2020, total Conventional DD&A was $75 million and $563 million, respectively (2019 – $78 million and $247 million, respectively). The DD&A was slightly lower compared with the third quarter of 2019 due to lower sales volumes offset by higher DD&A rates. On a year-to-date basis 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.

Exploration expense of $25 million was recorded in the three and nine months ended September 30, 2020 (2019 – $nil) related to previously capitalized E&E costs written off as we have relinquished the legal right to explore on certain leased acreage.

Capital Investment

In the three and nine months ended September 30, 2020, we invested $12 million and $39 million, respectively, compared with $32 million and $61 million for the same periods of 2019. Capital investment to date focused on the disciplined development of our Conventional assets, which encompassed maintaining safe and reliable operations, acquiring seismic data, start-up of a recompletion program to optimize existing production and commencement of activities to support drilling and infrastructure.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2020**	2019 (1)	**2020**	2019 (1)
Seismic	**-**	-	**5**	-
Drilling and Completions	**1**	11	**2**	13
Facilities	**5**	12	**15**	21
Other	**6**	9	**17**	27
Capital Investment (2)	**12**	32	**39**	61

(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 third quarter of 2020 there were no net wells drilled, completed, and tied-in. For the nine months ended September 30, 2020 there were no net wells drilled or completed and two wells were tied-in and brought on production. In the third quarter of 2019, there were two wells drilled and on a year-to-date basis, there were two wells drilled and one well tied-in.

Future Capital Investment

Our 2020 Conventional capital investment is forecasted to be between $75 million and $85 million. This includes an incremental $30 million in the fourth quarter, relative to Conventional (previously Deep Basin) guidance, for a two-rig drilling program targeting low-risk, high-return development wells near our owned and operated natural gas plants to take advantage of an expected strengthening in commodity prices during the winter heating season. We continue to take a disciplined approach to the development of our Conventional assets. 2020 Guidance dated April 1, 2020 is available on our website at cenovus.com.

REFINING AND MARKETING

In the third quarter of 2020, we:

- Managed to economic crude oil runs of 382,000 barrels per day, lower than the third quarter of 2019 in response to the economic slowdown due to COVID-19;
- Reported Operating Margin of negative $74 million, a decrease of $200 million compared with 2019, due to lower global crude oil and refined product pricing, which led to decreased market crack spreads and lower crude advantage, and decreased crude oil runs, partially offset by lower operating costs; and
- Recorded an impairment charge of $450 million, as additional DD&A expense, associated with the Borger CGU.

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2020**	2019 (1)	**2020**	2019 (1)
Revenues	**1,569**	2,420	**4,706**	7,958
Purchased Product	**1,444**	2,026	**4,170**	6,622
Inventory Write-Down (Reversal)	**-**	16	**233**	24
Gross Margin	**125**	378	**303**	1,312
Expenses				
Operating	**197**	255	**624**	698
(Gain) Loss on Risk Management	**2**	(3)	**(6)**	(14)
Operating Margin	**(74)**	126	**(315)**	628
Depreciation, Depletion and Amortization	**521**	65	**673**	213
Segment Income (Loss)	**(595)**	61	**(988)**	415

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

Refinery Operations [(1)]

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2020	2019	**2020**	2019
Crude Oil Capacity (Mbbls/d)	**495**	482	**495**	482
Crude Oil Runs (Mbbls/d)	**382**	465	**383**	438
Heavy Crude Oil	**154**	185	**154**	174
Light/Medium	**228**	280	**229**	264
Refined Products (Mbbls/d)	**397**	485	**396**	463
Gasoline	**207**	215	**195**	218
Distillate	**115**	169	**130**	162
Other	**75**	101	**71**	83
Crude Utilization (percent)	**77**	96	**77**	91

(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 WCS 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 decreased in the third quarter as both Refineries continued crude rate reductions in response to the reduced demand and weak pricing for refined products due to COVID-19. In the third quarter of 2019, there were unplanned outages and the startup of planned turnaround activities at both Refineries in September 2019, partially offset by Wood River achieving a record monthly crude oil run rate in July 2019. For the three and nine months ended September 30, 2020, crude oil runs and refined product output decreased compared with the prior year, as the economic crude rate reductions in 2020 had a greater impact than planned and unplanned maintenance in 2019.

Crude-By-Rail Terminal

As announced in the first quarter, our crude-by-rail program continues to be suspended in response to the current market environment. The suspension was completed during the second quarter. In the three months ended September 30, 2020, we loaded an average of 8,753 barrels per day (no barrels per day of our volumes) from our Bruderheim crude-by-rail terminal compared with an average of 64,773 barrels per day (45,154 barrels per day of our volumes) in the third quarter of 2019. On a year-to-date basis, we loaded an average of 33,244 barrels per day (23,720 barrels per day of our volumes) from our Bruderheim crude-by-rail terminal compared with an average of 57,092 barrels per day (36,433 barrels per day of our volumes) in 2019.

Gross Margin

While market crack spreads are an indicator of margin from processing crude oil into refined products, 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. Our feedstock costs are valued on a FIFO accounting basis.

In the three months ended September 30, 2020, Refining and Marketing gross margin decreased $253 million relative to the third quarter of 2019, primarily due to decreased market crack spreads and lower crude advantage as a result of lower global crude oil and refined product pricing, and decreased crude oil runs.

In the nine months ended September 30, 2020, Refining and Marketing gross margin decreased $1,009 million resulting from decreased market crack spreads and crude advantage as a result of lower global crude oil and refined product pricing, and reduced crude oil runs, partially offset by higher margins on refined products. Our gross margin was positively impacted by approximately $1 million and $4 million for the three and nine months ended September 30, 2020, respectively, due to the weakening of the Canadian dollar relative to the U.S. dollar.

In the three and nine months ended September 30, 2020, the cost of Renewable Identification Numbers ("RINs") was $50 million and $119 million, respectively (2019 – $24 million and $73 million, respectively). RIN costs increased, primarily due to higher pricing, partially offset by lower volume obligations.

Inventory Write-Down (Reversal)

As a result of a decline in refined product and crude oil prices, inventory write-downs of $253 million were recorded related to our refined product and feedstock inventory in the first quarter of 2020. Subsequently we reversed

$20 million of product inventories still on hand due to improved refined product and crude oil prices. For the nine months ended September 30, 2019, we recorded inventory write-downs, net of reversals, of $24 million.

Operating Expense

For the three and nine months ended September 30, 2020, the primary drivers of operating expenses were labour, maintenance and utilities. Operating expenses decreased in the third quarter of 2020 primarily due to lower maintenance costs due to greater maintenance activity in 2019. Operating expenses decreased on a year-to-date basis primarily due to higher maintenance activity in 2019 and lower utility costs.

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 $521 million and $673 million in the three and nine months ended September 30, 2020, respectively (2019 – $65 million and $213 million, respectively). The increase in DD&A is primarily due to an impairment charge of $450 million related to the Borger CGU.

Capital Investment

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
($ millions)	**2020**	2019	**2020**	2019
Wood River Refinery	**41**	41	**96**	96
Borger Refinery	**19**	25	**54**	82
Marketing	**5**	21	**22**	36
Capital Investment	**65**	87	**172**	214

Capital expenditures in the three and nine months ended September 30, 2020 focused primarily on yield enhancement, reliability and maintenance projects, as well as storage infrastructure projects.

In 2020, we expect to invest between $270 million and $300 million and will continue to focus on refining reliability and maintenance, and yield enhancement projects. Our 2020 guidance dated April 1, 2020 is available on our website at cenovus.com.

CORPORATE AND ELIMINATIONS

In the three months ended September 30, 2020, our risk management activities resulted in:

- Unrealized risk management gains of $135 million (2019 – losses of $9 million) due to the realization of settled positions and changes in the commodity prices compared with the end of the prior quarter. This included unrealized losses of $3 million from cross currency interest swaps; and
- A realized foreign exchange hedge gain of $1 million (2019 – loss of $1 million).

On a year-to-date basis, our risk management activities resulted in:

- Unrealized risk management losses of $7 million (2019 – losses of $157 million) due to the realization of settled positions and changes in commodity prices compared with the prices at the end of the prior year; and
- Realized foreign exchange risk management losses of $4 million (2019 – gain of $1 million and loss of $1 million on interest rate swap contracts).

Transactions typically span across periods in order to execute the optimization strategy and these transactions reside across both realized and unrealized risk management.

Expenses

($ millions)	Three Months Ended September 30, 2020	2019	Nine Months Ended September 30, 2020	2019
General and Administrative	**50**	72	**124**	209
Onerous Contract Provisions	**1**	(1)	**-**	(8)
Finance Costs	**145**	138	**391**	376
Interest Income	**(2)**	(3)	**(4)**	(9)
Foreign Exchange (Gain) Loss, Net	**(159)**	88	**168**	(265)
Re-measurement of Contingent Payment	**(31)**	(17)	**(97)**	137
Research Costs	**3**	6	**8**	16
(Gain) Loss on Divestiture of Assets	**(1)**	3	**-**	7
Other (Income) Loss, Net	**(17)**	(11)	**(60)**	(4)
	(11)	275	**530**	459

General and Administrative

Primary drivers of our general and administrative expenses were workforce costs, employee long-term incentive costs, and operating costs associated with our real estate portfolio. In the third quarter, general and administrative ("G&A") expenses decreased $22 million compared with the same period of 2019 primarily due to lower employee long-term incentive costs as a result of the change in share price in the period. On a year-to-date basis, G&A expenses were $85 million lower primarily due to lower employee long-term incentive costs and operating costs associated with our real estate portfolio. Our guidance dated April 1, 2020 is available on our website at cenovus.com.

Finance Costs

Finance costs increased by $7 million in the three months ended September 30, 2020 compared with 2019, due to higher long- and short-term borrowings and higher interest expense on lease liabilities from new contract additions in 2020 compared with 2019. On a year-to-date basis, finance costs increased by $15 million compared with 2019 due to a discount of $25 million on the repurchase of unsecured notes compared with $64 million in 2019, higher short-term borrowings during the period, and a higher interest expense on lease liabilities due to new contract additions in 2020 compared with 2019. This was partially offset by decreased interest on long-term debt due to the lower weighted average interest rate on outstanding debt.

The weighted average interest rate on outstanding debt for the three and nine months ended September 30, 2020 was 4.8 percent (2019 – 5.2 percent and 5.1 percent, respectively).

Foreign Exchange

($ millions)	Three Months Ended September 30, 2020	2019	Nine Months Ended September 30, 2020	2019
Unrealized Foreign Exchange (Gain) Loss	**(140)**	88	**229**	(560)
Realized Foreign Exchange (Gain) Loss	**(19)**	-	**(61)**	295
	(159)	88	**168**	(265)

In the third quarter of 2020 and on a year-to-date basis, unrealized foreign exchange gains of $140 million and losses of $229 million, respectively, 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 September 30, 2020 was stronger compared with June 30, 2020, resulting in unrealized gains and three percent 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 from ConocoPhillips of 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 $46 million as at September 30, 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 and nine months ended September 30, 2020, a non-cash re-measurement gain of $31 million and $97 million, respectively, was recorded.

Average WCS forward pricing for the remaining term of the contingent payment is $37.41 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately $36.50 per barrel and $39.20 per barrel.

Other (Income) Loss, Net

The Government of Canada passed the CEWS as part of its COVID-19 Economic Response Plan. The program is effective from March 15, 2020 to the summer of 2021. For the three and nine months ended September 30, 2020, we recorded $9 million and $40 million, respectively, in other income from the CEWS program.

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 three months ended September 30, 2020 was $27 million (2019 – $24 million) and $104 million on a year-to-date basis (2019 – $81 million).

Income Tax

($ millions)	Three Months Ended September 30, **2020**	2019	Nine Months Ended September 30, **2020**	2019
Current Tax				
Canada	**(1)**	10	**(3)**	22
United States	**-**	(4)	**1**	1
Current Tax Expense (Recovery)	**(1)**	6	**(2)**	23
Deferred Tax Expense (Recovery)	**(177)**	46	**(656)**	(790)
Total Tax Expense (Recovery)	**(178)**	52	**(658)**	(767)

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.

For the three and nine months ended September 30, 2020, a deferred tax recovery was recorded due to an impairment of the Borger CGU and current period operating losses that will be carried forward, excluding unrealized foreign exchange gains and losses on long-term debt.

In the nine months ended September 30, 2019, the Government of Alberta enacted a reduction in the provincial corporate tax rate from 12 percent to eight percent over four years. As a result, we recorded a deferred income tax recovery of $663 million. In addition, we recorded a deferred income tax recovery of $387 million due to an internal restructuring of our U.S. operations resulting in a step-up in the tax basis of our refining assets and current tax expense of $23 million was recorded on current year 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 $51 million for 2020 focused primarily on supporting investments in technology and infrastructure to modernize our workplace, improve our cost structure and reduce costs and risk.

In 2020, we expect to invest up to $55 million. Our guidance dated April 1, 2020 is available on our website at cenovus.com.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended September 30, 2020	2019	Nine Months Ended September 30, 2020	2019
Cash From (Used in)				
Operating Activities	**732**	834	**23**	2,545
Investing Activities	**(136)**	(343)	**(663)**	(966)
Net Cash Provided (Used) Before Financing Activities	**596**	491	**(640)**	1,579
Financing Activities	**(322)**	(100)	**901**	(1,888)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(22)**	(18)	**(43)**	(35)
Increase (Decrease) in Cash and Cash Equivalents	**252**	373	**218**	(344)

	September 30, 2020	December 31, 2019
Cash and Cash Equivalents	**404**	186
Debt	**7,934**	6,699

As at September 30, 2020, we were in compliance with all of the terms of our debt agreements.

Cash From (Used in) Operating Activities

For both the three and nine months ended September 30, 2020, cash generated by operating activities decreased mainly due to lower Operating Margin, partially offset by higher other income due to CEWS, and lower current taxes, 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 $754 million at September 30, 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 for the three and nine months ended September 30, 2020 was lower compared with 2019 primarily due to decreased capital investment.

Cash From (Used in) Financing Activities

In the third quarter of 2020, cash proceeds from the issuance of US$1.0 billion in 5.375 percent senior unsecured notes due in 2025 and cash on hand were used to repay $1.4 billion of borrowings on our committed credit facility and $159 million of short-term borrowings.

Total debt, including short-term borrowings, as at September 30, 2020 was $7,934 million (December 31, 2019 – $6,699 million). We have no principal payments due on our long-term debt until August 2022.

During the nine months ended September 30, 2020, we:

- Repurchased US$100 million of unsecured notes for cash of US$81 million in the first quarter;
- Borrowed $1.4 billion on our credit facility in the second quarter; and
- Used the proceeds from the issuance of US$1.0 billion in 5.375 percent senior unsecured notes due in 2025 to repay $1.4 billion of borrowings on our committed credit facility in the third quarter.

During the nine months ended September 30, 2019, we repaid US$1.3 billion of unsecured notes for cash consideration of US$1.2 billion ($1.6 billion).

Dividends

On April 2, 2020 we announced the temporary suspension of our dividend in response to the low global crude oil price environment. The continued suspension of our dividend resulted in no dividends paid in the third quarter of 2020 (2019 – $0.05 per common share or $60 million). In the nine months ended September 30, 2020, we paid dividends of $0.0625 per common share or $77 million (2019 – $0.15 per common share or $183 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Available Sources of Liquidity

The following sources of liquidity are available at September 30, 2020:

($ millions)	Term	Amount Available
Cash and Cash Equivalents	**Not applicable**	**404**
Committed Credit Facilities		
Revolving Credit Facility – Tranche A	**November 2023**	**3,300**
Revolving Credit Facility – Tranche B	**November 2022**	**1,200**
Liquidity Facility	**April 2021**	**1,100**
Uncommitted Demand Facilities		
Cenovus Energy Inc.	**Not applicable**	**600**
WRB Refining LP (Cenovus's proportionate share)	**Not applicable**	**63**

In light of the current challenging economic conditions, we expect to fund our near-term cash requirements through cash from operating activities and 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 cost and availability of borrowing, and access to sources of liquidity and capital is dependent on current credit ratings as determined by independent rating agencies and market conditions.

Committed Credit Facilities

We have total committed credit facilities of $5.6 billion. We have a committed revolving 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. During the second quarter, we added a committed credit facility with capacity of $1.1 billion, with a term of 364 days that is renewable for one year at our request and upon approval by the lenders, to further support our financial resilience in the current market environment. As at September 30, 2020, no amounts were drawn on our committed credit facilities.

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 September 30, 2020, the Company had drawn no amounts (December 31, 2019 - $nil) on these facilities and there were outstanding letters of credit aggregating to $457 million (December 31, 2019 - $364 million).

WRB Refining LP has uncommitted demand facilities of US$300 million (the Company's proportionate share - US$150 million) available to cover short-term working capital requirements. As at September 30, 2020, US$205 million was drawn on the facilities, of which US$103 million ($137 million) was the Company's proportionate share (December 31, 2019 – $nil).

Base Shelf Prospectus

Cenovus has in place a base shelf prospectus which expires in October 2021. During the third quarter, we completed the issuance of US$1.0 billion in 5.375 percent senior unsecured notes due in 2025 under our short form base shelf prospectus. As at September 30, 2020, US$4.0 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.

	September 30, 2020	December 31, 2019
Net Debt to Capitalization [1] (percent)	**31**	25
Net Debt to Adjusted EBITDA (times)	**8.4x**	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 facilities 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 agreements.

As at September 30, 2020, Cenovus's Net Debt to Adjusted EBITDA was 8.4 times. Net Debt to Adjusted EBITDA increased compared with December 31, 2019 as a result of a weaker Canadian dollar, an increase in our borrowings, as mentioned in the Cash From (Used In) Financing Activities above, and a reduction in our trailing twelve-month adjusted EBITDA.

Under the committed credit facilities, Cenovus is required to maintain a debt to capitalization ratio, as defined in the agreement, not to exceed 65 percent. We were well below this limit at September 30, 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 September 30, 2020, there were approximately 1,229 million common shares outstanding (2019 – 1,229 million common shares).

Refer to Note 26 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 September 30, 2020	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares [1]	**1,228,870**	**N/A**
Stock Options	**30,795**	**20,576**
Other Stock-Based Compensation Plans	**18,730**	**1,502**

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

Capital Investment Decisions

Our 2020 capital program is forecast to be between $750 million and $850 million. Planned capital spending has been reduced from 2019 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 while remaining focused on committed capital priorities including safe and reliable operations and sustaining and maintenance capital for our existing business operations.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
($ millions)	**2020**	2019	**2020**	2019
Adjusted Funds Flow [1]	**414**	928	**(194)**	3,015
Total Capital Investment	**148**	294	**599**	859
Free Funds Flow [1] [2]	**266**	634	**(793)**	2,156
Cash Dividends	**-**	60	**77**	183
	266	574	**(870)**	1,973

(1) The comparative period has been reclassified to conform with current period treatment of non-cash inventory write-downs and reversals.
(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 have adjusted our discretionary capital plans in 2020, including temporarily suspending our quarterly cash dividend. This should allow the Company to fund a portion of its capital program with internally generated cash flows, cash 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 September 30, 2020 interim Consolidated Financial Statements and December 31, 2019 Consolidated Financial Statements.

As at September 30, 2020, total commitments were $23 billion, of which $22 billion are for various transportation and storage commitments. Transportation commitments include $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 September 30, 2020, there were outstanding letters of credit aggregating $457 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 September 30, 2020, the estimated fair value of the contingent payment was estimated to be $46 million. As at September 30, 2020, no amount was payable under the agreement. 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, physical distancing measures 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. While economies have started to re-open, a resurgence in cases of COVID-19 has occurred in certain locations and the risk of a resurgence in other locations remains high. This creates ongoing uncertainty that could result in restrictions on movement and businesses being re-imposed or imposed on a stricter basis, which could negatively impact demand for commodities and commodity prices and negatively impact our business, results of operations and financial condition. 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. 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 disruptions 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 disruptions 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;
- Crude oil storage constraints resulting in the curtailment or shutting in of production;
- 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 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 taken to contain COVID-19 or treat its impact, and how quickly and to what extent normal economic and operating conditions can resume. The potential impacts of COVID-19 to our business, results of operations and financial condition could be more significant in upcoming periods as compared with the first three-quarters 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 implemented physical distancing measures, and had directed 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. Earlier this month, we lifted our mandatory work from home measure to open our modified workspaces in the Calgary offices to staff again, with workplace safety plans and protocols in place. Increases in staff levels at sites and offices has been and will continue to be achieved in accordance with guidance received from the Federal and Provincial governments and public health officials.

Excess Crude Oil Supply Risk

It is not known how long low commodity price 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. While OPEC members agreed to certain production cuts through April 2022 amid the global demand reduction caused by the pandemic, there can be no assurances that OPEC members and other oil exporting nations will continue to agree to actions to stabilize oil prices. Uncertainty regarding the future actions of such nations may lead to increased commodity price volatility. See "Commodity Prices" below.

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 27 and 28 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 September 30,					
	2020			2019		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**137**	**(135)**	**2**	(7)	9	2
Refining	**2**	**(3)**	**(1)**	(3)	-	(3)
Cross Currency Interest Rate	**-**	**3**	**3**	-	-	-
Foreign Exchange	**(1)**	**-**	**(1)**	1	-	1
(Gain) Loss on Risk Management	**138**	**(135)**	**3**	(9)	9	-
Income Tax Expense (Recovery)	**(36)**	**33**	**(3)**	2	(1)	1
(Gain) Loss on Risk Management, After Tax	**102**	**(102)**	**-**	(7)	8	1

	Nine Months Ended September 30,					
	2020			2019		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**228**	**8**	**236**	38	151	189
Refining	**(6)**	**(1)**	**(7)**	(14)	1	(13)
Interest Rate	**-**	**-**	**-**	1	7	8
Cross Currency Interest Rate	**-**	**-**	**-**	-	-	-
Foreign Exchange	**4**	**-**	**4**	(1)	(2)	(3)
(Gain) Loss on Risk Management	**226**	**7**	**233**	24	157	181
Income Tax Expense (Recovery)	**(55)**	**(2)**	**(57)**	(7)	(38)	(45)
(Gain) Loss on Risk Management, After Tax	**171**	**5**	**176**	17	119	136

For Cash Flow derivatives, we incurred a realized loss due to the settlement of benchmark prices relative to our risk management contract prices. For Optimization derivatives, the realized loss was from our decisions to store rather than sell our physical crude oil and condensate volumes. Cenovus uses its marketing and transportation initiatives, including storage and pipeline assets to optimize product mix, delivery points, transportation commitments and customer diversification, to inventory physical positions. At the time we make the decision to store crude oil and condensate volumes, the prices available for future periods we plan to sell in can be locked in and the improved margin realized in the future periods, which are superior to short-term prices. The risk management gains and losses offset corresponding fluctuations in revenues generated from the underlying physical sales.

Unrealized gains of $135 million in the three months ended September 30, 2020 and unrealized losses of $8 million on a year-to-date basis, were recorded on our crude oil financial instruments primarily due to changes in commodity prices compared with prices at the end of the prior quarter and prior year, respectively, and the realization of settled positions.

Transactions typically span across periods in order to execute the optimization strategy, and these transactions reside across both realized and unrealized risk management.

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 of COVID-19 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, including refined product, and the decline in market crack spreads 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 of a liability and to estimate the future amount of the liability and uses a credit-adjusted discount rate to present value the estimated future cash flows required to settle the obligation. Market volatility has 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. There is increased measurement uncertainty related to the expected total annual earnings or expected earnings due to the reduced demand and fluctuation of commodity prices as a result of COVID-19.

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 nine months ended September 30, 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 nine months ended September 30, 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 September 30, 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

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

We expect the remainder of 2020 and much of 2021 to be a challenging time for our industry and the global economy in general due to the impacts of COVID-19. We expect continued crude oil and refined products demand and price recovery over the longer term as economies reopen and rebound from the negative impacts of the pandemic. However, with the continued uncertainty around COVID-19 and the scale of resurgence of COVID-19 cases, we anticipate crude oil and refined products demand to be volatile throughout 2020 and into 2021 with recovery dependent on the success of economic relaunches. We continue to anticipate that an increase in demand for refined products, particularly motor fuels, will be an early indicator of recovery from the impact of COVID-19. Our top priority will be to maintain the strength of our balance sheet. We have ample liquidity, top-tier assets which we are able to effectively manage to respond to price signals, one of the lowest cost structures in the industry and have demonstrated our ability to reduce discretionary capital, all of which should allow us to continue to adapt to these challenges.

We continue to monitor the overall market dynamics amidst the COVID-19 situation in assessing how we manage our Oil Sands production levels. Our assets can respond to market signals and ramp up production to produce above government mandated production curtailment levels dependent on the availability of production credits. This includes the potential to ramp up our temporarily suspended crude-by-rail program to generate Special Production Allowance ("SPA") program curtailment relief or purchase third-party credits. Our decisions around production levels will be focused on maximizing the value we receive for our products. We expect our 2020 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.

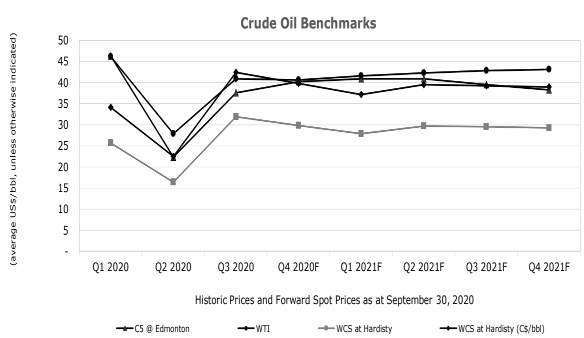
Given the challenges faced by our industry and the global economy, achieving cumulative free funds flow of approximately $11 billion through 2024, as disclosed in our news release dated October 2, 2019 in respect of our five-year business plan, is uncertain and continues to be evaluated, and may be impacted by future events.

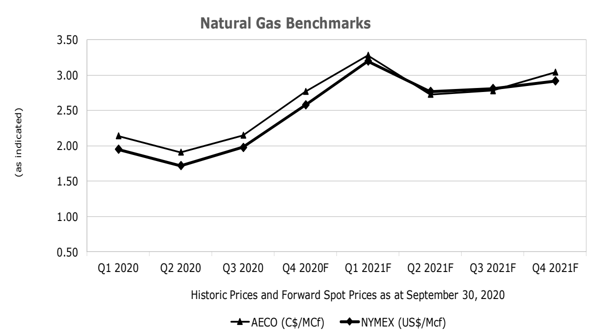
Commodity Prices Underlying our Financial Results

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 and demand 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 crude demand destruction as a result of COVID-19 and the pace and timing of recovery;
- The degree to which OPEC+ members (including Russia) continue to maintain crude oil production cuts;
- We expect that the WTI-WCS differential in Alberta will remain largely tied to the extent to which supply cuts are sustained, 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
- We expect refining market crack spreads in 2020 to remain weak relative to previous years as a result of significantly reduced refined products demand due to COVID-19. Refining market crack spreads are expected to continue to fluctuate, adjusting for seasonal trends and refining run cuts in North America.

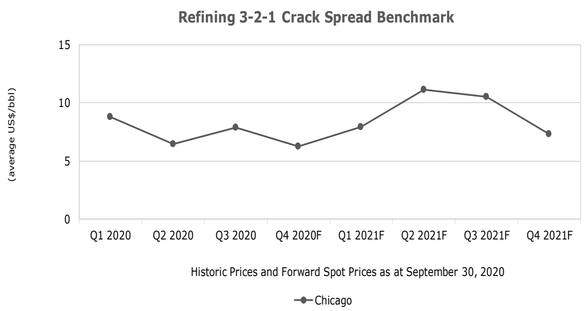
Natural gas and NGLs production associated with our Conventional assets provide improved upstream integration for the fuel, solvent and blending requirements at our Oil Sands operations.

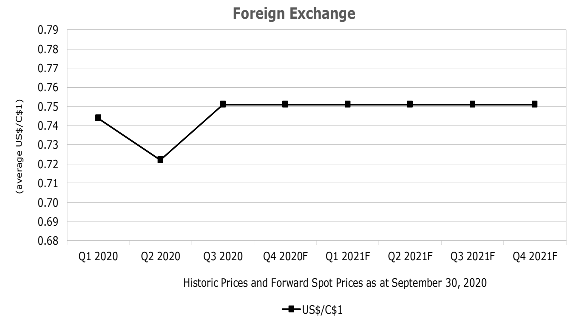




Natural gas prices have been challenged due to weaker demand as a result of COVID-19, but the forward curve is showing that the market expects AECO prices to rebound into 2021. Seasonal demand is expected to support pricing in the fourth quarter of 2020. Production declines from both associated gas and dry gas, along with rebounding U.S. demand and liquified natural gas exports should tighten North American gas fundamentals further in 2021 and result in stronger prices than 2020 on an annual basis.

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 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 – using our existing firm service commitments for takeaway capacity and 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 rates in response to pipeline capacity constraints, voluntary and 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 low 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 focused on disciplined capital investment, improved market access, and continued cost leadership to achieve margin improvement and environmental benefits.

Maintaining Financial Resilience

We have top-tier assets, one of the lowest cost structures in our industry and a strong balance sheet, all of which position 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 for the remainder of 2020 and into 2021.

Disciplined Capital Investment

As a result of the collapse of oil prices and COVID-19, we updated our 2020 guidance on 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. 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 September 30, 2020, our Net Debt position was $7.5 billion. We expect to fund our near-term cash requirements through cash from operating activities, 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. Through a combination of cash on hand and available capacity on our committed credit facilities and demand facilities, we have approximately $6.6 billion of liquidity. In addition, WRB has available capacity of approximately $63 million, for Cenovus's proportionate share, on its demand facilities.

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.

Shareholder Returns

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

Market Access

Market access constraints for Canadian crude oil production continue to be challenging. 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. We have completed the temporary ramp down of our crude-by-rail program but expect to ramp it back up when the underlying pricing fundamentals support its continuation.

Cost Leadership

On April 1, 2020 we updated our guidance. We reduced our planned 2020 capital investment and are forecasting operating cost reductions of about $100 million and G&A cost reductions of about $50 million compared with our initial 2020 capital budget released in December 2019. 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", "continue", "could", "drive", "enhance", "ensure", "estimate", "expect", "focus", "forecast", "forward", "future", "guidance", "maintain", "may", "objective", "outlook", "plan", "position", "potential", "priority", "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; anticipated receipt of required regulatory, court and securityholder approvals for the Husky Transaction and other customary closing conditions; focus on maximizing shareholder value through cost leadership and realizing the best margins for our products; maintaining liquidity and preserving a resilient balance sheet by reducing spending, while maintaining safe and reliable operations; longer-term focus on sustainably growing shareholder returns and reducing Net Debt as well as continuing to integrate ESG considerations into our business plan; maintaining a strong balance sheet will help Cenovus navigate through commodity price volatility; evaluating disciplined investment in our portfolio against dividends, share repurchases and achieving and maintaining the optimal debt level while targeting investment grade status; focusing investment on areas where we believe we have the greatest competitive advantage; 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; our reduced 2020 capital investment plan, operating cost reductions and G&A reductions enhances our financial resilience and financial capability to maintain our base business, deliver safe and reliable operations and to continue to challenge our cost structure in the face of these unprecedented conditions; ample liquidity and runway to sustain operations through a prolonged market downturn; anticipated volatility of demand and crude oil prices through 2020 and into 2021 as a result of continued uncertainty around COVID-19, with crude oil and refined products demand and recovery dependent on the success of economic relaunches and the overall supply and demand balance; 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; increases in staff levels at sites and offices will continue to be achieved in accordance with guidance received from the Federal and Provincial governments and public health officials; expected timing for oil sands expansion phases projections for 2020 and future years and our plans and strategies to realize such projections; expectations to ramp up crude-by-rail program when the underlying pricing fundamentals support its continuation; potential to ramp up crude-by-rail program to generate SPAs or purchase third-party credits to produce above curtailment; the reduction of transportation costs caused by the temporary suspension of the crude-by-rail program; reaching a broader customer base; 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, including decisions pertaining to new projects and phases; 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, storage 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 general outlook for light crude oil prices will be tied primarily to the supply and demand response to the current uncertain price environment, the impact of oversupply, and global demand impacts amid COVID-19 concerns; our expectation that the WTI-WCS differential in Alberta will remain largely tied to the extent to which supply cuts are sustainable, 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; our expectation that in 2020 refining market crack spreads will remain weak relative to previous years as a result of significantly reduced refined products demand due to COVID-19; our expectation that our capital investment and near-term cash requirements will be funded through cash from operating activities and 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; statements about our debt level as we manage through the low commodity price environment; expected reserves; focus on mid-term strategies to broaden market access for our crude oil production; supporting 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; 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; 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$44/bbl WCS in a normalized demand market; the satisfaction of the conditions to closing of the Husky Transaction in a timely manner and completion of the arrangement on the expected terms; our forecast production volumes are subject to potential further ramp down of production based on business and market conditions; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; achievement of further cost reductions and sustainability thereof; applicable royalty regimes, including expected royalty rates; future improvements in availability of product transportation capacity; underlying pricing fundamentals will once again support the continuation of the crude-by-rail program; suspension of the crude-by-rail program will lower transportation costs; increase to our share price and market capitalization over the long term; opportunities to repurchase shares for cancellation at prices acceptable to us; cash flows, cash balances on hand and access to credit and demand facilities being sufficient to fund capital investments; foreign exchange rate, including with respect to our US$ 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 and/or storage capacity has improved and crude oil differentials have narrowed; the Government of Alberta's mandatory production curtailment will continue to 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, the potential start-up of the 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 and financial hedge transactions to partially mitigate a portion of our WCS crude oil volumes against wider differentials; production declines from both associated gas and dry gas, along with rebounding U.S. demand and liquified natural gas exports should tighten North American gas fundamentals further in 2021 and result in stronger prices than 2020 on an annual basis; 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: the ability of Cenovus and Husky to receive, in a timely manner, the necessary regulatory, court, securityholder, stock exchange and other third-party approvals; the ability of Cenovus and Husky to satisfy, in a timely manner, the other conditions to the closing of the Husky Transaction; interloper risk; the ability to complete the transaction on the terms contemplated by the arrangement agreement between Cenovus and Husky, and other agreements, including the support agreements or at all; 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; a resurgence in cases of COVID-19, which has occurred in certain locations and the possibility of which in other locations remains high and creates ongoing uncertainty that could result in restrictions to contain the virus being re-imposed or imposed on a more strict basis, including restrictions on movement and businesses; the extent to which COVID-19 impacts the global economy and harms commodity prices; the extent to which COVID-19 and fluctuations in commodity prices associated with COVID-19 impacts our business, results of operations and financial condition, all of which will depend on future developments that are highly uncertain and difficult to predict, including, but not limited to the duration and spread of the pandemic, its severity, the actions taken to contain COVID-19 or treat its impact and how quickly economic activity normalizes; the success of our new COVID-19 workplace policies and the return of our people to our workplaces; 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, 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; our ability to achieve lower transportation costs as a result of temporarily suspending the crude-by-rail program; 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 and/or storage 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 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 relationships 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, maintaining or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining 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 or storage capacity; 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 September 30, 2020 ($ millions)	Oil Sands (1)	Conventional (1) (2)	Total Upstream	Condensate	Inventory	Internal Usage (3)	Other	Total Upstream
Gross Sales	2,195	156	2,351	(747)	-	(70)	(12)	1,522
Royalties	129	24	153	-	-	-	-	153
Transportation and Blending	1,015	21	1,036	(747)	6	-	-	295
Operating	276	81	357	-	-	(70)	(7)	280
Inventory Write-Down (Reversal)	-	-	-	-	-	-	-	-
Netback	775	30	805	-	(6)	-	(5)	794
(Gain) Loss on Risk Management	137	-	137	-	-	-	-	137
Operating Margin	638	30	668	-	(6)	-	(5)	657

	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Three Months Ended September 30, 2019 ($ millions)	Oil Sands (1)	Conventional (1) (2)	Total Upstream	Condensate	Inventory	Internal Usage (3)	Other	Total Upstream
Gross Sales	2,722	131	2,853	(924)	-	(27)	(14)	1,888
Royalties	336	(4)	332	-	-	-	-	332
Transportation and Blending	1,249	20	1,269	(924)	-	-	-	345
Operating	227	77	304	-	-	(27)	(8)	269
Netback	910	37	947	-	-	-	(6)	941
(Gain) Loss on Risk Management	(7)	-	(7)	-	-	-	-	(7)
Operating Margin	917	37	954	-	-	-	(6)	948

	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Nine Months Ended September 30, 2020 ($ millions)	Oil Sands (1)	Conventional (1) (2)	Total Upstream	Condensate	Inventory	Internal Usage (3)	Other	Total Upstream
Gross Sales	5,287	451	5,738	(2,599)	-	(203)	(41)	2,895
Royalties	193	28	221	-	6	-	-	227
Transportation and Blending	3,268	63	3,331	(2,599)	285	-	-	1,017
Operating	785	246	1,031	-	25	(203)	(23)	830
Inventory Write-Down (Reversal)	316	-	316		(316)			-
Netback	725	114	839	-	-	-	(18)	821
(Gain) Loss on Risk Management	228	-	228	-	-	-	-	228
Operating Margin	497	114	611	-	-	-	(18)	593

	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Nine Months Ended September 30, 2019 ($ millions)	Oil Sands (1)	Conventional (1) (2)	Total Upstream	Condensate	Inventory	Internal Usage (3)	Other	Total Upstream
Gross Sales	8,179	501	8,680	(2,961)	-	(140)	(51)	5,528
Royalties	827	20	847	-	-	-	-	847
Transportation and Blending	3,736	62	3,798	(2,961)	-	-	-	837
Operating	771	257	1,028	-	-	(140)	(27)	861
Netback	2,845	161	3,006	-	-	-	(24)	2,982
(Gain) Loss on Risk Management	38	-	38	-	-	-	-	38
Operating Margin	2,807	161	2,968	-	-	-	(24)	2,944

(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

Three Months Ended September 30, 2020 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements (1): Total Oil Sands
Gross Sales	605	842	1,447	-	747	-	1	2,195
Royalties	36	93	129	-	-	-	-	129
Transportation and Blending	125	149	274	-	747	(6)	-	1,015
Operating	131	143	274	-	-	-	2	276
Inventory Write-Down (Reversal)	-	-	-	-	-	-	-	-
Netback	313	457	770	-	-	6	(1)	775
(Gain) Loss on Risk Management	54	83	137	-	-	-	-	137
Operating Margin	259	374	633	-	-	6	(1)	638

Three Months Ended September 30, 2019 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements (1): Total Oil Sands
Gross Sales	879	917	1,796	-	924	-	2	2,722
Royalties	147	189	336	-	-	-	-	336
Transportation and Blending	196	129	325	-	924	-	-	1,249
Operating	119	106	225	-	-	-	2	227
Netback	417	493	910	-	-	-	-	910
(Gain) Loss on Risk Management	(3)	(4)	(7)	-	-	-	-	(7)
Operating Margin	420	497	917	-	-	-	-	917

Nine Months Ended September 30, 2020 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements (1): Total Oil Sands
Gross Sales	1,244	1,438	2,682	-	2,599	-	6	5,287
Royalties	67	132	199	-	-	(6)	-	193
Transportation and Blending	523	431	954	-	2,599	(285)	-	3,268
Operating	404	399	803	-	-	(25)	7	785
Inventory Write-Down (Reversal)	-	-	-			316		316
Netback	250	476	726	-	-	-	(1)	725
(Gain) Loss on Risk Management	96	132	228	-	-	-	-	228
Operating Margin	154	344	498	-	-	-	(1)	497

Nine Months Ended September 30, 2019 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements (1): Total Oil Sands
Gross Sales	2,564	2,645	5,209	-	2,961	-	9	8,179
Royalties	356	471	827	-	-	-	-	827
Transportation and Blending	467	308	775	-	2,961	-	-	3,736
Operating	394	369	763	-	-	-	8	771
Netback	1,347	1,497	2,844	-	-	-	1	2,845
(Gain) Loss on Risk Management	15	23	38	-	-	-	-	38
Operating Margin	1,332	1,474	2,806	-	-	-	1	2,807

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

Conventional [1]

Three Months Ended September 30, 2020 ($ millions)	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements[2]
	Total	Other[3]	Total Conventional
Gross Sales	145	11	156
Royalties	24	-	24
Transportation and Blending	21	-	21
Operating	76	5	81
Netback	24	6	30
(Gain) Loss on Risk Management	-	-	-
Operating Margin	24	6	30

Three Months Ended September 30, 2019 ($ millions)	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements[2]
	Total	Other[3]	Total Conventional
Gross Sales	119	12	131
Royalties	(4)	-	(4)
Transportation and Blending	20	-	20
Operating	71	6	77
Production and Mineral Taxes	1	-	1
Netback	31	6	37
(Gain) Loss on Risk Management	-	-	-
Operating Margin	31	6	37

Nine Months Ended September 30, 2020 ($ millions)	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements[2]
	Total	Other[3]	Total Conventional
Gross Sales	416	35	451
Royalties	28	-	28
Transportation and Blending	63	-	63
Operating	230	16	246
Netback	95	19	114
(Gain) Loss on Risk Management	-	-	-
Operating Margin	95	19	114

Nine Months Ended September 30, 2019 ($ millions)	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements[2]
	Total	Other[3]	Total Conventional
Gross Sales	459	42	501
Royalties	20	-	20
Transportation and Blending	62	-	62
Operating	238	19	257
Production and Mineral Taxes	1	-	1
Netback	138	23	161
(Gain) Loss on Risk Management	-	-	-
Operating Margin	138	23	161

(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 September 30, 2020	2019	Nine Months Ended September 30, 2020	2019
Oil Sands				
Foster Creek	**158,280**	162,199	**166,180**	159,108
Christina Lake	**238,140**	192,929	**222,012**	182,680
Total Oil Sands (barrels per day)	**396,420**	355,128	**388,192**	341,788
Conventional (1)				
Total Liquids	**25,702**	26,104	**27,352**	26,835
Natural Gas (MMcf per day)	**360**	407	**382**	432
Total Conventional (BOE per day)	**85,713**	93,901	**91,062**	98,807
Sales before Internal Consumption	**482,133**	449,029	**479,254**	440,595
Less: Internal Consumption (2) (MMcf per day)	**(321)**	(304)	**(333)**	(314)
Total Sales (2) (BOE per day)	**428,659**	398,304	**423,677**	388,237

(1) This segment was previously referred to as the Deep Basin segment.
(2) Less natural gas volumes used for internal consumption by the Oil Sands segment.