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

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", the "Company", or "Cenovus", and means Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) as at December 31, 2020 and, for greater certainty, unless otherwise specified or the context otherwise requires, excludes Husky Energy Inc. ("Husky") and the subsidiaries of, and partnership interests held by Husky and its subsidiaries, dated February 8, 2021, should be read in conjunction with our December 31, 2020 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). All of the information and statements contained in this MD&A are made as of February 8, 2021, unless otherwise indicated. This MD&A 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 Audit Committee of the Cenovus Board of Directors (the "Board") reviewed and recommended the MD&A for approval by the Board, which occurred on February 8, 2021. 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.

On January 1, 2021, pursuant to a plan of arrangement under the Business Corporations Act (Alberta), Husky became a wholly-owned subsidiary of Cenovus. In connection with its acquisition of Husky and in accordance with applicable securities laws, Cenovus will be filing a business acquisition report containing the pro forma financial statements of the combined company as of December 31, 2020. Additional information concerning Husky's business and assets as of December 31, 2020 may be found in the annual information form of Husky dated February 8, 2021 for the year ended December 31, 2020 (the "Husky AIF") and Husky's management's discussion and analysis of the financial and operating results for the year ended December 31, 2020 (the "Husky MD&A"), each of which is filed and available on SEDAR under Husky's profile at sedar.com.

Basis of Presentation

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

Non-GAAP Measures and Additional Subtotals

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

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

OVERVIEW OF CENOVUS

We are a Canadian-based integrated oil and natural gas company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. At December 31, 2020, prior to the close of the transaction with Husky on January 1, 2021, as described below, our operations included 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 in 2020. We also conducted marketing activities and have ownership interest in refining operations in the United States ("U.S."). The refineries processed an average of 372,000 gross barrels per day of crude oil feedstock into an average of 385,000 gross barrels per day of refined products in 2020.

For a description of our operations in 2020, refer to the Reportable Segments section of this MD&A.

Cenovus and Husky Arrangement

On October 24, 2020, Cenovus and Husky entered into a definitive agreement to combine the two companies in an all-stock transaction to create a resilient Canadian-based integrated energy company. The transaction was accomplished through a plan of arrangement ("the Arrangement") pursuant to which Cenovus acquired all the issued and outstanding common shares of Husky in exchange for common shares and common share purchase warrants of Cenovus. In addition, all of the issued and outstanding Husky preferred shares were exchanged for Cenovus preferred shares with substantially identical terms. The Arrangement closed on January 1, 2021 and we continue to operate as Cenovus, trade under the Cenovus name, and remain headquartered in Calgary, Alberta.

The Arrangement combines high quality oil sands and heavy oil assets with extensive trading, supply and logistics infrastructure, and downstream infrastructure, creating opportunities to optimize the margin captured across the heavy oil value chain. With the combination of processing capacity and market access outside Alberta for the majority of the Company's oil sands and heavy oil production, exposure to Alberta heavy oil price differentials is reduced while maintaining exposure to global commodity prices. The combined company has a cost-and-market-advantaged asset portfolio, which prioritizes free funds flow generation, balance sheet strength and returns to shareholders.

The combined company is the third largest Canadian oil and natural gas producer and the second largest Canadian-based refiner and upgrader with operations in Canada, the U.S. and the Asia Pacific region. Our operations include oil sands projects in northern Alberta, thermal and conventional crude oil and natural gas projects across Western Canada, crude oil production offshore Newfoundland and Labrador and natural gas and liquids production offshore China and Indonesia. Our downstream operations include upgrading, refining and marketing operations in Canada and the U.S.

Management is in the process of finalizing the determination of the operating and reporting segments for the Company. It is anticipated that the Company's business will be conducted predominately through an upstream and downstream segment. Management continues to evaluate how the segments may be presented and will make a final determination during the first quarter of 2021.

The Upstream business is anticipated to be reported as follows:

- **Oil Sands,** includes the development and production of heavy oil and bitumen in northeast Alberta and Saskatchewan. Cenovus's oil sands assets include Foster Creek, Christina Lake, Sunrise and Tucker oil sands projects, as well as Lloydminster Thermal and Cold and Enhanced Oil Recovery assets.
- **Conventional,** includes the operations from conventional oil and natural gas production, including processing operations in the Deep Basin and other parts of Western Canada.
- **Offshore,** includes the offshore operations, exploration and development activities in the Asia Pacific region and Atlantic Canada region.

The Downstream business is anticipated to be reported under the following segments:

- **Canadian Manufacturing,** includes Cenovus's owned and operated upgrader and asphalt refinery in Lloydminster, the owned and operated crude-by-rail terminal and two ethanol plants.
- **Retail,** includes the Canadian retail, commercial and wholesale channels.
- **U.S. Manufacturing,** includes the U.S. operations of wholly owned refineries in Lima and Superior, the jointly owned Wood River and Borger refineries with operator Phillips 66 and the jointly owned Toledo refinery with BP Products North America Inc. as operator.

Our Strategy

Our strategy remains focused on maximizing shareholder value through cost leadership and realizing the best margins for our products. Our diverse and integrated portfolio will help us to deliver stable cash flow through price cycles while maintaining safe and reliable operations. We remain focused on sustainably growing shareholder returns and reducing Net Debt. The diverse portfolio of projects and other opportunities across our business are expected to allow us to leverage increased economies of scale to better compete in an increasingly consolidated energy industry. We believe that maintaining a strong balance sheet will help Cenovus navigate through commodity price volatility. We plan to use our capital allocation framework to evaluate disciplined investments in our portfolio against dividends, share repurchases and managing to the optimal debt level while maintaining investment grade status. Our investment focus will be on areas where we believe we have the greatest competitive advantage to generate the highest returns and incorporate Environmental, Social and Governance ("ESG") considerations into our business plan.

On January 28, 2021 we announced the 2021 budget for the combined company focused on sustaining capital and generating free funds flow to strengthen the balance sheet, accelerated by capturing transaction-related synergies across the organization. 2021 guidance dated January 28, 2021 is available on our website at cenovus.com.

Additional information on the Arrangement is available in our news releases, dated October 25, 2020 and January 4, 2021 available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com, in our joint management information circular with Husky dated November 9, 2020 available on SEDAR and EDGAR, and in our material change reports dated November 3, 2020 and January 11, 2021 available on SEDAR and EDGAR. The information in this MD&A, as it relates to our operations for 2020, does not reflect the closing of the Arrangement, unless otherwise noted.

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

2020 was a challenging year due to the significant decrease in crude oil demand due to COVID-19 resulting in the low global oil price environment.

During the first half of the year, there was a significant reduction in crude oil demand 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 a low of US$10.01 per barrel, excluding a historic one-day low of negative US$37.63 per barrel on April 20, 2020.

In light of these unprecedented conditions, we reduced our planned capital investment plan, operating costs, and general and administrative ("G&A") costs. We remained focused on enhancing our financial resilience and financial capability to maintain our base business and deliver safe and reliable operations.

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, governments began to ease off on some of the measures taken to contain the pandemic increasing demand for crude oil, which helped increase crude oil prices.

In the second half of 2020, crude oil prices improved from the low prices impacting the first half of the year; however, prices continued to be volatile due to market responses to COVID-19 and OPEC crude oil production output decisions. Volatility of crude oil prices continued in the fourth quarter, responding to news of COVID-19 vaccine breakthroughs, continued OPEC and OPEC+ output restrictions, and government responses to the resurgence of COVID-19 cases.

We believe that we have ample liquidity and runway to sustain our operations through a prolonged market downturn. Following the closing of the Arrangement on January 1, 2021, Cenovus has $8.5 billion in committed credit facilities, with $2.0 billion maturing in June 2022, $1.2 billion maturing in November 2022, $3.3 billion maturing in November 2023, and $2.0 billion maturing in March 2024. 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 governing the credit facilities, not to exceed 65 percent. As at December 31, 2020, the Company was well below this limit and we expect to continue to be in compliance with all financial covenants under the credit facilities.

The Provincial and Federal governments have recognized the serious economic impacts of COVID-19 and have taken steps to provide various programs, such as the Canada Emergency Wage Subsidy ("CEWS") program. During the year 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 mitigate the risk of COVID-19 at our workplaces. We continue to monitor the changing COVID-19 situation and respond accordingly in a timely manner. In October, we lifted our mandatory work from home measure, implemented in March, to open our modified workspaces in the Calgary offices to staff again, with workplace safety plans and protocols in place. However, due to rising COVID-19 cases in November this was scaled back and office staff are once again required to work from home. Mandatory work-from-home measures are now in place for all non-essential staff at our combined offices and worksites in Alberta, Saskatchewan and Manitoba until the end of March 2021, pending further review. Our U.S. and Atlantic Canada locations will continue to take direction from local health authorities regarding their COVID-19 workplace mandates. Staff levels at sites and offices have and will continue to follow guidance received from the applicable federal, provincial, state and local governments and public health officials.

YEAR IN REVIEW

During 2020, operating variables under Management's control performed well. We focused on delivering value through preserving financial resilience. Throughout the year, we demonstrated our ability to use our full suite of assets to maximize prices received for every barrel as we adjusted our Oil Sands production rates in response to price signals and stored volumes in a low-price environment and cleared inventory when we could obtain higher prices. We also remained focused on maintaining our low cost structure.

Operationally, our upstream assets performed well. Our upstream production averaged 471,740 BOE per day in 2020, compared with 451,680 BOE per day in 2019. In 2020 we managed our production to optimal levels, producing above the Government of Alberta's mandatory production curtailment as we purchased additional credits. As of December 2020, monthly oil production limits are no longer in effect and the Government of Alberta will give 30 to 60 days' notice if production limits are put back into place.

The Wood River and Borger refineries (the "Refineries") demonstrated reliable operational performance while operating below capacity for the majority of the year due to economic crude rate reductions in response to lower refined product demand and weak market crack spreads.

Throughout 2020, Management continued to focus on maintaining our low operating and capital cost structure.

Crude oil prices were volatile throughout the year due to demand and supply impacts as a result of COVID-19 and OPEC and non-OPEC members production level commitments. West Texas Intermediate ("WTI") benchmark crude oil prices ranged from a high of US$63.27 per barrel to a low of US$10.01 per barrel and averaged 31 percent lower than 2019. Western Canadian Select ("WCS") benchmark prices averaged US$26.80 per barrel, 39 percent lower than US$44.27 per barrel in 2019. Our average realized crude oil sales price of $28.82 per barrel decreased significantly compared with $53.95 per barrel in 2019 due to declining benchmark WTI prices.

As noted, COVID-19 had a significant impact on our results.

- Our first quarter results were impacted by measures taken to contain COVID-19 and the over-supply of crude oil. We responded by announcing reductions to our capital spending, operating and G&A costs, and temporarily suspended our dividend. Average WTI and WCS crude oil benchmark prices for the first quarter declined to US$46.17 per barrel and US$25.64 per barrel, respectively, which had a significant impact on our first quarter results with asset impairment charges of $318 million, a Net Loss of $1,797 million and our operating margin was negative $589 million;
- The second quarter was a transition period for the market. Crude oil prices were severely impacted, with WCS averaging a low of US$3.50 per barrel in April. This was followed by a steady strengthening of crude oil prices with WCS averaging US$33.97 per barrel in June, caused by the easing of some of the restrictions imposed by governments to limit the spread of COVID-19 combined with the commitment by OPEC and non-OPEC members to reduce crude oil production levels in response to lower demand and low commodity prices. We responded to price signals, managing our Oil Sands production by reducing production rates in April and successfully ramped up production in May and June, to achieve peak production rates, when pricing was more favourable. Our Net Loss of $235 million improved in the second quarter compared with the first quarter and our operating margin was $291 million, demonstrating some momentum in economic recovery;
- Our results in the third quarter gradually improved along with the improvement in crude oil prices. WTI and WCS averaged US$40.93 per barrel and US$31.84 per barrel, respectively, in the third quarter. However, crude oil prices remained low as the second wave of COVID-19 infections drove uncertainty. Operationally, our upstream assets continued to perform well and in response to increasing crude oil prices, we purchased production curtailment credits available in the market to produce above our curtailment limit and sold crude oil inventory that had built up when crude oil prices were lower. Our Net Loss of $194 million, which included impairments and write-downs of $521 million, continued to improve quarter over quarter and operating margin of $594 million more than doubled that of the second quarter of 2020. In the third quarter we used the proceeds from the issuance of US$1.0 billion in 5.375 percent senior unsecured notes due in 2025 to repay short-term borrowings; and
- Our fourth quarter results were mixed as COVID-19 infection rates, global economic performance and speculation on vaccine development impacted the pace of crude oil demand recovery with WTI and WCS averaging US$42.66 per barrel and US$33.36 per barrel, respectively. Our fourth quarter Net Loss of $153 million decreased and operating margin of $625 million increased compared with the third quarter of

2020, and we recognized $298 million in impairments and write-downs. Net income also included a $100 million loss related to the Keystone XL pipeline project. We exited the year with Net Debt of $7.2 billion.

In 2020, upstream operating margin of $1,309 million decreased compared with $3,723 million in 2019, due to a lower average realized crude oil sales price, the use of higher priced condensate in a declining market earlier in the year, partially offset by lower royalties and higher sales volumes.

Our Refining and Marketing segment generated operating margin of negative $388 million, down from $737 million in 2019 primarily due to decreased market crack spreads, lower crude advantage and reduced crude oil runs, partially offset by lower operating costs.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results

	2020	Percent Change	2019	Percent Change	2018
Upstream Production Volumes					
Oil Sands (barrels per day)					
Foster Creek	**163,210**	**2**	159,598	(1)	161,979
Christina Lake	**218,513**	**12**	194,659	(3)	201,017
Total Oil Sands Crude Oil	**381,723**	**8**	354,257	(2)	362,996
Conventional (1) (BOE per day)	**89,932**	**(8)**	97,423	(19)	120,258
Total Production from Continuing Operations (BOE per day)	**471,740**	**4**	451,680	(7)	483,458
Production From Discontinued Operations (BOE per day)	**-**	**-**	-	(100)	294
Sales from Continuing Operations (2) (BOE per day)	**420,456**	**8**	390,813	(10)	436,163
Oil and Gas Reserves (MMBOE)					
Proved	**5,030**	**(1)**	5,103	(1)	5,167
Probable	**1,656**	**(6)**	1,768	(3)	1,821
Proved plus Probable	**6,686**	**(3)**	6,871	(2)	6,988
Refining and Marketing					
Crude Oil Runs (3) (Mbbls/d)	**372**	**(16)**	443	(1)	446
Refined Product (3) (Mbbls/d)	**385**	**(17)**	466	(1)	470
Crude Utilization (3) (percent)	**75**	**(17)**	92	(5)	97
Crude-by-Rail (barrels per day)					
Crude-by-Rail Loads (4)	**30,422**	**(43)**	53,345	1,197	4,113
Crude-by-Rail Sales (5)	**33,870**	**(30)**	48,626	1,367	3,314

(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 2020 reflects production above our curtailment limit as we managed to optimal production levels by purchasing production curtailment credits. In 2019, our production was in line with the Government of Alberta's mandatory production curtailment program and impacted by a planned turnaround at Christina Lake during the second quarter of 2019.

Conventional production in 2020 decreased to 89,932 BOE per day compared with 97,423 BOE per day in 2019, due to natural declines, partially offset by Marten Hills heavy oil production prior to its disposition, as well as fewer shut-ins for low commodity pricing. Prior to the disposition, Marten Hills production averaged approximately 2,800 barrels per day.

Oil and Gas Reserves

Based on our reserves reports prepared by independent qualified reserves evaluators ("IQREs"), at the end of 2020 we had total proved reserves and total proved plus probable reserves of approximately 5.0 billion BOE and 6.7 billion BOE, respectively, decreases of one percent and three percent compared with 2019. As a result of the close of the Arrangement on January 1, 2021, including reported reserves from Husky, our total proved reserves and total proved plus probable reserves are anticipated to increase by approximately 1.2 billion BOE and 1.8 billion BOE, respectively.

Additional information about our reserves is included in the Oil and Gas Reserves section of this MD&A.

Refining and Marketing

Crude oil runs and refined product output decreased in 2020 as both Refineries implemented crude rate reductions in response to reduced demand as a result of COVID-19. The economic crude rate reductions in 2020 had a greater impact than the operational performance impacts from unplanned outages, planned maintenance and turnaround activities at the Refineries 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

Market factors such as falling crude oil prices, 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)	**2020**	**Percent Change**	2019	Percent Change	2018 (1)
Operating Margin (2) (3)	**921**	**(79)**	4,460	86	2,394
Cash From (Used in) Operating Activities					
From Continuing Operations	**273**	**(92)**	3,285	55	2,118
Total	**273**	**(92)**	3,285	53	2,154
Adjusted Funds Flow (4)	**147**	**(96)**	3,702	115	1,721
Operating Earnings (loss) (2) (4)	**(2,604)**	**(671)**	456	117	(2,755)
Per Share ($) (5)	**(2.12)**	**(673)**	0.37	117	(2.24)
Net Earnings (Loss)					
From Continuing Operations	**(2,379)**	**(208)**	2,194	175	(2,916)
Per Share ($) (5)	**(1.94)**	**(209)**	1.78	175	(2.37)
Total	**(2,379)**	**(208)**	2,194	182	(2,669)
Per Share ($) (5)	**(1.94)**	**(209)**	1.78	182	(2.17)
Total Assets	**32,770**	**(7)**	35,173	-	35,174
Total Long-Term Financial Liabilities (6)	**9,041**	**7**	8,483	(1)	8,602
Capital Investment (7)	**841**	**(28)**	1,176	(14)	1,363
Dividends					
Cash Dividends	**77**	**(70)**	260	6	245
Per Share ($)	**0.0625**	**(71)**	0.2125	6	0.2000

(1) On January 1, 2019, we adopted IFRS 16, "Leases" ("IFRS 16"), 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 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 Long-Term Debt, Lease Liabilities, Contingent Payment Liabilities and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.
(7) Includes expenditures on property, plant and equipment ("PP&E") and Exploration and Evaluation ("E&E") assets.

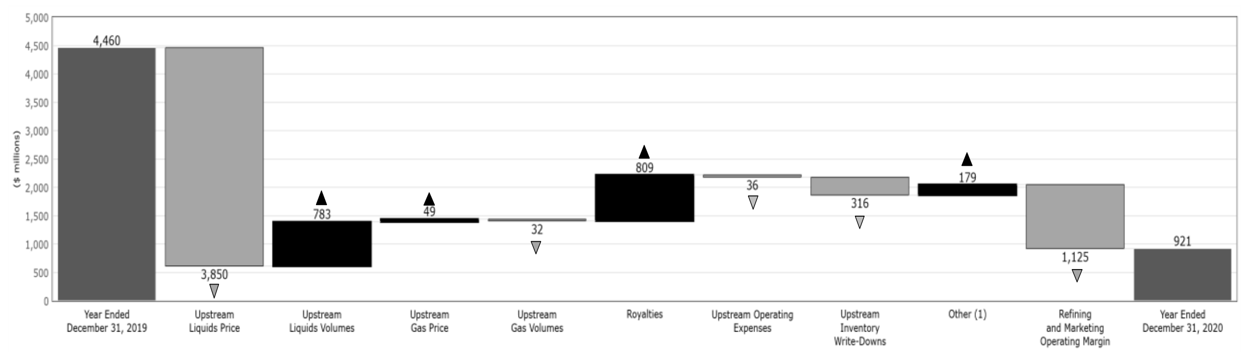
Operating Margin

Operating Margin is an additional subtotal found in Note 1 of the Consolidated Financial Statements and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Margin is defined as revenues less purchased product, transportation and blending, operating expenses, 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.

($ millions)	2020	2019 (1) (2)	2018 (2)
Gross Sales	**14,200**	22,042	22,113
Less: Royalties	**364**	1,173	546
Revenues	**13,836**	20,869	21,567
Expenses			
Purchased Product	**5,397**	8,795	9,201
Transportation and Blending	**4,480**	5,234	5,969
Operating Expenses	**2,236**	2,324	2,367
Inventory Write-Down (Reversal)	**555**	49	60
Realized (Gain) Loss on Risk Management Activities	**247**	7	1,576
Operating Margin	**921**	4,460	2,394

(1) The comparative period has been reclassified to conform with the current period treatment of non-cash inventory write-downs and reversals.
(2) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

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 primarily due to:

- A 47 percent decline in our average crude oil sales price resulting from lower WTI and WCS benchmark pricing;
- Lower Operating Margin from our Refining and Marketing segment primarily due to reduced market crack spreads, lower crude advantage and reduced crude oil runs, partially offset by lower operating costs; and
- The use of higher priced condensate in a declining market earlier in the year.

These decreases in Operating Margin were partially offset by:

- Lower royalties due to lower realized prices;
- Higher liquids sales volumes; 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.

($ millions)	2020	2019	2018 (1)
Cash From (Used in) Operating Activities	**273**	3,285	2,154
(Add) Deduct:			
Net Change in Other Assets and Liabilities	**(72)**	(84)	(72)
Net Change in Non-Cash Working Capital (2)	**198**	(333)	505
Adjusted Funds Flow (2)	**147**	3,702	1,721

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.
(2) 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 significantly in 2020, primarily due to lower Operating Margin, as discussed above, transaction costs of $29 million related to the Arrangement, and higher finance costs. The decrease was partially offset by funding from the CEWS program and a current tax recovery of $13 million compared with current tax expense of $17 million. Adjusted Funds Flow was further reduced by a $100 million loss related to the Keystone XL pipeline project. The change in non-cash working capital in 2020 was primarily due to a decrease in inventory and accounts receivable, partially offset by a decrease in accounts payable.

In 2019, the change in non-cash working capital was primarily due to an increase in accounts receivable and inventory, partially offset by an increase in accounts payable and a decrease in income tax receivable.

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)	2020	2019	2018 (1)
Earnings (Loss), Before Income Tax	**(3,230)**	1,397	(3,926)
Add (Deduct):			
Unrealized Risk Management (Gain) Loss (2)	**56**	149	(1,249)
Non-Operating Unrealized Foreign Exchange (Gain) Loss (3)	**(194)**	(787)	593
(Gain) Loss on Divestiture of Assets	**(81)**	(2)	795
Operating Earnings (Loss), Before Income Tax	**(3,449)**	757	(3,787)
Income Tax Expense (Recovery)	**(845)**	301	(1,032)
Total Operating Earnings (Loss)	**(2,604)**	456	(2,755)

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.
(2) Includes the reversal of unrealized (gains) losses recorded in prior periods.
(3) 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.

We incurred an Operating Loss in 2020, relative to Operating Earnings in 2019, primarily due to lower Cash From Operating Activities and Adjusted Funds Flow, as discussed above, higher Depletion, Depreciation and Amortization ("DD&A") including impairment charges of $1,112 million, and operating unrealized foreign exchange losses of $63 million compared with gains of $27 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 $401 million in 2019 on our unsecured notes, a re-measurement gain of $80 million on the contingent payment compared with a loss of $164 million in 2019, and lower non-cash employee long-term incentive costs.

Net Earnings (Loss)

($ millions)	2020 vs. 2019	2019 vs. 2018 (1)
Net Earnings (Loss), Comparative Year	**2,194**	**(2,916)**
Increase (Decrease) due to:		
Operating Margin	**(3,539)**	**2,066**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**93**	**(1,398)**
Unrealized Foreign Exchange Gain (Loss)	**(696)**	**1,476**
Re-measurement of Contingent Payment	**244**	**(114)**
Gain (Loss) on Divestiture of Assets	**79**	**797**
Expenses (2)	**416**	**573**
DD&A	**(1,215)**	**(118)**
Exploration Expense	**(9)**	**2,041**
Income Tax Recovery (Expense)	**54**	**(213)**
Net Earnings (Loss), End of Year	**(2,379)**	**2,194**

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.
(2) Includes Corporate and Eliminations realized risk management (gains) losses, general and administrative, 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.

Net Loss of $2,379 million was significantly lower than Net Earnings of $2,194 million in 2019 due to lower Operating Earnings, as discussed above, and non-operating unrealized foreign exchange gains of $194 million compared with $787 million in 2019 partially offset by unrealized risk management losses of $56 million in 2020 compared with losses of $149 million in 2019 and a gain of $79 million on the divestiture of the Marten Hills assets.

Capital Investment

($ millions)	2020	2019 (1)	2018 (2)
Oil Sands	**427**	656	870
Conventional (3)	**78**	103	228
Refining and Marketing	**276**	280	208
Corporate and Eliminations	**60**	137	57
Capital Investment (4)	**841**	1,176	1,363

(1) In the first quarter of 2020, Marten Hills was reclassified from the Oil Sands segment to the Conventional segment, prior to the divestiture in December 2020. The comparative information has been reclassified.
(2) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.
(3) This segment was previously referred to as the Deep Basin segment.
(4) Includes expenditures on PP&E and E&E assets.

Capital investment in 2020 decreased compared with 2019, reflecting our reduced capital investment program and revised budget announced in April. Our upstream capital investment focused primarily on sustaining programs. Our downstream capital expenditures focused primarily on yield enhancement, reliability and maintenance projects, as well as storage infrastructure projects.

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

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates (1)

(US$/bbl, unless otherwise indicated)	**Q4 2020**	Q4 2019	**2020**	**Percent Change**	2019	2018
Brent						
Average	**45.24**	62.50	**43.21**	**(33)**	64.18	71.53
WTI						
Average	**42.66**	56.96	**39.40**	**(31)**	57.03	64.77
Average Differential Brent-WTI	**2.58**	5.54	**3.81**	**(47)**	7.15	6.76
WCS at Hardisty ("WCS")						
Average	**33.36**	41.13	**26.80**	**(39)**	44.27	38.46
Average Differential WTI-WCS	**9.30**	15.83	**12.60**	**(1)**	12.76	26.31
Average (C$/bbl)	**43.41**	54.29	**35.59**	**(39)**	58.77	49.81
WCS at Nederland						
Average	**40.36**	51.47	**35.86**	**(35)**	55.56	62.05
Average Differential WTI-WCS at Nederland	**2.30**	5.49	**3.54**	**141**	1.47	2.72
West Texas Sour ("WTS")						
Average	**43.02**	57.26	**39.37**	**(30)**	56.27	57.24
Average Differential WTI-WTS	**(0.36)**	(0.30)	**0.03**	**(96)**	0.76	7.53
Condensate (C5 @ Edmonton)						
Average	**42.54**	53.01	**37.16**	**(30)**	52.86	61.00
Average Differential WTI-Condensate (Premium)/Discount	**0.12**	3.95	**2.24**	**(46)**	4.17	3.77
Average Differential WCS-Condensate (Premium)/Discount	**(9.18)**	(11.88)	**(10.36)**	**21**	(8.59)	(22.54)
Average (C$/bbl)	**55.36**	69.97	**49.44**	**(30)**	70.15	79.02
Average Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**47.31**	64.83	**45.24**	**(36)**	70.55	77.96
Chicago Ultra-low Sulphur Diesel ("ULSD")	**54.21**	78.09	**50.08**	**(36)**	77.97	86.75
Refining Margin: Average 3-2-1 Crack Spreads (2)						
Chicago	**7.05**	12.27	**7.54**	**(53)**	16.00	15.97
Group 3	**7.57**	14.60	**8.67**	**(48)**	16.67	16.74
Average Natural Gas Prices						
AECO (3) (C$/Mcf)	**2.77**	2.34	**2.24**	**38**	1.62	1.53
NYMEX (US$/Mcf)	**2.66**	2.50	**2.08**	**(21)**	2.63	3.09
Foreign Exchange Rate (US$ per C$1)						
Average	**0.768**	0.758	**0.746**	**(1)**	0.754	0.772
End of Period	**0.785**	0.770	**0.785**	**2**	0.770	0.733

(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.

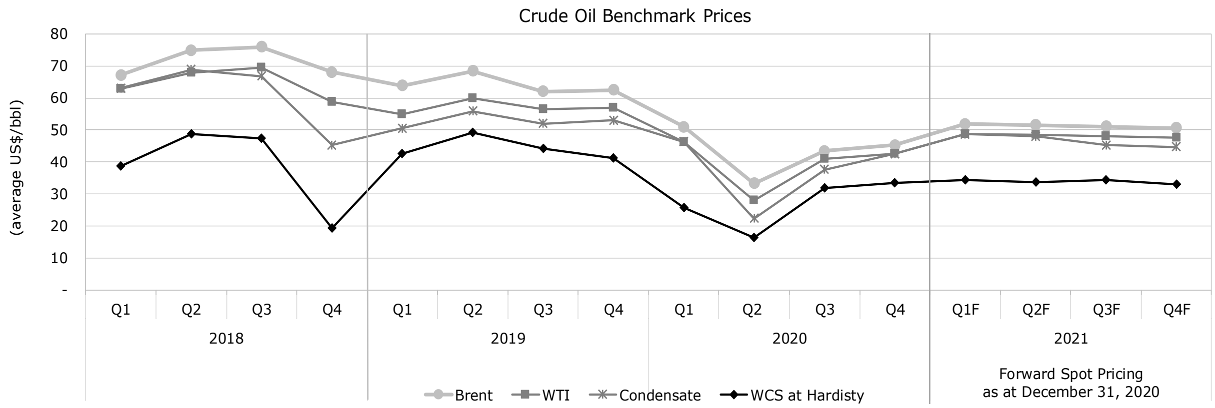
Crude Oil and Condensate Benchmarks

In 2020, the demand for crude oil was under pressure due to COVID-19 while OPEC-led production cuts reduced the impact of the demand destruction resulting in lower average Brent and WTI crude oil benchmark prices.

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 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 2020, the WTI-WCS at Hardisty differential narrowed slightly compared with 2019 as reduced Western Canadian Sedimentary Basin ("WCSB") crude supply resulted in excess pipeline capacity for parts of the year, reducing the need for more expensive crude-by-rail shipments. This resulted in average differentials being similar to 2019 when the Government of Alberta enforced their mandatory production curtailment limits.

WCS at Nederland is a heavy oil benchmark at the U.S. Gulf Coast ("USGC") which is representative of pricing for our sales in the USGC. WCS at Nederland crude oil prices weakened in 2020, consistent with falling crude oil prices globally as refiners lowered crude runs to adjust to reduced demand for products. In 2020, WCS at Nederland benchmark prices relative to WTI widened compared with 2019. The widening was mainly attributed to very wide differentials in the second quarter of 2020 when demand was weak and OPEC+ had not yet committed to production cuts. OPEC+ production cuts are weighed towards medium and heavy sour grades and have resulted in narrower heavy differentials at the USGC in the second half of 2020 compared with the same period of 2019.



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 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 wider differential generally results in a decrease 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.

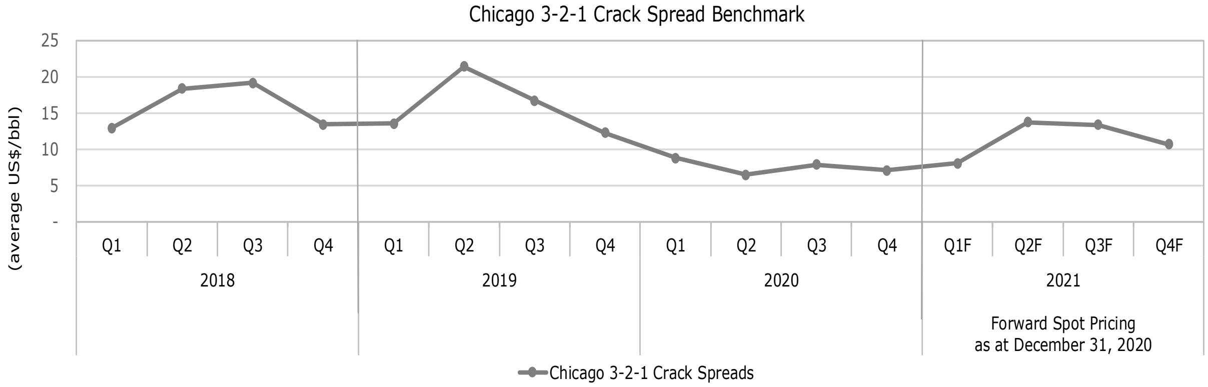
Average condensate benchmark prices were at a narrower discount relative to WTI in Alberta in 2020 as a result of weaker diluent demand due to shut-in heavy oil production offset by lower imported barrels from the U.S. and strong global demand.

Refining Benchmarks

The Chicago Regular Unleaded Gasoline ("RUL") and Chicago Ultra-low Sulphur Diesel ("ULSD") benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 market crack spread. The 3-2-1 market crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI-based crude oil feedstock prices and valued on a last in, first out accounting basis.

Average Chicago refined product prices decreased in 2020, 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 in 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 liquified 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 $140 million on our revenues in 2020. The strengthening of the Canadian dollar relative to the U.S. dollar as at December 31, 2020 compared with December 31, 2019, resulted in unrealized foreign exchange gains of $194 million on the translation of our U.S. dollar debt.

REPORTABLE SEGMENTS

Our reportable segments at December 31, 2020 are:

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 2020 and our new resource play, Marten Hills, was reclassified from the Oil Sands segment to the Conventional segment. Comparative periods have been reclassified. On December 2, 2020, we completed the sale of our Marten Hills assets with a retained Gross Overriding Royalty agreement.

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)	2020	2019	2018
Oil Sands	**7,190**	9,695	9,553
Conventional [1]	**595**	661	831
Refining and Marketing	**6,051**	10,513	11,183
Corporate and Eliminations	**(609)**	(689)	(724)
	13,227	20,180	20,843

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

Oil Sands revenues decreased due to lower average realized liquids sales prices, partially offset by lower royalties and higher sales volumes.

Conventional revenues decreased 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 heavy oil production from our Marten Hills assets prior to its divestiture.

Refining and Marketing revenues declined in 2020. 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 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.

Overall, revenues declined slightly in 2019 compared with 2018, primarily due to lower refined product pricing and lower upstream sales volumes, partially offset by higher realized crude oil pricing.

OIL SANDS

In 2020, we:

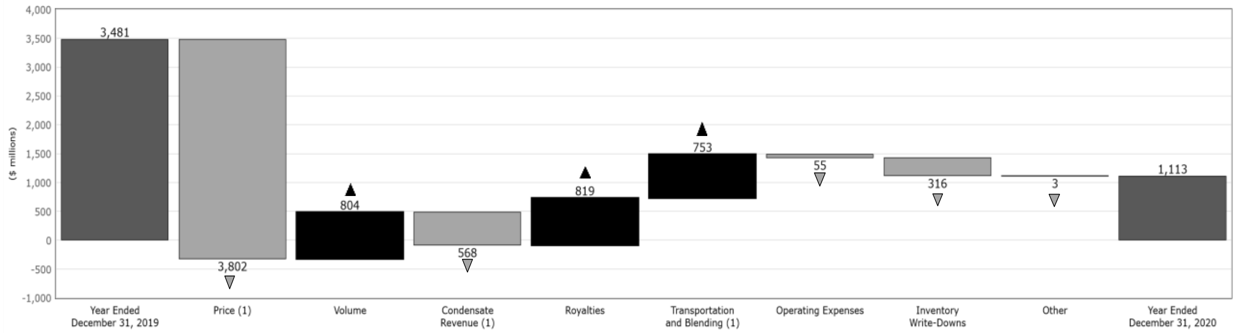
- Delivered safe and reliable operations;
- Increased our Oil Sands production rates to average 381,723 barrels per day;
- Demonstrated our ability to use our full suite of assets to maximize prices received for every barrel as we managed to store volumes in a low-price environment and cleared inventory when we could obtain higher prices; and
- Generated Operating Margin of $1,113 million, a decrease of $2,368 million compared with 2019 due to lower average realized sales prices, partially offset by lower royalties, higher volumes and lower transportation and blending costs.

Financial Results

($ millions)	2020	2019	2018 [1]
Gross Sales	**7,514**	10,838	10,026
Less: Royalties	**324**	1,143	473
Revenues	**7,190**	9,695	9,553
Expenses			
Transportation and Blending	**4,399**	5,152	5,879
Operating	**1,094**	1,039	1,037
Inventory Write-Down (Reversal)	**316**	-	-
(Gain) Loss on Risk Management	**268**	23	1,551
Operating Margin	**1,113**	3,481	1,086
Depreciation, Depletion and Amortization	**1,684**	1,543	1,439
Exploration Expense	**9**	18	6
Segment Income (Loss)	**(580)**	1,920	(359)

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

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 2020, our realized crude oil sales price was $28.64 per barrel compared with $53.78 per barrel in 2019, consistent with the overall declines in crude oil benchmark pricing led by a decrease in WTI average benchmark price, partially offset by the lower cost of condensate with an average price of US$37.16 per barrel (2019 – US$52.86 per barrel). The decrease in our crude oil price also reflects the wider WCS-Condensate premium of US$10.36 per barrel (2019 – premium of US$8.59 per barrel). In 2020, COVID-19 impacts resulted in low WTI-WCS differentials during periods of the year resulting in more volumes sold in Alberta compared with 2019, which decreased our realized sales prices. In 2019, we sold more than 25 percent of our production at sales locations outside of Alberta. We used our transportation, storage and logistics assets and expertise to sell our products in higher-priced months, when the opportunities were available, which reduced the impact of the drop in crude oil prices on our realized sales prices.

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Our realized crude oil sales price is influenced by the cost of condensate used in blending. Our blending ratios range between 25 percent and 33 percent. As the cost of condensate 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 year we reduced condensate volumes transported from the USGC, as the price differential between market hubs was not significant enough to cover variable transportation costs for part of the year. Condensate prices declined during the summer months due to lower demand making it more cost-effective to buy in Alberta compared with the USGC.

As a result of our decisions to store rather than sell, we were able to minimize the impact on our realized sales prices. 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 additional revenues generated from the underlying physical sales may be impacted 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.

Production Volumes

(barrels per day)	**2020**	**Percent Change**	2019	Percent Change	2018
Foster Creek	**163,210**	**2**	159,598	(1)	161,979
Christina Lake	**218,513**	**12**	194,659	(3)	201,017
	381,723	**8**	354,257	(2)	362,996

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 2019, our production was in line with Government of Alberta's mandatory production curtailment program.

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)	**2020**	2019	2018
Foster Creek	**7.9**	18.8	18.0
Christina Lake	**14.4**	21.6	4.8

In 2020, royalties decreased $819 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 related to decreased annual average WTI benchmark pricing.

Expenses

Transportation and Blending

Total transportation and blending costs have decreased $753 million compared with 2019. Blending costs decreased due to a decline in condensate price, partially offset by increased condensate volumes required to move increased bitumen volumes.

Transportation costs increased primarily due to higher fixed costs in 2020, as our rail freight and offloading commitments gradually increased in 2019 as the crude-by-rail program ramped up.

Per-unit Transportation Expenses

Foster Creek per-barrel transportation costs decreased $0.65 per barrel due to lower pipeline tariffs as a result of lower sales at U.S. destinations and increased sales volumes, partially offset by increased rail transportation costs from higher fixed costs in 2020, as discussed above. Christina Lake per-barrel transportation costs increased $0.31 per barrel as a result of increased pipelines tariff rates due to higher piped sales at U.S. destinations, higher fixed costs, as discussed above, and higher storage costs, partially offset by increased sales volumes relative to 2019.

Operating

Total operating costs increased $55 million due to higher fuel, workforce, and chemical costs from increased production, partially offset by lower repairs and maintenance costs and fluid, waste handling and trucking costs from the 2020 planned turnaround compared with the planned turnaround at Christina Lake in the second quarter of 2019 and reduction in activity and resources due to COVID-19 safety measures.

Per-unit Operating Expenses

($/bbl)	**2020**	**Percent Change**	2019	Percent Change	2018 (1)
Foster Creek					
Fuel	**2.83**	**15**	2.47	16	2.13
Non-fuel	**6.41**	**(4)**	6.67	(2)	6.84
Total	**9.24**	**1**	9.14	2	8.97
Christina Lake					
Fuel	**2.18**	**6**	2.06	10	1.87
Non-fuel	**4.61**	**(13)**	5.27	11	4.73
Total	**6.79**	**(7)**	7.33	11	6.60
Total	**7.84**	**(4)**	8.15	7	7.65

(1) *On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.*

At both Foster Creek and Christina Lake, per-barrel fuel costs increased due to higher natural gas prices and consumption, 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 for the 2020 planned turnaround compared with costs for the planned turnaround in 2019, partially offset by higher workforce and chemical costs.

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 and operating expenses 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		
($/bbl)	**2020 (2)**	2019	2018	**2020 (2)**	2019	2018
Sales Price	**30.80**	57.21	42.63	**27.04**	50.91	33.42
Royalties	**1.57**	8.44	6.25	**2.90**	9.42	1.37
Transportation and Blending	**11.05**	11.70	8.34	**6.95**	6.64	5.25
Operating Expenses	**9.24**	9.14	8.97	**6.79**	7.33	6.60
Netback Excluding Realized Risk Management	**8.94**	27.93	19.07	**10.40**	27.52	20.20
Realized Risk Management Gain (Loss)	**(1.83)**	(0.16)	(11.49)	**(1.93)**	(0.19)	(11.66)
Netback Including Realized Risk Management	**7.11**	27.77	7.58	**8.47**	27.33	8.54

(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, partially offset by lower royalties, operating costs and transportation and blending 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 $0.30 per barrel.

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 2020, DD&A increased $141 million compared with 2019, due to higher sales volumes, partially offset by a decrease in our average depletion rates. Our depletion rate decreased due to lower future development costs and a decrease in maintenance capital. The average depletion rate for the year ended December 31, 2020 was approximately $10.40 per barrel (2019 – $11.15 per barrel).

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

Capital Investment

($ millions)	**2020**	2019	2018 (1)
Foster Creek	**193**	243	379
Christina Lake	**162**	362	445
	355	605	824
Other (2)	**72**	51	46
Capital Investment (3)	**427**	656	870

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.
(2) Includes Narrows Lake and new resource plays. In Q1 2020, Marten Hills was reclassified from the Oil Sands segment to the Conventional segment. The comparative information has been reclassified.
(3) 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)		
	2020	2019	2018	**2020**	2019	2018
Foster Creek	**38**	14	43	**-**	-	14
Christina Lake	**42**	18	63	**-**	11	38
	80	32	106	**-**	11	52
Other (2)	**75**	26	20	**-**	-	-
	155	58	126	**-**	11	52

(1) Steam-assisted gravity drainage ("SAGD") well pairs are counted as a single producing well.
(2) Includes Narrows Lake and new resource plays. In Q1 2020, Marten Hills was reclassified from the Oil Sands segment to the Conventional segment. The comparative information has been reclassified.

Stratigraphic test wells were drilled to help identify well pad locations for sustaining wells and future expansion phases, and to further progress the evaluation of emerging assets. In 2020, we increased the number of gross stratigraphic test wells drilled by increasing the scope of the program and incorporating more multi-leg wells, which have a reduced surface impact.

CONVENTIONAL

In 2020, we:

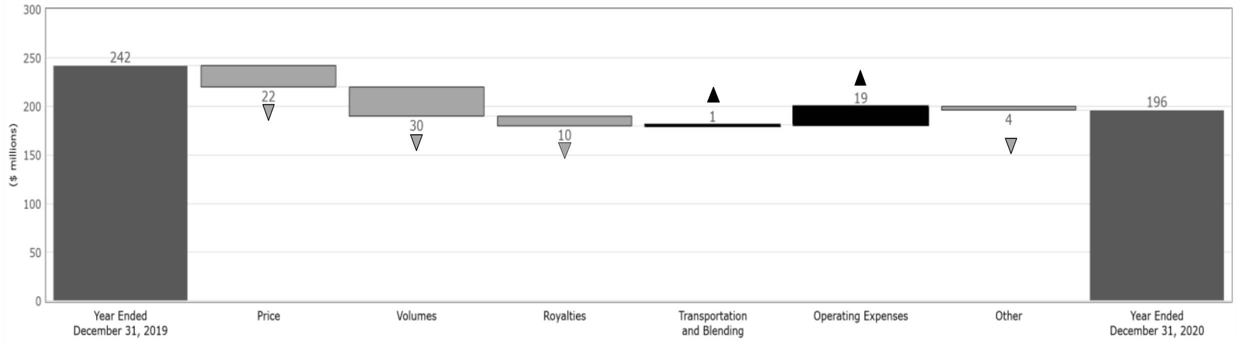
- Produced a total of 89,932 BOE per day, down from 2019 due to natural declines partially offset by added production from the Marten Hills area, prior to its divestiture on December 2, 2020;
- Generated Operating Margin of $196 million, a decrease from 2019 due to reduced sales volumes, lower realized prices, and higher royalties, partially offset by lower operating costs;
- Reduced operating costs by approximately six percent to $318 million compared with $337 million in 2019, by optimizing operations, focusing on critical repairs and maintenance activities and leveraging our infrastructure;
- Earned a Netback of $5.16 per BOE; and
- Divested our Marten Hills assets and entered into a Gross Overriding Royalty agreement and an equity position in the purchaser to benefit from its future development.

Financial Results

($ millions)	**2020**	2019	2018 (1)
Gross Sales	**635**	691	904
Less: Royalties	**40**	30	73
Revenues	**595**	661	831
Expenses			
Transportation and Blending	**81**	82	90
Operating	**318**	337	403
(Gain) Loss on Risk Management	**-**	-	26
Operating Margin	**196**	242	312
Depreciation, Depletion and Amortization	**880**	319	412
Exploration Expense	**82**	64	2,117
Segment Income (Loss)	**(766)**	(141)	(2,217)

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

Operating Margin Variance



Revenues

Price

	2020	2019	2018
Heavy Oil ($/bbl)	**31.45**	-	-
Light and Medium Oil ($/bbl)	**42.78**	65.70	66.71
NGLs ($/bbl)	**22.04**	26.36	38.56
Natural Gas ($/mcf)	**2.37**	2.01	1.72
Total Oil Equivalent ($/BOE)	**17.84**	17.95	19.31

For the year ended December 31, 2020, revenues declined due to decreased average realized liquids sales prices and lower natural gas sales volumes, partially offset by higher natural gas sales prices and liquids sales volumes. In 2020, prior to its divestiture, we had heavy oil production from Marten Hills of approximately 2,700 barrels per day. In 2020, revenues included $49 million of processing fee revenue related to our interests in natural gas processing facilities (2019 – $53 million). We do not include processing fee revenue in our per-unit pricing metrics or our Netbacks.

Production Volumes

	2020	2019	2018
Liquids			
Crude Oil (barrels per day)	**7,244**	4,911	5,916
NGLs (barrels per day)	**19,513**	21,762	26,538
	26,757	26,673	32,454
Natural Gas (MMcf per day)	**379**	424	527
Total Production (BOE/d)	**89,932**	97,423	120,258
Natural Gas Production (percentage of total)	**70**	73	73
Liquids Production (percentage of total)	**30**	27	27

Production in 2020 decreased due to natural declines, partially offset by Marten Hills heavy oil production, prior to its divestiture.

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 direct 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 sales pipelines.

In 2020, our effective royalty rate was 7.9 percent (2019 – 5.1 percent). The higher royalty rate is due to a reduction in capital and operating expenses in 2019 resulting in a reduced GCA recovery.

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. Per-unit transportation costs averaged $2.46 per BOE (2019 – $2.31 per BOE), due to lower sales volumes and increased pipeline costs.

Operating

Total operating costs decreased to $318 million (2019 – $337 million) through continuing efforts to optimize our operations and workforce, focusing on critical repair and maintenance activities and leveraging our infrastructure to lower the cost structure.

Per-unit operating costs increased to an average of $8.99 per BOE (2019 – $8.79 per BOE) primarily due to lower sales volumes partially offset by lower workforce costs, decreased property tax and lease costs primarily for lower lease rentals and from regulatory cost relief, and lower repairs and maintenance as a result of lower activity and deferrals.

Netbacks

($/BOE)	**2020**	2019	2018 [1]
Sales Price	**17.84**	17.95	19.31
Royalties	**1.23**	0.83	1.67
Transportation and Blending	**2.46**	2.31	1.97
Operating Expenses	**8.99**	8.79	8.58
Netback Excluding Realized Risk Management	**5.16**	6.02	7.09
Realized Risk Management Gain (Loss)	**(0.01)**	(0.01)	(0.59)
Netback Including Realized Risk Management	**5.15**	6.01	6.50

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

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 $9.85 per BOE for the year ended December 31, 2020 (2019 – $9.15 per BOE).

For the year ended December 31, 2020, total Conventional DD&A was $880 million (2019 – $319 million). The increase was due to impairment charges of $555 million, as a result of the decline in forward crude oil and natural gas prices and a change in our future development plans, and higher DD&A rates.

Exploration expense of $82 million was recorded for the year ended December 31, 2020 (2019 – $64 million) as the carrying value of certain E&E assets were not considered to be recoverable.

Divestiture

On December 2, 2020, we sold our Marten Hills assets in northern Alberta to Headwater Exploration Inc. ("Headwater") for total consideration of $138 million, excluding the retained gross overriding royalty interest ("GORR"). A before-tax gain of $79 million was recorded on the sale (after-tax – $65 million). Total consideration received consists of $33 million cash, 50 million common shares valued at $97 million and 15 million share purchase warrants valued at $8 million at the date of close. The share purchase warrants have a three-year term and an exercise price of $2.00 per share. We retained a GORR in the Marten Hills assets which was reclassified from E&E to PP&E for $41 million at the date of close. The investment in Headwater is held in other assets.

Capital Investment

In 2020, we invested $78 million compared with $103 million in 2019. Capital investment 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 a drilling program targeting low-risk, high-return development.

($ millions)	**2020**	2019 [1]	2018 [1]
Seismic	**5**	-	-
Drilling and Completions	**27**	32	123
Facilities	**20**	34	58
Other	**26**	37	47
Capital Investment [2]	**78**	103	228

(1) In Q1 2020, 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 2020 there were six net wells drilled, one net well completed and three net wells were tied-in and brought on production. In 2019, there were 11 net wells drilled, two net wells completed and three net wells tied-in.

REFINING AND MARKETING

In 2020, we:

- Managed to economic crude oil runs of 372,000 barrels per day, lower than 2019 in response to the economic slowdown due to COVID-19;
- Reported Operating Margin of negative $388 million, a decrease of $1,125 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;
- Recorded an impairment charge of $450 million, as additional DD&A expense, associated with the Borger cash-generating unit ("CGU"); and
- Completed the temporary ramp down of our crude-by-rail program in the second quarter until pricing fundamentals supported its continuation in the fourth quarter.

Financial Results

($ millions)	**2020**	2019 [1]	2018 [1] [2]
Revenues	**6,051**	10,513	11,183
Purchased Product	**5,397**	8,795	9,201
Inventory Write-Down (Reversal)	**239**	49	60
Gross Margin	**415**	1,669	1,922
Expenses			
Operating	**824**	948	927
(Gain) Loss on Risk Management	**(21)**	(16)	(1)
Operating Margin	**(388)**	737	996
Depreciation, Depletion and Amortization	**739**	280	222
Segment Income (Loss)	**(1,127)**	457	774

(1) The comparative period has been reclassified to conform with current period treatment of non-cash inventory write-downs and reversals.
(2) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

Refinery Operations [1]

	2020	2019	2018
Crude Oil Capacity (Mbbls/d)	**495**	482	460
Crude Oil Runs (Mbbls/d)	**372**	443	446
Heavy Crude Oil	**149**	177	191
Light/Medium	**223**	266	255
Refined Products (Mbbls/d)	**385**	466	470
Gasoline	**195**	223	233
Distillate	**127**	167	156
Other	**63**	76	81
Crude Utilization (percent)	**75**	92	97

(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. 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 Christina Dilbit Blend, 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 2020 compared with 2019 as both Refineries implemented crude rate reductions in response to the reduced demand due to COVID-19. In 2019, operational performance was impacted by unplanned outages, planned maintenance and turnaround activities at both Refineries.

Crude-By-Rail Terminal

Our crude-by-rail program was suspended in the first quarter in response to the low price market environment. The suspension was completed during the second quarter and lifted in the fourth quarter as market conditions improved. In 2020, we loaded an average of 32,213 barrels per day (22,891 barrels per day of our volumes) from our Bruderheim crude-by-rail terminal compared with an average of 65,293 barrels per day (45,324 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 2020, Refining and Marketing gross margin decreased $1,254 million resulting from decreased market crack spreads and crude advantage due to lower global crude oil and refined product pricing, and reduced crude oil runs.

In the year ended December 31, 2020, the cost of Renewable Identification Numbers ("RINs") was $177 million (2019 – $99 million). RIN costs increased, primarily due to higher pricing, partially offset by lower volume obligations. In 2020, RINs prices have been volatile and have steadily increased as RIN generation declined year over year, and at the same time RIN demand increased following a federal court decision to reduce the number of small refiners eligible for hardship exemptions.

Operating Expense

Primary drivers of operating expenses in 2020 were labour, maintenance, and utilities. Operating expenses decreased primarily due to lower maintenance activity compared with 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 $739 million compared with $280 million in 2019. The increase in DD&A is primarily due to an impairment charge of $450 million related to the Borger CGU.

Capital Investment

($ millions)	**2020**	2019	2018 (1)
Wood River Refinery	**158**	128	119
Borger Refinery	**85**	100	85
Marketing	**33**	52	4
Capital Investment	**276**	280	208

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

Capital expenditures in 2020 focused primarily on yield enhancement, reliability and maintenance projects, as well as storage infrastructure projects.

CORPORATE AND ELIMINATIONS

In 2020, our risk management activities resulted in:

- Unrealized risk management losses of $56 million (2019 – $149 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 $5 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)	**2020**	2019	2018 (1)
General and Administrative (2)	**292**	331	1,020
Finance Costs	**536**	511	627
Interest Income	**(9)**	(12)	(19)
Foreign Exchange (Gain) Loss, Net	**(181)**	(404)	854
Transaction Costs	**29**	-	-
Re-measurement of Contingent Payment	**(80)**	164	50
(Gain) Loss on Divestiture of Assets	**(81)**	(2)	795
Other (Income) Loss, Net	**40**	9	13
	546	597	3,340

(1) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.
(2) Onerous contract provisions of $629 million in 2018 have been reclassified to G&A.

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 2020, G&A expenses were $39 million lower primarily due to lower employee long-term incentive costs and operating costs associated with our real estate portfolio, partially offset by an onerous contract provision of $18 million.

Finance Costs

Finance costs increased by $25 million primarily due to a discount of $25 million on the repurchase of unsecured notes compared with $63 million in 2019.

The weighted average interest rate on outstanding debt for the year ended December 31, 2020 was 4.9 percent (2019 – 5.1 percent).

Foreign Exchange

($ millions)	**2020**	2019	2018
Unrealized Foreign Exchange (Gain) Loss	**(131)**	(827)	649
Realized Foreign Exchange (Gain) Loss	**(50)**	423	205
	(181)	(404)	854

In 2020, unrealized foreign exchange gains of $131 million were recorded primarily as a result of the translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar as at December 31, 2020 was two percent stronger compared with December 31, 2019, resulting in unrealized gains.

Transaction Costs

Prior to December 31, 2020, we incurred transaction costs of $29 million for costs related to the Arrangement, excluding common share, preferred share and warrant issuance costs.

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 Conoco 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 $63 million as at December 31, 2020 was estimated by calculating the present value of the future expected cash flows using an option pricing model. The contingent payment is re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. For the year ended December 31, 2020, a non-cash re-measurement gain of $80 million was recorded.

Average WCS forward pricing for the remaining term of the contingent payment is $42.93 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately $42.40 per barrel and $43.80 per barrel.

Other (Income) Loss, Net

For the year ended December 31, 2020, recorded a $100 million loss related to the Keystone XL pipeline project.

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 June 2021. For the year ended December 31, 2020, we recorded $40 million in other income from the CEWS program.

In 2020, we recognized $24 million of lease income (2019 - $17 million). Lease income is earned on tank subleases, operating leases related to our real estate ROU assets in which we are the lessor, and from the recovery of non-lease components for operating costs and unreserved parking related to our net investment in finance leases. Finance leases are included in other assets as net investment in finance leases.

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 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 2020 was $161 million (2019 – $107 million), of which $52 million of previously capitalized PP&E costs relating to information technology assets were written off due to synergies identified as a result of the Arrangement.

Income Tax

($ millions)	2020	2019	2018
Current Tax			
Canada	**(14)**	14	(128)
United States	**1**	3	2
Current Tax Expense (Recovery)	**(13)**	17	(126)
Deferred Tax Expense (Recovery)	**(838)**	(814)	(884)
Total Tax Expense (Recovery)	**(851)**	(797)	(1,010)

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

($ millions)	2020	2019	2018
Earnings (Loss) From Continuing Operations Before Income Tax	**(3,230)**	1,397	(3,926)
Canadian Statutory Rate (percent)	**24.0**	26.5	27.0
Expected Income Tax Expense (Recovery) From Continuing Operations	**(775)**	370	(1,060)
Effect of Taxes Resulting From:			
Statutory and Other Rate Differences	**19**	(52)	(57)
Non-Taxable Capital (Gains) Losses	**(42)**	(38)	89
Non-Recognition of Capital (Gains) Losses	**(42)**	(39)	87
Adjustments Arising from Prior Year Tax Filings	**(8)**	4	3
Alberta corporate rate reduction	**(7)**	(671)	-
Recognition of U.S. Tax Basis	**-**	(387)	(78)
Other	**4**	16	6
Total Tax Expense (Recovery) From Continuing Operations	**(851)**	(797)	(1,010)
Effective Tax Rate (percent)	**26.3**	(57.1)	25.7

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 year ended December 31, 2020, a deferred tax recovery was recorded due to an impairment of the Borger CGU, Conventional CGUs and current period operating losses that will be carried forward, excluding unrealized foreign exchange gains and losses on long-term debt. In 2020, the Government of Alberta accelerated the reduction in the provincial corporate tax rate from 12 percent to eight percent.

In 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, the Company recorded a deferred income tax recovery of $671 million for the year ended December 31, 2019. In addition, the Company recorded a deferred income tax recovery of $387 million due to an internal restructuring of the Company's U.S. operations resulting in a step-up in the tax basis of the Company's refining assets.

In 2018, the Company recorded a deferred tax recovery related to current period losses, including the write-down of the Conventional E&E assets and a $78 million recovery arising from an adjustment to the tax basis of the Company's refining assets. The increase in tax basis was a result of the Company's partner recognizing a taxable gain on its interest in WRB Refining LP ("WRB"), which due to an election filed with the U.S. tax authorities, was added to the tax basis of WRB's assets. The maximum recovery related to the carry back of losses to recover tax paid was reached in 2018.

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 $60 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.

DISCONTINUED OPERATIONS

On January 5, 2018, we completed the sale of the Suffield crude oil and natural gas operations in southern Alberta for cash proceeds of $512 million, before closing adjustments. After-tax earnings from discontinued operations for the year ended December 31, 2018 were $27 million. An after-tax gain on discontinuance of $220 million was recorded on the sale.

QUARTERLY RESULTS

Our results over the last four quarters were impacted by the volatility in commodity prices primarily due to the impacts of COVID-19 and OPEC and non-OPEC production output decisions. Light oil benchmark prices were low and volatile throughout the majority of 2020, compared with the price of WTI in 2019. WTI fell 19 percent to average US$46.17 per barrel in the first quarter compared with US$56.96 per barrel in the fourth quarter of 2019 and dropped further to average US$27.85 per barrel in the second quarter with a recovery to average US$42.66 per barrel in the fourth quarter. Average WTI and WCS benchmark prices decreased 25 percent and 19 percent, respectively in the fourth quarter of 2020 compared with 2019. As a result, our Operating Margin from continuing operations was $625 million in the fourth quarter of 2020, a decrease from $864 million in the fourth quarter of 2019. Net Loss was $153 million compared with Net Earnings of $113 million in 2019.

Selected Operating and Consolidated Financial Results

($ millions, except per share amounts)	2020				2019			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Commodity Prices								
Brent	**45.24**	43.37	33.27	50.96	62.50	62.00	68.34	63.88
WTI	**42.66**	40.93	27.85	46.17	56.96	56.45	59.83	54.90
WCS	**33.36**	31.84	16.38	25.64	41.13	44.21	49.18	42.53
Chicago Market Crack Spread	**7.05**	7.89	6.44	8.79	12.27	16.72	21.44	13.57
Production Volumes								
Liquids (barrels per day)	**405,280**	411,788	400,050	416,802	400,329	380,699	371,390	370,983
Natural Gas (MMcf per day)	**371**	360	392	395	403	407	432	458
Total Production (BOE per day)	**467,202**	471,799	465,415	482,594	467,448	448,496	443,318	447,270
Refinery Operations								
Crude Oil Runs (Mbbls/d)	**338**	382	325	442	456	465	474	375
Refined Products (Mbbls/d)	**350**	397	332	460	477	485	501	402
Revenues	**3,426**	3,659	2,174	3,968	4,838	4,736	5,603	5,004
Operating Margin [1]	**625**	594	291	(589)	864	1,080	1,277	1,239
Cash From (Used in) Operating Activities	**250**	732	(834)	125	740	834	1,275	436
Adjusted Funds Flow [2]	**341**	414	(462)	(146)	687	928	1,082	1,005
Operating Earnings (Loss)	**(551)**	(452)	(414)	(1,187)	(164)	284	267	69
Per Share [3] ($)	**(0.45)**	(0.37)	(0.34)	(0.97)	(0.13)	0.23	0.22	0.06
Net Earnings (Loss)	**(153)**	(194)	(235)	(1,797)	113	187	1,784	110
Per Share [3] ($)	**(0.12)**	(0.16)	(0.19)	(1.46)	0.09	0.15	1.45	0.09
Capital Investment [4]	**242**	148	147	304	317	294	248	317
Dividends								
Cash Dividends	**-**	-	-	77	77	60	62	61
Per Share ($)	**-**	-	-	0.0625	0.0625	0.0500	0.0500	0.0500

(1) Additional subtotal found in Note 1 of the Consolidated Financial Statements and interim Consolidated Financial Statements, and defined in this MD&A.
(2) 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.
(3) Represented on a basic and diluted per share basis.
(4) Includes expenditures on PP&E and E&E assets.

Fourth Quarter 2020 Results Compared With the Fourth Quarter 2019

Production Volumes

Total production in the fourth quarter of 2020 was in line with 2019. The fourth quarter reflects increased production levels in response to an improved pricing environment facilitated by the purchase of production curtailment credits and lifting of the mandatory curtailment level at the beginning of December 2020. This was partially offset by a planned turnaround and maintenance at Christina Lake and operational outages due to process treatment upsets at Foster Creek. In the fourth quarter of 2019, production was limited due to mandatory production curtailments set by the Government of Alberta, offset by curtailment relief equivalent to incremental increases in rail shipments from the Special Production Allowance ("SPA").

In the fourth quarter of 2020, we sold 121,595 barrels per day, approximately 25 percent, of our Oil Sands production at sales locations outside of Alberta compared with 181,366 barrels per day, approximately 35 percent, in the fourth quarter of 2019.

Conventional production in the fourth quarter of 2020 decreased eight percent to 86,167 BOE per day mainly due to natural declines from lower sustaining capital investment. Production from the Marten Hills assets was approximately 2,000 barrels per day for the quarter.

Refining and Marketing Operations

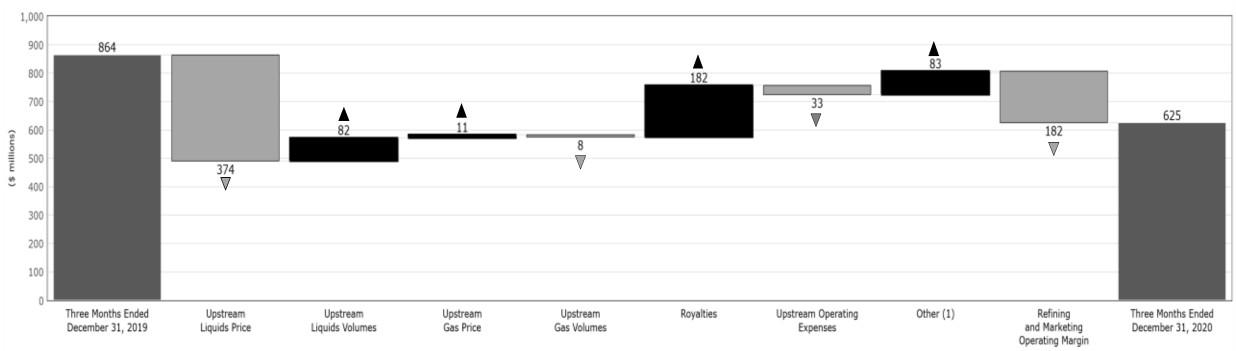
Crude oil runs of 338,000 gross barrels per day and refined product output of 350,000 gross barrels per day were lower compared with the same period in 2019 due to economic crude rate reductions in response to reduced demand as a result of COVID-19. In the fourth quarter of 2019 operations were impacted by planned turnaround activities and a crude supply constraint at Wood River as a result of a Keystone pipeline leak, partially offset by optimization of the total crude input slate.

In the fourth quarter of 2020, our crude-by-rail program was reinstated from the temporary suspension announced earlier in the year. Total rail volumes loaded at our Bruderheim crude-by-rail terminal averaged 29,144 barrels per day (20,423 barrels per day of our volumes) in the fourth quarter of 2020 compared with 89,630 barrels per day (71,708 barrels per day of our volumes) in the same period of 2019.

Revenues

Total revenues decreased $1,412 million in the fourth quarter of 2020 compared with the same period of 2019. Refining and Marketing revenues decreased $1,210 million primarily due to lower refined product pricing consistent with the declines in the average refined product benchmark prices and lower refined product output due to the economic crude rate reductions, and decreased revenues from third-party crude oil and natural gas sales undertaken by the marketing group. Upstream revenues decreased by $256 million primarily due to lower realized liquids sales pricing of $38.57 per barrel compared with $47.12 per barrel in 2019, partially offset by lower royalties and decreased sales volumes.

Operating Margin From Continuing Operations Variance



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

Operating Margin

Operating Margin decreased in the fourth quarter of 2020 due to:

- A lower average liquids sales price as a result of decreased crude oil benchmark prices;
- Lower Operating Margin from our Refining and Marketing segment due to lower market crack spreads, decreased crude oil runs, lower crude advantage; and
- Increased upstream operating expenses.

These decreases were partially offset by lower royalties primarily due to our lower realized crude oil sales price and a decrease in our transportation and blending costs due to a decrease in rail transportation costs.

Cash From Operating Activities and Adjusted Funds Flow

Total Cash From Operating Activities and Adjusted Funds Flow decreased in the fourth quarter of 2020 compared with the same period in 2019, primarily due to lower Operating Margin, as discussed above, transaction costs of $29 million and changes in non-cash working capital. Adjusted Funds Flow was further reduced by a $100 million loss related to the Keystone XL pipeline project.

The change in non-cash working capital in the fourth quarter of 2020 was primarily due to an increase in accounts receivable and inventory, a decrease in income tax payable, and an increase in income tax receivable, partially offset by an increase in accounts payable. For 2019, the change in non-cash working capital was primarily due to an increase in accounts payable and a decrease in income tax receivable, partially offset by an increase in accounts receivable and inventory.

Operating Earnings (Loss)

Operating Loss increased in the three months ended December 31, 2020 compared with 2019 primarily due to higher DD&A due to $298 million in impairments and write-downs, lower Cash From Operating Activities and Adjusted Funds Flow, as discussed above, and higher non-cash employee long-term incentive costs mainly as a result of the accelerated vesting of our Employee Stock Option Plan, performance share units ("PSUs") and restricted share units ("RSUs") held by non-executive employees due to the closing of the Arrangement, partially offset by non-operating realized foreign exchange losses of $nil compared with $122 million in 2019.

Net Earnings (Loss)

Net Loss of $153 million increased for the three months ended December 31, 2020 compared with Net Earnings of $113 million in 2019. The change was primarily due to higher Operating Loss, as discussed above, partially offset by non-operating unrealized foreign exchange gains of $358 million compared with $258 million in 2019 and a deferred income tax recovery of $182 million compared with $24 million in 2019.

Capital Investment

Capital investment from continuing operations in the fourth quarter of 2020 was $242 million, $75 million lower compared with the fourth quarter of 2019, primarily due to the reduction of our capital investment program in response to COVID-19.

OIL AND GAS RESERVES

We retain IQREs to evaluate and prepare reports on 100 percent of our bitumen, heavy crude oil, light and medium oil, NGLs, conventional natural gas and shale gas proved and probable reserves.

Reserves

As at December 31, 2020 (before royalties)	Bitumen (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas (1) (Bcf)	Total (MMBOE)
Proved	4,812	7	50	965	5,030
Probable	1,520	6	31	601	1,656
Proved plus Probable	6,332	13	81	1,566	6,686

As at December 31, 2019 (before royalties)	Bitumen (2) (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas (1) (Bcf)	Total (MMBOE)
Proved	4,826	9	60	1,242	5,103
Probable	1,594	8	37	783	1,768
Proved plus Probable	6,420	17	97	2,025	6,871

(1) Includes shale gas reserves that are not material.
(2) Includes heavy crude oil reserves that are not material.

Developments in 2020 compared with 2019 include:

- Bitumen proved and proved plus probable reserves decreasing 14 million barrels and 88 million barrels, respectively, as additions from improved performance in Oil Sands were more than offset by the Marten Hills disposition and current year production;
- Light and medium oil proved and proved plus probable reserves decreasing two million barrels and four million barrels, respectively, as minor additions were more than offset by technical revisions attributed to updates to the Conventional development plan, reduced product pricing and current year production;
- NGLs proved and proved plus probable reserves decreasing 10 million barrels and 16 million barrels, respectively, as minor additions and a minor acquisition were more than offset by reductions due to technical revisions attributed to updates to the Conventional development plan, reduced product pricing and current year production; and
- Conventional natural gas proved and proved plus probable reserves decreasing 277 billion cubic feet and 459 billion cubic feet, respectively, as minor additions and a minor acquisition were more than offset by

reductions due to technical revisions attributed to updates to the Conventional development plan, reduced product pricing and current year production.

The reserves data is presented as at December 31, 2020 using an average of forecasts ("IQRE Average Forecast") by McDaniel & Associates Consultants Ltd. ("McDaniel"), GLJ Ltd. ("GLJ") and Sproule Associates Limited ("Sproule"). The IQRE Average Forecast prices and costs are dated January 1, 2021. Comparative information as at December 31, 2019 uses the January 1, 2020 IQRE Average Forecast prices and costs.

As a result of the close of the Arrangement on January 1, 2021, including reported reserves from Husky, our total proved reserves and total proved plus probable reserves are anticipated to increase by approximately 1.2 billion BOE and 1.8 billion BOE, respectively.

Additional information with respect to the evaluation and reporting of our reserves in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") is contained in our AIF for the year ended December 31, 2020. Our AIF is available on SEDAR at sedar.com, on EDGAR at sec.gov and on our website at cenovus.com. Material risks and uncertainties associated with estimates of reserves are discussed in this MD&A in the Risk Management and Risk Factors section and the Advisory section in this MD&A.

Information concerning Husky and its reserves data and other oil and gas information as of December 31, 2020 may be found in the Husky AIF and the Husky MD&A, each of which is filed and available on SEDAR under Husky's profile at sedar.com.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	**2020**	2019	2018
Cash From (Used in)			
Operating Activities	**273**	3,285	2,154
Investing Activities	**(863)**	(1,432)	(613)
Net Cash Provided (Used) Before Financing Activities	**(590)**	1,853	1,541
Financing Activities	**837**	(2,413)	(1,410)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(55)**	(35)	40
Increase (Decrease) in Cash and Cash Equivalents	**192**	(595)	171

As at December 31,	**2020**	2019	2018
Cash and Cash Equivalents	**378**	186	781
Debt	**7,562**	6,699	9,164

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

Cash From (Used in) Operating Activities

For the year ended December 31, 2020, cash generated by operating activities decreased mainly due to lower Operating Margin, transaction costs of $29 million, partially offset by funding from the CEWS program and sublease income, 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 the current portion of the contingent payment, our working capital was $653 million at December 31, 2020 compared with $842 million at December 31, 2019.

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

Cash From (Used in) Investing Activities

Cash used in investing activities was lower in 2020 compared with 2019 primarily due to decreased capital investment in 2020.

Cash From (Used in) Financing Activities

In the first quarter of 2020, we repurchased US$100 million of unsecured notes for cash of US$81 million. In the third quarter of 2020 we issued US$1.0 billion in 5.375 percent senior unsecured notes due in 2025 and used the proceeds to repay $1.4 billion of borrowings on our committed credit facility.

In 2019, cash was used in financing activities primarily for the repayment of debt. We repaid US$1.8 billion of unsecured notes for cash consideration of US$1.7 billion ($2.3 billion).

Total debt, including short-term borrowings, as at December 31, 2020 was $7,562 million (December 31, 2019 – $6,699 million).

Common Share Dividends

On April 2, 2020 we announced the temporary suspension of our common share dividend in response to the low global crude oil price environment. Prior to the suspension, we paid common share dividends of $77 million or 0.0625 per common share in the first quarter of 2020 (year ended December 31, 2019 – $260 million or $0.2125 per common share). The declaration of dividends is at the sole discretion of the Board and is considered quarterly. The Board declared a first quarter dividend of $0.0175 per common share, payable on March 31, 2021 to common shareholders of record as of March 15, 2021.

Cumulative Redeemable Preferred Share Dividend

The Board declared a first quarter dividend on the Series 1, 2, 3, 5, and 7 preferred shares, payable on March 31, 2021, in the amount of $8 million.

Available Sources of Liquidity

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

($ millions)	Term	Amount Available
Cash and Cash Equivalents	**Not applicable**	**378**
Committed Credit Facilities		
Revolving Credit Facility – Tranche A	**November 2023**	**3,300**
Revolving Credit Facility – Tranche B	**November 2022**	**1,200**
Uncommitted Demand Facilities		
Cenovus Energy Inc.	**Not applicable**	**600**
WRB Refining LP (Cenovus's proportionate share)	**Not applicable**	**70**

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 demand facilities and other corporate and financial opportunities that may be available to us.

Committed Credit Facilities

As at December 31, 2020, we had a total committed credit facility of $4.5 billion that consisted 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 was renewable for one year at our request and upon approval by the lenders, to further support our financial resilience. On December 31, 2020, we cancelled the $1.1 billion committed credit facility. As at December 31, 2020, no amount was drawn on the committed credit facility (December 31, 2019 - $265 million).

Uncommitted Demand Facilities

As at December 31, 2020, Cenovus had 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 December 31, 2020, the Company had drawn no amounts (December 31, 2019 - $nil) on these facilities and there were outstanding letters of credit aggregating to $441 million (December 31, 2019 - $364 million).

WRB 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 December 31, 2020, US$190 million was drawn on these facilities, of which US$95 million ($121 million) was the Company's proportionate share (December 31, 2019 – $nil).

Base Shelf Prospectus

Cenovus has in place a base shelf prospectus that allows us to offer, from time to time, up to US$5.0 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere where permitted by law. The base shelf prospectus will expire in October 2021. On July 30, 2020, we completed a public offering in the U.S., under the U.S. base shelf prospectus, of senior unsecured notes in the aggregate principal amount of US$1.0 billion due in 2025. As at December 31, 2020, US$3.7 billion remained available under the base shelf prospectus for permitted offerings.

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 (recovery), 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.

As at December 31,	**2020**	2019	2018
Net Debt to Capitalization (1) (percent)	**30**	25	32
Net Debt to Adjusted EBITDA (times)	**11.9x**	1.6x	5.8x

(1) *Net Debt to Capitalization is defined as Net Debt divided by Net Debt plus Shareholders' Equity.*
(2) *On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.*

A reconciliation of Adjusted EBITDA, and the calculation of Net Debt to Adjusted EBITDA can be found in Note 24 of the Consolidated Financial Statements.

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, repurchase our common shares for cancellation, issue new debt, or issue new shares.

As at December 31, 2020, Cenovus's Net Debt to Adjusted EBITDA was 11.9 times. Net Debt to Adjusted EBITDA increased compared with December 31, 2019 as a result of 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.

We also manage our Net Debt to Capitalization ratio to ensure compliance with the associated covenants as defined in our committed credit facility agreements. Under the terms of Cenovus's committed credit facility at the end of the year, we were 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 December 31, 2020.

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

Share Capital and Stock-Based Compensation Plans

As at December 31, 2020, there were approximately 1,229 million common shares outstanding (2019 – 1,229 million common shares). Refer to Note 30 of the Consolidated Financial Statements for more details.

Refer to Note 32 of the Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and deferred share unit ("DSU") Plans.

Our outstanding share data is as follows:

As at January 31, 2021	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares (1)	**2,017,404**	**N/A**
Common Share Warrants	**65,418**	**N/A**
Preferred Shares Series 1	**10,436**	**N/A**
Preferred Shares Series 2	**1,564**	**N/A**
Preferred Shares Series 3	**10,000**	**N/A**
Preferred Shares Series 5	**8,000**	**N/A**
Preferred Shares Series 7	**6,000**	**N/A**
Stock Options (2)	**30,499**	**23,305**
Other Stock-Based Compensation Plans	**3,715**	**1,293**

(1) *ConocoPhillips continued to hold 208 million common shares issued as partial consideration related to the Conoco Acquisition.*
(2) *Includes Cenovus Replacement Options (defined below) issued pursuant to the Arrangement in replacement of all issued and outstanding Husky stock options.*

Capital Investment Decisions

Our approach on the financial framework of the combined company will be consistent with the parameters we have set for Cenovus in prior years. We will continue to evaluate all opportunities based on a US$45.00 per barrel WTI price with the objective of maintaining a prudent and flexible capital structure and strong balance sheet metrics. This approach positions us to be financially resilient in times of lower cash flows. Balance sheet strength continues to be a top priority and we plan to continue to direct our Free Funds Flow towards debt reduction. We continue to target a Net Debt to EBITDA ratio not to exceed two times.

Our 2021 capital program for the combined company is forecast to be between $2.3 billion and $2.7 billion. The budget is focused on maintaining safe and reliable operations while positioning the Company to drive enhanced shareholder value and includes sustaining capital of approximately $2.1 billion to deliver upstream production of approximately 755,000 BOE per day and downstream throughput of approximately 525,000 barrels per day.

($ millions)	**2020**	2019	2018
Adjusted Funds Flow (1)	**147**	3,702	1,721
Total Capital Investment	**841**	1,176	1,363
Free Funds Flow (1) (2)	**(694)**	2,526	358
Cash Dividends	**77**	260	245
	(771)	2,266	113

(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 remain committed to maintaining and improving our current investment-grade credit ratings. This includes our continued focus on allocating free funds flow to reduce Net Debt to less than $10 billion and targeting a longer-term Net Debt level at or below $8 billion.

The combined company's adjusted funds flow is expected to fully fund sustaining capital and shareholder distributions. The Board declared a first quarter dividend of $0.0175 per common share, payable on March 31, 2021, to common shareholders of record as of March 15, 2021. The Board declared a first quarter dividend on the Series 1, 2, 3, 5, and 7 preferred shares, payable on March 31, 2021, in the amount of $8 million.

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 Consolidated Financial Statements.

As at December 31, 2020, total commitments were $23 billion, of which $21 billion are for various transportation and storage commitments. 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. Transportation and storage commitments include future commitments relating to storage tank leases of $31 million, that have not yet commenced.

	Expected Payment Date						
($ millions)	2021	2022	2023	2024	2025	Thereafter	**Total**
Commitments							
Transportation and Storage (1)	1,014	954	1,341	1,444	1,107	15,537	**21,397**
Real Estate (2)	34	36	38	41	44	604	**797**
Capital Commitments	1	2	-	-	-	-	**3**
Other Long-Term Commitments	104	45	32	32	24	85	**322**
Total Commitments (3)	1,153	1,037	1,411	1,517	1,175	16,226	**22,519**
Other Obligations							
Long-term Debt (Principal and Interest)	385	1,024	941	346	1,620	8,627	**12,943**
Decommissioning Liabilities	41	45	41	42	41	2,429	**2,639**
Contingent Payment	36	28	-	-	-	-	**64**
Lease Liabilities (Principal and Interest) (4)	254	237	208	203	162	1,412	**2,476**
Total Commitments and Obligations	1,869	2,371	2,601	2,108	2,998	28,694	**40,641**

(1) Includes transportation commitments of $14 billion (December 31, 2019 – $13 billion) that are subject to regulatory approval or have been approved but are not yet in service.
(2) Relates to the non-lease components of lease liabilities consisting of operating costs and unreserved parking for office space. Excludes committed payments for which a provision has been provided.
(3) Contracts undertaken on behalf of WRB are reflected at our 50 percent interest.
(4) Lease contracts related to office space, railcars, storage assets, drilling rigs and other refining and field equipment.

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 December 31, 2020, there were outstanding letters of credit aggregating $441 million issued as security for performance under certain contracts (December 31, 2019 – $364 million).

Liquidity and Capital Resources Subsequent to the Arrangement

Share Capital and Stock-Based Compensation

At the closing of the Arrangement on January 1, 2021, we acquired all of the issued and outstanding Husky common shares in consideration for the issuance of 0.7845 Cenovus common shares and 0.0651 Cenovus warrants ("Cenovus Warrants") for each Husky common share. All the issued and outstanding Husky preferred shares were exchanged for Cenovus preferred shares with substantially identical terms, and all issued and outstanding Husky stock options were exchanged for Cenovus replacement stock options ("Cenovus Replacement Options"). Each Cenovus Replacement Option entitles the holder to acquire 0.7845 of a Cenovus common share at an exercise price per share of a Husky stock option divided by 0.7845. Refer to Notes 30 and 39 of the Consolidated Financial Statements for more details.

The Arrangement resulted in the accelerated vesting of certain stock-based compensation plans of the Company. Refer to Notes 32 and 39 of the Consolidated Financial Statements for more details. In accordance with their terms, the PSUs and RSUs may be settled, at the discretion of Cenovus, in Cenovus common shares, cash, or a combination of both based on the 30-day volume weighted average trading price prior to the date of closing. The obligations associated all PSUs and RSUs that were settled in connection with the completion of the Arrangement were paid in cash in January 2021.

In connection with the Arrangement, a DSU holder that ceased to be a Cenovus director or employee will be entitled to the settlement and redemption of their DSUs, in cash based on the five day volume weighted average trading prior to the date of redemption, in accordance with the terms of the related DSU Plan.

Liquidity and Commitments

At closing of the Arrangement on January 1, 2021, Cenovus obtained access to additional sources of capital including: $735 million in cash and cash equivalents, $3.7 billion available on Husky's committed credit facilities and $508 million available on Husky's uncommitted demand facilities. Husky's committed credit facilities have a capacity of $4.0 billion and its uncommitted demand facilities have a capacity of $975 million, of which $850 million may be drawn for general purposes, or the full amount can be available to issue letters of credit.

We remain committed to maintaining our investment grade credit ratings at S&P Global Ratings, Moody's Investor Service ("Moody's") and DBRS Limited and re-establishing investment grade ratings at 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.

The Arrangement resulted in the assumption of Husky's known non-cancellable contracts and other commercial commitments. On January 1, 2021, total commitments assumed by Cenovus were $19 billion, of which $2 billion were for various transportation commitments that are subject to regulatory approval or have been approved, but are not yet in service.

Additional information concerning Husky's liquidity and commitments as of December 31, 2020 may be found under the sections Sources of Liquidity and Contractual Obligations, Commitments and Off-Balance Sheet Arrangements in the Husky MD&A, which is filed and available on SEDAR under Husky's profile at sedar.com.

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 Conoco 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 December 31, 2020, the estimated fair value of the contingent payment was $63 million. As at December 31, 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

We are exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the energy 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.

Our Enterprise Risk Management ("ERM") program drives the identification, measurement, prioritization, and management of Cenovus's risk and is integrated with our Operations Management Systems. In addition, we continuously monitor our risk profile as well as industry best practices.

Risk Governance

The *ERM Policy*, approved by our Board, outlines our risk management principles and expectations, as well as the roles and responsibilities of all staff. Building on the *ERM Policy*, we have established risk management standards, a risk management framework and risk assessment tools, including risk matrices. Our risk management framework contains the key attributes recommended by the International Organization for Standardization ("ISO") in its ISO 31000 – Risk Management Guidelines. The results of our ERM program are documented in an Annual Risk Report presented to the Board as well as through regular updates.

Risk Factors

The following discussion describes the financial, operational, regulatory, environmental, reputational and other risks related to Cenovus. Each risk identified in this MD&A may individually, or in combination with other risks, have a material impact on our business, financial condition, results of operations, cash flows, or reputation and should be considered when purchasing securities of Cenovus.

Pandemic Risk

The COVID-19 pandemic and measures taken in response by governments and health authorities around the world have resulted in a significant slow-down in global economic activity that has reduced the demand for, and adversely affected the prices of, commodities that are closely linked to Cenovus's financial performance, including crude oil, refined products (such as jet fuel, diesel and gasoline), natural gas and electricity, and also increases the risk that storage for crude oil and refined products could reach capacity in certain geographic locations in which Cenovus operates variant strains of COVID-19 have been identified. While some economies have started to re-open and vaccines have been developed, resurgences in cases of COVID-19 have occurred in certain locations and the risk of additional resurgences in other locations remains high. This creates ongoing uncertainty that has resulted in and could result in further 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 this 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;
- Disruptions to global supply chains, such as 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;
- Commodity storage constraints resulting in the curtailment or shutting in of production;
- A decrease in refined product volumes, the demand for refined products, or refinery utilization rates;
- 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, customers, and partners 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 severity, duration, spread or resurgence of COVID-19 or any variants thereof; the timing, extent and effectiveness of actions taken to contain or treat COVID-19 or its variants, including the availability, distribution rate and effectiveness of any vaccines; and the speed and extent to which normal economic and operating conditions resume. The potential impacts of COVID-19 to our business, results of operations and financial condition could be more significant in the current year as compared with 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.

We have taken proactive steps to protect the health and safety of our staff and the continuity of our business in response to the COVID-19 pandemic. We continue to follow guidance received from the Federal, Provincial and state governments and public health officials. 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. Despite our best efforts, the COVID-19 pandemic may result in new legal disputes, including class action claims.

Financial Risk

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions. Financial risks include, but are not limited to: fluctuations in commodity prices, development or operating costs; risks related to Cenovus's hedging activities; exposure to counterparties; availability of capital and access to sufficient liquidity; risks related to Cenovus's credit ratings; and fluctuations in foreign exchange and interest rates. In addition, we identify risks related to our ability to pay a dividend to shareholders; and risks related to internal control over financial reporting ("ICFR"). Changes in financial management and/or market conditions could impact a number of factors including, but not limited to, Cenovus's cash flows, Cenovus's ability to maintain desirable ratios of debt (and Net Debt) to Adjusted EBITDA as well as debt (and Net Debt) to capitalization, Cenovus's financial condition, results of operations and growth, the maintenance of our existing operations and business plans, financial strength of our counterparties, access to capital and cost of borrowing.

Excess Crude Oil Supply Risk

It is not known how long low commodity price conditions will continue, however if the situation continues, worsens or is exacerbated further by the impact of COVID-19, and global crude oil prices remain low for a prolonged period, our production, project development, profitability, cash flows, ability to access additional capital, and securities trading price, among other things, could be adversely impacted. While OPEC members agreed to certain production cuts through April 2022 and have reconfirmed their commitment to a stable oil market amid the global demand reduction caused by the pandemic, the stated reductions have since been varied and there can be no assurances that OPEC members and other oil exporting nations will abide by the agreed reductions or 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

Our financial performance is significantly dependent on the prevailing prices of crude oil, refined products, natural gas and NGLs. Crude oil prices are impacted by a number of factors including, but not limited to: global and regional supply of and demand for crude oil; global economic conditions including factors impacting global trade; the actions of OPEC and other oil exporting nations including, without limitation, compliance or non-compliance with quotas agreed upon by OPEC members and decisions by OPEC not to impose production quotas on its members; actions by the Government of Alberta including, without limitation, imposing, amending, or lifting crude oil production curtailments or SPA for crude-by-rail, and compliance or non-compliance with imposed crude oil production curtailments or SPA for crude-by-rail; enforcement of government or environmental regulations; public sentiment towards the use of non-renewable resources, including crude oil; political stability and social conditions in oil producing countries, market access constraints and transportation interruptions (pipeline, marine or rail); prices and availability of alternate fuel sources; outbreak of war; outbreak or continuation of a pandemic; terrorist threats; technological developments; the occurrence of natural disasters; and weather conditions.

Cenovus's natural gas and NGL production is currently located in Western Canada and Asia Pacific. Western Canadian natural gas prices are impacted by a number of factors including, but not limited to: North American supply and demand; developments related to the market for liquefied natural gas; prices and availability of alternate sources of energy; government or environmental regulations; public sentiment towards the use of non-renewable resources, including natural gas and NGLs; market access constraints and transportation interruptions; economic conditions; technological developments; the occurrence of natural disasters; and weather conditions.

Refined product prices are impacted by a number of factors including, but not limited to: global and regional supply and demand for refined products; market competitiveness; levels of refined product inventories; refinery availability; planned and unplanned refinery maintenance; current and potential future environmental regulations pertaining to the production and use of refined products; prices and availability of alternate sources of energy; public sentiment towards the use of refined products; prices and the availability of alternate fuel sources; technological developments; the occurrence of natural disasters; and weather conditions. In addition, and relating to the level of future demand (and corresponding price levels) for each of crude oil, refined products and natural gas, there has been a significant increase in focus recently on the timing for and pace of the transition to a lower-carbon economy. See "Climate Change Transition – Demand and Commodity Prices" below. All of these factors are beyond our control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars.

Our financial performance is also impacted by discounted or reduced commodity prices for our oil sands production relative to certain international benchmark prices, due, in part, to constraints on the ability to transport and sell products to domestic or international markets and the quality of oil produced. Of particular importance to us are diluent cost and supply and the price differentials between bitumen and both light to medium crude oil and heavy crude oil. Bitumen is more expensive for refineries to process and therefore generally trades at a discount to the market price for light and medium crude oil and heavy crude oil.

The financial performance of our refining operations is impacted by the relationship, or margin, between refined product prices and the prices of refinery feedstock. Refining margins are subject to seasonal factors as production changes to match seasonal demand. Sales volumes, prices, inventory levels and inventory values will fluctuate accordingly. Future refining margins are uncertain and decreases in refining margins may have a negative impact on our business.

Fluctuations in the price of commodities, associated price differentials and refining margins may impact our ability to meet guidance targets, the value of our assets, our cash flows and our ability to maintain our business and fund projects. A substantial decline in these commodity prices or extended period of low commodity prices may result in an inability to meet all of our financial obligations as they come due, a delay or cancellation of existing or future drilling, development or construction programs, curtailment in production (independent of any crude oil production curtailment mandated by the Government of Alberta then in effect), unutilized long-term transportation commitments and/or low utilization levels at Cenovus's refineries. 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.

The commodity price risks noted above, as well as other risks such as market access constraints and transportation restrictions, reserves replacement and reserves estimates, and cost management that are more fully described herein, and may have a material impact on our business, financial condition, results of operations, cash flows or reputation, may be considered to be indicators of impairment. Another indication of impairment is the comparison of the carrying value of our assets to our market capitalization.

As discussed in this MD&A, we conduct an assessment, at each reporting date, of the carrying value of our assets in accordance with IFRS. If crude oil, refined product and natural gas prices decline significantly and remain at low levels for an extended period of time, or if the costs of our development of such resources significantly increases, the carrying value of our assets may be subject to impairment and our net earnings could be adversely affected.

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. In certain instances, Cenovus will use derivative instruments to manage exposure to price volatility on a portion of its refined product, oil and gas production, inventory or volumes in long-distance transit. 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 35 and 36 of the Consolidated Financial Statements and "Hedging Activities" below.

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, refined product and natural gas prices remain at low levels for an extended period, 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.

Development and Operating Costs

Our financial outlook and performance is significantly affected by the cost of developing, sustaining and operating our assets. Development and operating costs are affected by a number of factors including, but not limited to: development, adoption and success of new technologies; inflationary price pressure; changes in regulatory compliance costs; scheduling delays; failure to maintain quality construction and manufacturing standards; and supply chain disruptions, including access to skilled labour. Electricity, water, diluent, chemicals, supplies, reclamation, abandonment and labour costs are examples of operating costs that are susceptible to significant fluctuation.

Hedging Activities

Cenovus's *Market Risk Management Policy*, which has been approved by the Board, allows Management to use derivative instruments including exchange-traded future contracts, commodity put and call options and other approved instruments as needed to help mitigate the impact of changes in crude oil and natural gas prices, crude oil differentials, diluent or condensate supply prices and differentials, refined product and crack spread margins, as well as fluctuations in foreign exchange rates and interest rates. Cenovus may also use firm commitments for the purchase or sale of crude oil, natural gas and refined products. Cenovus also uses derivative instruments in various operational markets to help optimize our supply costs or sales of our production.

The use of such hedging activities exposes us to risks which may cause significant loss. These risks include, but are not limited to: changes in the valuation of the hedge instrument being not well correlated to the change in the valuation of the underlying exposures being hedged; change in price of the underlying commodity; lack of market liquidity; insufficient counterparties to transact with; counterparty default; deficiency in systems or controls; human error; and the unenforceability of contracts.

There is risk that the consequences of hedging to protect against unfavourable market conditions may limit the benefit to us of commodity price increases or changes in interest rates and foreign exchange rates. We may also suffer financial loss due to hedging arrangements if we are unable to produce oil, natural gas or refined products to fulfill our delivery obligations related to the underlying physical transaction.

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts and market access commitments. 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 3, 35 and 36 of the Consolidated Financial Statements.

Impact of Financial Risk Management Activities

In 2020, 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 as well as hedging activity related to the transportation of crude and condensate. 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 losses were recorded on our crude oil financial instruments in the twelve months ended December 31, 2020 primarily due to changes in commodity prices compared with prices at the end of the year 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.

Sensitivities – Risk Management Positions

The following table summarizes the sensitivities of the fair value of our risk management positions to fluctuations in commodity prices, with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuations in commodity prices on our open risk management positions could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$5.00 per bbl Applied to WTI and Condensate Hedges	**(44)**	**44**
Crude Oil Differential Price	± US$2.50 per bbl Applied to Differential Hedges Tied to Production	**(2)**	**2**

For further information on our risk management positions, see Notes 35 and 36 of the Consolidated Financial Statements.

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 Board-approved *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*.

Exposure to Counterparties

In the normal course of business, we enter into contractual relationships with suppliers, partners, lenders and other counterparties for the provision and sale of goods and services. If such counterparties do not fulfill their contractual obligations on a timely basis or at all, we may suffer financial losses, delays of our development plans or we may have to forego other opportunities which could materially impact our financial condition or operational results.

Credit, Liquidity and Availability of Future Financing

The future development of our business may be dependent on our ability to obtain additional capital including, but not limited to, debt and equity financing. Among other things, unpredictable financial markets, a sustained commodity price downturn, a change in market fundamentals, business operations, investor or lender sentiment towards our business and/or the industry in which we operate or credit rating, or significant unanticipated expenses, may impede our ability to secure and maintain cost-effective financing. An inability to access capital, on terms acceptable to Cenovus or at all, could affect our ability to make future capital expenditures, to maintain desirable ratios of debt (and Net Debt) to Adjusted EBITDA as well as debt (and Net Debt) to capitalization and to meet all of our financial obligations as they come due, potentially creating a material adverse effect on our financial condition, results of operations, ability to comply with various financial and operating covenants, credit ratings and reputation.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic, business, market and other conditions, some of which are beyond our control. If our operating and financial results are not sufficient to service current or future indebtedness, Cenovus may take actions such as reducing or suspending dividends, reducing or delaying business activities, investments or capital expenditures, selling assets, restructuring or refinancing our debt, or seeking additional capital that could have less favourable terms.

Our liquidity risk is mitigated through actively managing cash and cash equivalents, cash flow provided by operating activities, available credit facilities, and accessing the capital markets.

We are required to comply with various financial and operating covenants under our credit facilities and the indentures governing our debt securities. We routinely review our covenants to ensure compliance. In the event that we do not comply with such covenants, our access to capital could be restricted or repayment could be accelerated.

Credit Ratings

Our company and our capital structure are regularly evaluated by credit rating agencies. Credit ratings are based on our financial and operational strength and a number of factors not entirely within our control, including conditions affecting the oil and gas industry generally, industry risks associated with climate change and an energy transition and the state of the economy. There can be no assurance that one or more of our credit ratings will not be downgraded or withdrawn entirely by a rating agency.

A reduction in any of our credit ratings could adversely affect the cost and availability of borrowing, and access to sources of liquidity and capital. A failure by Cenovus to maintain current credit ratings could affect our business relationships with counterparties, operating partners and suppliers.

If one or more of our credit ratings falls below certain ratings thresholds, we may be obligated to post collateral in the form of cash, letters of credit or other financial instruments in order to establish or maintain business arrangements. Additional collateral may be required due to further downgrades below certain ratings thresholds. Failure to provide adequate credit risk assurance to counterparties and suppliers may result in foregoing or having contractual business arrangements terminated.

Foreign Exchange Rates

Fluctuations in foreign exchange rates between various currencies may affect our results. Global prices for crude oil, refined products, and natural gas are generally set in U.S. dollars, while many of our operating and capital costs are in Canadian dollars. A change in the value of the Canadian dollar relative to the U.S. dollar will increase or decrease revenues, as expressed in Canadian dollars, received from the sale of oil and refined products, and from some of our natural gas sales. In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in our U.S. dollar denominated debt and related interest expense, as expressed in Canadian dollars. We may periodically enter into transactions to manage our exposure to exchange rate fluctuations. However, the fluctuations in exchange rates are beyond our control and could have a material adverse effect on our cash flows, results of operations and financial condition.

Interest Rates

We may be exposed to fluctuations in interest rates as a result of the use of floating rate securities or borrowings. An increase in interest rates could increase our net interest expense and affect how certain liabilities are recorded, both of which could negatively impact financial results. Additionally, we are exposed to interest rate fluctuations upon the refinancing of maturing long-term debt and potential future financings at prevailing interest rates.

We may periodically enter into transactions to manage our exposure to interest rate fluctuations.

Dividend Payment and Repurchase of Securities

The payment of dividends, continuation of Cenovus's dividend reinvestment plan and any potential repurchase by Cenovus of its securities is at the discretion of the Board, and is dependent upon, among other things, financial performance, debt covenants, satisfying solvency testing, our ability to meet financial obligations as they come due, working capital requirements, future tax obligations, future capital requirements, commodity prices and other business and risk factors set forth in this MD&A.

Disclosure Controls and Procedures and ICFR

Based on their inherent limitations, disclosure controls and procedures and ICFR may not prevent or detect misstatements, and even those controls determined to be effective can only provide reasonable assurance with respect to financial statement preparation and presentation. Failure to adequately prevent, detect and correct misstatements could have a material adverse effect on our business, financial condition, results of operations, cash flows, and our reputation.

Operational Risk

Operational risks are those risks that affect our ability to continue operations in the ordinary course of business. Our operations are subject to risks generally affecting the energy industry. To partially mitigate our risks, we have a system of standards, practices and procedures to identify, assess and mitigate safety, operational and environmental risk across our operations. In addition, we attempt to partially mitigate operational risks by maintaining a comprehensive insurance program in respect of our assets and operations. However, there can be no assurance as to the amount, if any, or timing of recovery under our insurance policies in connection with losses associated with these events and risks. Although we maintain insurance for a number of risks and hazards, we may not be insured or fully insured against all losses or liabilities that could arise from our assets or operations.

Health and Safety

The operation of our properties is subject to hazards of finding, recovering, transporting, refining, processing and marketing hydrocarbons including, but not limited to: blowouts; fires; explosions; railcar incident or derailment; gaseous leaks; migration of harmful substances; loss of containment; releases or spills, including releases or spills from shipping vessels at terminals or hubs and as a result of pipeline or other leaks; corrosion; epidemics or pandemics; and catastrophic events, including, but not limited to, war, extreme weather events, natural disasters, acts of vandalism and terrorism; and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites. Any of these hazards can interrupt operations, impact our reputation, cause loss of life or personal injury, result in loss of or damage to equipment, property, information technology systems, related data and control systems, cause environmental damage that may include polluting water, land or air, and may result in fines, civil suits, or criminal charges against Cenovus, any of which may have a material adverse effect on our business, financial condition, results of operations, cash flows, and our reputation.

Aviation Incidents

Cenovus's Offshore operations in Canada and China rely on regular travel by helicopter. A helicopter incident resulting in loss of life, facility shutdown or regulatory action could have a material adverse effect on our operations. This risk is managed through an aviation management process. Aviation Safety Reviews are conducted by third party specialist contractors to verify that helicopter service providers meet Cenovus's and industry standards with respect to aviation safety. The reviews include evaluation of aircraft type, effectiveness of the safety and maintenance management systems and competency and training programs for critical roles in the operation of helicopters. Helicopters chartered to support Offshore operations must be fit for service and as such are fitted with multiple redundant systems to address a wide range of potential in-flight emergencies. Additional measures specific to our challenging operating environments are specified in our design requirements including anti-icing and floatation systems effective for the maximum allowable sea height operating limits. Pilots are trained to address potential emergency situations through regular real-time and simulator training aligned with industry best practice.

Ice Management

Although extensive measures are in place to prevent incidents related to sea ice and icebergs, our offshore operations are at risk of incidents caused by icebergs which may interrupt operations, impact our reputation, cause loss of life, personal injury, or damage to equipment or the environment, and may result in regulatory action or litigation against us. We have several policies in place to protect people, equipment and the environment in the event of extreme weather conditions and adverse ice conditions. We have developed Adverse Weather Guidelines for the SeaRose floating production, storage and offloading vessel and continue to manage physical risk through engineering for extreme weather events.

Our Atlantic operations have a robust ice management program, which uses a range of resources including an industry shared ice surveillance aircraft, as well as synergistic relationships with government agencies including Environment and Climate Change Canada, the Canadian Coast Guard and Canadian Ice Service. In addition, Atlantic operators employ a series of supply and support vessels to actively manage ice and icebergs. We also maintain a series of relationships with contractors on a stand-by basis, allowing the quick mobilization of additional resources as required. We regularly assess all aspects of our ice management program in order to ensure that the program continues to evolve as more information about the characteristics of ice and icebergs becomes available and as new technologies are developed.

Market Access Constraints and Transportation Restrictions

Our production is transported through various pipelines, marine and rail networks and our refineries are reliant on various pipelines and rail networks to receive feedstock. Disruptions in, or restricted availability of, pipeline service and/or marine or rail transport, could adversely affect crude oil, refined products and natural gas sales, projected production growth, upstream or refining operations and cash flows.

Interruptions or restrictions in the availability of these pipeline, marine and rail systems may also limit the ability to deliver production volumes and could adversely impact commodity prices, sales volumes and/or the prices received for our products. These interruptions and restrictions may be caused by, among other things, the inability of the pipeline, marine or rail networks to operate, or may be related to capacity constraints as the supply of feedstock into the system exceeds the infrastructure capacity. There can be no certainty that investments in new pipeline projects, which would result in an increase in long-term takeaway capacity, will be made by applicable third party pipeline providers that any applications to expand capacity will receive the required regulatory approval, or that any such approvals will result in the construction of the pipeline project or that such projects would provide sufficient transportation capacity and access to refining capacity. There is also no certainty that short-term operational constraints on the pipeline system, arising from pipeline interruption and/or increased supply of crude oil, will not occur.

There is no certainty that crude-by-rail, marine transport and other alternative types of transportation for our production will be sufficient to address any gaps caused by operational constraints on the pipeline system. In addition, our crude-by-rail and marine shipments may be impacted by service delays, inclement weather, railcar availability, railcar derailment or other rail or marine transport incidents and could adversely impact crude oil sales volumes or the price received for product or impact our reputation or result in legal liability, loss of life or personal injury, loss of equipment or property, or environmental damage. In addition, rail and marine regulations are constantly being reviewed to ensure the safe operation of the supply chain. Should regulations change, the costs of complying with those regulations will likely be passed on to rail and/or marine shippers and may adversely affect our ability to transport crude-by-rail and/or marine transport or the economics associated with rail transportation. Finally, planned or unplanned shutdowns or closures of our refineries or of our refinery customers may limit our ability to deliver product with negative implications on sales and cash from operating activities.

Operational Considerations

Our operations are subject to all of the risks normally incidental to: (i) the storing, transporting, processing, and marketing of crude oil, refined products, natural gas and other related products; (ii) drilling and completion of crude oil and natural gas wells; (iii) the operation and development of crude oil and natural gas properties; and (iv) the operation of refineries, terminals, pipelines and other transportation and distribution facilities. These risks include but are not limited to: encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; fires; explosions; blowouts; loss of containment; gaseous leaks; power outages; migration of harmful substances into water systems; oil spills; uncontrollable flows of crude oil, natural gas or well fluids; failure to follow operating procedures or operate within established operating parameters; adverse weather conditions; pollution; freeze-ups and other similar events; the breakdown or failure of equipment, pipelines and facilities, information systems and processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); releases or spills from offshore operations, shipping vessels or other marine transport incidents; railcar incidents or derailments; failure to maintain adequate supplies of spare parts; the compromise of information technology and control systems and related data; operator error; labour disputes; disputes with interconnected facilities and carriers; operational disruptions or apportionment on third-party systems or refineries, which may prevent the full utilization of the Company's facilities and pipelines; spills at truck terminals and hubs; spills associated with the loading and unloading of potentially harmful substances onto trucks; loss of product; unavailability of feedstock; price and quality of feedstock; epidemics or pandemics; and catastrophic events, including, but not limited to, war, extreme weather events, natural disasters, acts of sabotage and other similar events.

Producing and refining oil, bitumen and diluted bitumen requires high levels of investment and involves particular risks and uncertainties. Our oil sands operations are susceptible to reduced production, slowdowns, shutdowns, or restrictions on our ability to produce higher value products due to the interdependence of our component systems. Delineation of the resources, the costs associated with production, including drilling wells for SAGD operations, and the costs associated with refining oil can entail significant capital outlays. The operating costs associated with oil production are largely fixed in the short-term and, as a result, operating costs per unit are largely dependent on levels of production.

We do not insure against all potential occurrences and disruptions in respect of our assets or operations, and it cannot be guaranteed that our insurance coverage will be available or sufficient to fully cover any claims that may arise from such occurrences or disruptions. Our operations could also be interrupted by natural disasters or other events beyond our control. The occurrence of an event that is not fully covered by our insurance program could have a material adverse effect on our business, financial condition, results of operation and cash flows.

Reserves Replacement and Reserve Estimates

If we fail to acquire, develop or find additional crude oil and natural gas reserves, our reserves and production will decline materially from their current levels. Our financial condition, results of operations and cash flows are highly dependent upon successfully producing from current reserves and acquiring, discovering or developing additional reserves.

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows and revenue derived therefrom are based on a number of variable factors and assumptions including, but not limited to: product prices; future operating and capital costs; historical production from the properties and the assumed effects of regulation by governmental agencies, including royalty payments and taxes, and environmental and emissions related regulations and taxes; initial production rates; production decline rates; and the availability, proximity and capacity of oil and gas gathering systems, pipelines, rail transportation and processing facilities, all of which may cause actual results to vary materially from estimated results.

All such estimates are to some degree uncertain and classifications of reserves are only attempting to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenue expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves may vary from current estimates and such variances may be material.

Estimates with respect to reserves that may be developed and produced in the future are often based on volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history.

Subsequent evaluation of the same reserves based on production history will result in variations, which may be material, in the estimated reserves.

The production rate of oil and gas properties tends to decline as reserves are depleted while the associated operating costs increase. Maintaining an inventory of developable projects to support future production of crude oil and natural gas depends on, among other things: obtaining and renewing rights to explore, develop and produce oil and natural gas; drilling success; completing long-lead time capital intensive projects on budget and on schedule; and the application of successful exploitation techniques on mature properties. Our business, financial condition, results of operations and cash flows are highly dependent upon successfully producing current reserves and adding additional reserves.

Cost Management

Our operating costs could escalate and become uncompetitive due to inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, higher steam-to-oil ratios in our oil sands operations, and additional government or environmental regulations. Our inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on our financial condition, results of operations and cash flows.

The cost or availability of oil and gas field equipment may adversely affect our ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services and construction materials. These materials and services may not be available when required at reasonable prices. Without compromising safety, overall quality and environmental impacts, we continually develop our approved suppliers base to provide undisrupted access to materials, equipment and services, while maintaining a competitive cost baseline via cost escalation mitigation strategies. A failure to secure equipment necessary to our operations for the expected price, on the expected timeline, or at all, may have an adverse effect on our financial condition, results of operations, and cash flows.

Competition

The Canadian and international energy industry is highly competitive in all aspects, including accessing capital, the exploration for, and the development of, new and existing sources of supply, the acquisition of crude oil and natural gas interests and the refining, distribution and marketing of oil and gas products. We compete with other producers and refiners, some of which may have lower operating costs or greater resources than our company does. Competing producers may develop and implement recovery techniques and technologies which are superior to those we employ. The oil and gas industry also competes with other industries in supplying energy, fuel and related products to consumers, including renewable energy sources which may become more prevalent in the future.

Project Execution

Cenovus manages a variety of oil, natural gas and refining projects across its global portfolio, including the current rebuild of our Superior Refinery. The wide range of risks associated with project development and execution, as well as the commissioning and integration of new facilities with existing assets, can impact the economic viability of the Company's projects. These risks include, but are not limited to: our ability to obtain the necessary environmental and regulatory approvals; our ability to obtain favourable terms or to be granted access within land-use agreements; risks relating to schedule, resources and costs, including the availability and cost of materials, equipment and qualified personnel; the impact of general economic, business and market conditions; the impact of weather conditions; risk related to the accuracy of project cost estimates; our ability to finance capital and expenses; our ability to source or complete strategic transactions; the effect of COVID-19 on project execution and timelines; and the effect of changing government regulation and public expectations in relation to the impacts of oil and gas operations on the environment. The commissioning and integration of new facilities within our existing asset base could cause delays in achieving performance targets and objectives. Failure to manage these risks could have a material adverse effect on our financial condition, results of operations and cash flows and may affect our safety and environmental record thereby negatively affecting our reputation and social license to operate.

Partner Risks

Some of our assets are not operated or controlled by us or are held in partnership with others, including through joint ventures. Therefore, our results of operations and cash flows may be affected by the actions of third-party operators or partners and our ability to control and manage risks may be reduced. We rely on the judgment and operating expertise of our partners in respect of the operation of such assets and to provide information on the status of such assets and related results of operations; however, we are, at times, dependent upon our partners for the successful execution of various projects.

Our partners may have objectives and interests that do not align with or may conflict with our interests. No assurance can be provided that the future demands or expectations of Cenovus relating to such assets will be satisfactorily met in a timely manner or at all. If a dispute with a partner or partners were to occur over the development and operation of a project or if a partner or partners were unable to fund their contractual share of the capital expenditures, a project could be delayed and Cenovus could be partially or totally liable for its partner's share of the project.

SAGD Technology

Current technologies used for the recovery of bitumen can be energy intensive, including SAGD which requires significant consumption of natural gas in the production of steam used in the recovery process. The amount of steam required in the production process varies and therefore impacts costs. The performance of the reservoir can also affect the timing and levels of production using SAGD technology. A large increase in recovery costs could cause certain projects that rely on SAGD technology to become uneconomical, which could have a negative effect on our business, financial condition, results of operations and cash flows. There are risks associated with growth and other capital projects that rely largely or partly on new technologies, the incorporation of such technologies into new or existing operations and acceptance of new technologies in the market. The success of projects incorporating new technologies cannot be assured.

Information Systems

We rely heavily on information technology, such as computer hardware and software systems, to properly operate our business. In the event we are unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure, and take other steps to maintain or improve the efficiency and efficacy of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data.

In the ordinary course of business, we collect, use and store sensitive data, including intellectual property, proprietary business information and personal information of our employees and third parties. Despite our security measures, our information systems, technology and infrastructure may be vulnerable to attacks by hackers and/or cyberterrorists or breaches due to employee error, malfeasance or other disruptions, including natural disasters and acts of war. Any such breach could compromise information used or stored on our systems and/or networks and result in the loss, theft or exposure of confidential information related to retail credit card information, personnel files, exploration activities, corporate actions, executive officer communications and financial results. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, operational disruption, site shut-down, leaks or other negative consequences, including damage to our reputation, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

There is also a risk of cyber-related fraud whereby perpetrators attempt to take control of electronic communications or attempt to impersonate internal personnel or business partners to divert payments and financial assets to accounts controlled by the perpetrators. If a perpetrator is successful in bypassing Cenovus's cyber-security measures and business process controls, such cyber-related fraud could result in financial losses, remediation and recovery costs, and an adverse reputational impact.

Security and Terrorist Threats

Security threats and terrorist or activist activities may impact our personnel, which could result in injury, death, extortion, hostage situations and/or kidnapping, including unlawful confinement. A security threat, terrorist attack or activist incident targeted at a facility, terminal, pipeline, rail network, office or offshore vessel/installation owned or operated by Cenovus or any of our partners could result in the interruption or cessation of key elements of our operations. Outcomes of such incidents could have a material adverse effect on our results of operations, financial condition and business strategy. The risk to employees and board members due to ongoing social unrest in Hong Kong is being managed through reduced travel and increased awareness and monitoring of the situation. The potential for detention and/or incarceration of our employees/contractors entering or working in China remains, and as a result, review and reconsideration for travel into China has become a business/corporate process.

Leadership and Talent

Our success is dependent upon our Management, our leadership capabilities and the quality and competency of our talent. If we are unable to retain key personnel and critical talent or to attract and retain new talent with the necessary leadership, professional and technical competencies, it could have a material adverse effect on our financial condition, results of operations and pace of growth.

Litigation

From time to time, we may be the subject of demands, disputes and litigation arising out of our operations. Claims under such litigation may be material or may be indeterminate. Various types of claims may be made including, without limitation, failure to comply with applicable laws and regulations, environmental damages, breach of contract, negligence, product liability, antitrust, bribery and other forms of corruption, tax, securities class actions, derivative actions, patent infringement and employment-related matters. We may be required to incur significant expenses or devote significant resources in defense against any such litigation, which could result in an unfavourable decision, including fines, sanctions, monetary damages, temporary suspensions of operations, or the inability to engage in certain operations or transactions. The outcome of such claims can be difficult to assess or quantify and may have a material adverse effect on our reputation, financial condition and results of operations. In addition, we may be subject to or impacted by climate change related litigation. See "Climate Change Related Litigation" for discussion.

Indigenous Land and Rights Claims

Opposition by Indigenous groups to conduct our operations, development or exploratory activities in any of the jurisdictions in which we conduct business may negatively impact us in terms of public perception, diversion of Management's time and resources, legal and other advisory expenses, and could adversely impact our progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty, title and rights to portions of Canada. There are outstanding Indigenous and treaty rights claims, which may include Indigenous title claims, on lands where we operate, and such claims, if successful, could have a material adverse impact on our operations or pace of growth. No certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect our ability to, or increase the timeline to, obtain or renew, permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals. In addition, the federal government has introduced legislation to implement the *United Nations Declaration on the Rights of Indigenous Peoples* ("UNDRIP"). Other Canadian jurisdictions have also introduced or passed similar legislation, or begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government is uncertain; additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

Regulatory Risk

The oil and gas industry and refining industry in general and our operations in particular are subject to regulation and intervention under federal, provincial, territorial, state and municipal legislation in the countries in which we conduct operations, development or exploratory activities in matters such as, but not limited to: land tenure; permitting of production projects; royalties; taxes (including income taxes); government fees; production rates; environmental protection controls; protection of certain species or lands; provincial and federal land use designations; the reduction of greenhouse gases ("GHGs") and other emissions; the export of crude oil, natural gas and other products; the transportation of crude-by-rail or marine transport; the awarding or acquisition of exploration and production, oil sands or other interests; the imposition of specific drilling obligations; control over the development, abandonment and reclamation of fields (including restrictions on production) and/or facilities; and possibly expropriation or cancellation of contract rights. The implementation of new regulations or the modification of existing regulations could impact our existing and planned projects or increase capital investment, operating expenses or compliance costs, which could adversely impact our financial condition, results of operations and cash flows.

Regulatory Approvals

Our operations require us to obtain approvals from various regulatory authorities and there are no guarantees that we will be able to obtain all necessary licences, permits and other approvals that may be required to carry out certain exploration, development and operating activities on our properties. In addition, obtaining certain approvals from regulatory authorities can involve, among other things, stakeholder and Indigenous consultation, environmental impact assessments and public hearings. Regulatory approvals obtained may be subject to the satisfaction of certain conditions including, but not limited to: security deposit obligations; ongoing regulatory oversight of projects; mitigating or avoiding project impacts; environmental and habitat assessments; and other commitments or obligations. Failure to obtain applicable regulatory approvals or satisfy any of the conditions thereto on a timely basis on satisfactory terms could result in delays, abandonment or restructuring of projects and increased costs.

Abandonment and Reclamation Cost Risk

Cenovus is subject to oil and gas asset abandonment, reclamation and remediation ("A&R") liabilities for our operations, development and exploratory activities, including those imposed by regulation under federal, provincial, territorial, state and municipal legislation in the countries in which we conduct operations, development or exploratory activities.

In Alberta, the A&R liability regime includes the Orphan Well Fund, which is administered by the Orphan Well Association (the "OWA"). The OWA administers orphaned assets and is funded through a levy imposed on licensees, including Cenovus, based on their proportionate share of deemed A&R liabilities for oil and gas facilities, wells and unreclaimed sites in Alberta. The aggregate value of the A&R liabilities assumed by the OWA has increased in recent years and will remain at elevated levels until a significant number of orphaned wells are decommissioned by the OWA. In June of 2020, the OWA's powers were expanded to more effectively manage and accelerate the clean-up of orphaned wells and associated infrastructure. For instance, in certain circumstances the OWA would be allowed to act as an operator and take over production of abandoned wells. While the Alberta Energy Regulator's ("AER's") Site Rehabilitation Program is funding up to $1 billion of eligible abandonment and reclamation projects through December 31, 2022, it is uncertain how this program, or the recent expansion of the OWA's capabilities, will impact future orphan well liabilities being placed on the OWA. The OWA may seek additional funding for such liabilities from industry participants, including Cenovus.

The AER has broad discretion relating to liability management ratings, licence eligibility and licence transfers. Permit holders that are considered high risk and/or have relatively high levels of A&R obligations within their asset bases, may be negatively affected by increased financial requirements, including potential counterparties to Cenovus. This may result in future insolvencies and additional orphaned assets. In addition, this may impact Cenovus's ability to transfer our licences, approvals or permits, and may result in increased costs and delays or require changes to or abandonment of projects and transactions.

Cenovus has an ongoing environmental monitoring program at owned and leased retail locations and performs remediation where required. The costs of such remediation depend on a number of uncertain factors such as the extent and type of remediation required. Due to uncertainties inherent in the estimation process, it is possible that existing estimates may need to be revised and that conditions may exist at various retail locations that require future expenditures. Such future costs may not be determinable due to the unknown timing and extent of corrective actions that may be required.

For Offshore, the present value cost for decommissioning and abandonment of the offshore wells and facilities is estimated based on known regulations, procedures and costs today for undertaking the decommissioning, the majority of which is projected to be incurred in the 2030s. It is possible that these costs may change materially before decommissioning due to regulatory changes, technological changes, acceleration of decommissioning timelines, and inflation among other variables.

While the impact on Cenovus of any legislative, regulatory or policy decisions relating to the A&R liability regulatory regime in the jurisdictions in which we conduct operations, development or exploratory activities cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact Cenovus and materially and adversely affect, among other things, our business, financial condition, results of operations and cash flows.

Royalty Regimes

Our cash flows may be directly affected by changes to royalty regimes. The governments of the jurisdictions where we have producing assets receive royalties on the production of hydrocarbons from lands in which they respectively own the mineral rights and which Cenovus produces under agreement with each respective government. Government regulation of royalties is subject to change for a number of reasons, including, among other things, political factors. In Canada, there are certain provincial mineral taxes payable on hydrocarbon production from lands other than Crown lands. The potential for changes in the royalty and mineral tax regimes applicable in the jurisdictions in which Cenovus operates, or changes to how existing royalty regimes are interpreted and applied by the applicable governments, creates uncertainty relating to the ability to accurately estimate future royalty rates or mineral taxes and could have a significant impact on our business, financial condition, results of operations and cash flows. An increase in the royalty rates or mineral taxes in jurisdictions where we have producing assets would reduce our earnings and could make, in the respective jurisdiction, future capital expenditures or existing operations uneconomic. A material increase in royalties or mineral taxes may reduce the value of our associated assets.

Canada-United States-Mexico Agreement ("CUSMA")

On July 1, 2020, the new CUSMA entered into force, replacing the North American Free Trade Agreement ("NAFTA"). According to a Government of Canada technical summary of negotiated outcomes related to the energy sector, under CUSMA, the rule of origin applicable to heavy oil containing diluent has been relaxed to allow up to 40 percent of non-originating diluent that is added for the purpose of transportation in pipelines without affecting the originating status of the product, which will allow Canadian products to more easily qualify for duty-free treatment when imported into the U.S. The related CUSMA side letter on energy between Canada and the U.S. also promotes regulatory transparency and non-discrimination in access to or use of energy infrastructure, which may potentially benefit the Canadian heavy oil industry. While it is not yet known how certifications can be successfully substantiated, this is an improvement to the NAFTA origin rule.

The investor-state dispute settlement provisions will no longer be available to protect future investments of Canadians in the U.S. or U.S. investments in Canada. For three years after the termination of NAFTA, existing "legacy investments" will maintain their access to the investor-state dispute settlement under NAFTA Chapter 11.

Labour Risk

Cenovus depends on unionized labour for the operation of certain facilities and may be subject to adverse employee relations and labour disputes, which may disrupt operations at such facilities. As of February 1, 2021, approximately 6.1 percent of our employees were represented by unions under existing collective bargaining agreements with Cenovus's newly acquired operating subsidiaries. We cannot assure that strikes or work stoppages will not occur. Any prolonged work stoppages may have a material adverse effect on our business, reputation, financial condition, results of operations and cash flows.

In addition, we may not be able to renew or renegotiate our subsidiaries' collective bargaining agreements on satisfactory terms or at all and a failure to do so may increase our costs. Moreover, employees who are not currently represented by unions may seek union representation in the future and efforts may be made from time to time to unionize other portions of our workforce. Any renegotiation of our existing collective bargaining agreements may result in terms that are less favourable to Cenovus, which may materially and adversely affect our financial condition, results of operations and cash flows.

Future unionization efforts or changes in legislation and regulations may result in labour shortages, higher labour costs, as well as wage, benefit, and other employment consequences, especially during critical maintenance and construction periods, all of which may increase our costs, reduce our revenues or limit our operational flexibility.

International Developments and Geopolitical Risk

Cenovus's business includes Asia Pacific Assets in the South China Sea and the Madura Strait offshore Indonesia, and includes cooperation agreements with China National Offshore Oil Corporation or its subsidiaries (collectively "CNOOC"), which also operates certain of these assets.

As a result, Cenovus is exposed to the financial and operational risks associated with uncertain international relations. Political developments impacting international trade, including trade disputes and increased tariffs, particularly between the U.S. and China and Canada and China, may negatively impact markets and cause weaker macroeconomic conditions or drive political or national sentiment, weakening demand for crude oil, natural gas and refined products. For example, U.S. government trade policy has resulted in, and could result in more, U.S. trading partners adopting responsive trade policy and may make it more difficult or costly for Cenovus to operate in and export our products to those countries.

Moreover, our operations may be materially adversely affected by political, economic or social instability or events, including the renegotiation or nullification of agreements and treaties, the imposition of onerous regulations, embargoes, sanctions, and fiscal policy, changes in laws governing existing operations, financial constraints, including currency restrictions and exchange rate fluctuations, unreasonable taxation and the behaviour of international public officials, joint venture partners or third-party representatives. Specifically, our Asia Pacific assets expose Cenovus to the effects of the changing U.S.-China and Canada-China relations, including escalating tensions and possible retaliations. It is possible that additional actions taken by the U.S. and Canada may limit or restrict foreign companies' ability to participate in projects and operate in certain sectors of the Chinese economy, including the energy sector.

On November 12, 2020, the former President of the United States signed an executive order prohibiting U.S. persons from engaging in transactions in the publicly traded securities of specified companies with alleged ties to the Chinese military. The prohibition is intended to be effective from January 11, 2021 to November 21, 2021. On December 3, 2020, CNOOC was added to the list of companies with alleged ties to the Chinese military. Although the executive order does not limit Cenovus's offshore operations in Asia, further U.S. sanctions against CNOOC may affect such operations, depending on the nature of such sanctions.

A new U.S. presidential administration took office in January 2021 and may implement domestic and foreign policy that could have a significant impact on Cenovus's financial condition or results of operations. We cannot accurately predict the implementation of U.S. or Canadian policy affecting any current or future activities by CNOOC, Cenovus's other international partners or Cenovus. Similarly, we cannot accurately predict whether U.S. restrictions will be further tightened or the impact of government action on Cenovus's offshore operations in Asia. It is possible that the U.S. or Canadian government may subject CNOOC or Cenovus's other international partners to restrictions or sanctions, which may adversely impact our offshore operations in Asia.

Moreover, it is possible that our partnership with CNOOC may deter certain investors from investing in Cenovus, or encourage certain investors to divest their existing holdings in Cenovus, which could have a negative impact on our share price and our ability to raise capital. It is also possible that as a result of our partnership with CNOOC, we may be subject to negative media attention which may affect investors' perception of Cenovus in Canada, the U.S. and globally, and which may negatively affect our share price.

In addition, Cenovus may be affected by changes to bilateral relationships, the frameworks and global norms that govern international trade, and other geopolitical developments. This includes acute shocks (such as civil unrest or sanctions) and chronic stresses (such as political or business disputes and other forms of conflict, including military conflict) that may pose longer-term threats to our business. Unilateral action by, or changes in relations between, countries in which we operate, including the U.S. and China, and such countries' approach to multilateralism and trade protectionism can impact our ability to access markets, technology, talent and capital. Disruptions or unanticipated changes of this nature may affect our ability to sell our products for optimum value or access inputs required for effective operations and has the potential to adversely affect our financial performance.

Geopolitical events, such as a shift in the relationship, an escalation or imposition of sanctions, tariffs or other trade tensions between the U.S. and China and Canada and China, may affect the supply, demand and price of crude oil, natural gas and refined products and therefore our financial performance. The timing, extent and fallout of the ongoing tensions between the U.S. and China and Canada and China remains uncertain and the impact on our business is unknown.

Shifts in global power relations may also introduce greater uncertainty with respect to issues requiring global co-ordination (such as climate change, trade agreements, tax regulation, freedom of navigation and technology regulation), as well as raise questions on the efficacy of and trust in international institutions, including those that underpin international trade. These types of changes may cause restrictions or impose costs on our business, and may inhibit our future opportunities or affect our financial condition.

Cenovus's financial performance, operations and business may be adversely affected by any of the foregoing risks associated with international relations and specifically those risks arising from evolving U.S.-China and Canada-China relations. The nature, extent and magnitude of the effect of dynamic trade relations on Cenovus cannot be accurately predicted and may have a material adverse impact on our business, prospects, financial condition, results of operations, cash flows, and reputation.

Climate-Related Risks

There is growing international concern regarding climate change and there has been a significant increase in focus on the timing and pace of the transition to a lower-carbon economy. Governments, financial institutions, insurance companies, environmental and governance organizations, institutional investors, social and environmental activists, and individuals, are increasingly seeking to implement, among other things, regulatory and policy changes, changes in investment patterns, and modifications in energy consumption habits and trends which, individually and collectively are intended to or have the effect of accelerating the reduction in the global consumption of carbon-based energy, the conversion of energy usage to less carbon-intensive forms and the general migration of energy usage away from carbon-based forms of energy.

Climate change and its associated impacts may increase our exposure to, and magnitude of, each of the risks identified in the Risk Management and Risk Factors section of this MD&A. Overall, Cenovus is not able to estimate at this time the degree to which climate change related regulatory, climatic conditions, and climate-related transition risks could impact the Company’s financial and operating results. Our business, financial condition, results of operations, cash flows, reputation, access to capital, access to insurance, 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 climate change and its associated impacts.

Transition Risks – Policy & Legal

Climate Change Regulation

Cenovus operates in several jurisdictions that regulate or have proposed to regulate air pollutants, including GHG emissions. Some of these regulations are in effect while others remain in various phases of review, discussion or implementation. Uncertainties exist relating to the timing and effects of these emerging regulations, other contemplated legislation, including how they may be harmonized, making it difficult to accurately determine the cost impacts and effects on our suppliers. Additional changes to climate change legislation may adversely affect our business, financial condition, results of operations and cash flows, which cannot be reliably or accurately estimated at this time. In December 2020, the Government of Canada proposed increasing the carbon tax to $170/tonne carbon dioxide equivalent (“CO2e”) by 2030. To reach that level, the price imposed on carbon will rise from the 2022 rate of $50/tonne CO2e by $15/tonne CO2e each year until 2030. If made into law, this may have a significant impact on Cenovus. Notably, several Canadian provinces have launched constitutional challenges to Canada's national carbon-pricing regime that were heard by the Supreme Court of Canada ("SCC") in September 2020; however, as of December 31, 2020, the SCC's decision had not yet been issued. To the extent a province's carbon pricing system does not meet the federal stringency requirements, the federal "backstop" price of carbon applies. As of December 2020, the federal backstop applied in Alberta, Manitoba, New Brunswick, Ontario and to electricity generation and natural gas transmission pipelines in Saskatchewan.

In Alberta, facilities emitting over 100,000 tonnes of GHG emissions annually are subject to the *Technology Innovation and Emissions Reductions Regulation* (“TIER”), which is considered equivalent to the federal carbon-pricing system for 2020. Facilities also have the choice to opt in to TIER, thereby avoiding the federal fuel charge.

The Government of Canada is also committed to reducing methane emissions from the crude oil and natural gas sector by 40-45 percent from 2012 levels by 2025. Regulatory requirements for fugitive equipment leaks and venting from well completion and compressors came into force on January 1, 2020. Further restrictions on facility production venting restrictions and venting limits for pneumatic equipment come into force on January 1, 2023. Provinces may introduce provincial regulations, and if found to be at least equivalent with the federal scheme, shall be enabled through a federal equivalency agreement process. Alberta, British Columbia and Saskatchewan have such equivalency agreements in place.

The U.S. does not have federal legislation establishing targets for the reduction of, or limits on, GHG emissions. However, the federal Environmental Protection Agency (“EPA”) has and may continue to promulgate regulations concerning the reporting and control of GHG emissions. Since 2010, the EPA’s Greenhouse Gas Reporting Program (“GHGRP”) requires any facility releasing more than 25,000 tonnes of CO2e emissions per year to report those emissions on an annual basis. In addition to reporting direct CO2e emissions, the GHGRP requires refineries to estimate the CO2e emissions from the potential subsequent combustion of the refinery's products. The Biden Administration has indicated that it will rejoin the Paris Agreement and seek to implement its objectives with respect to GHG emissions, including short-term global emissions reductions and net-zero global emissions by mid-century, and that it will begin the process of developing U.S. emission reduction targets under the Paris Agreement. It is too early to assess what impact these actions may have on our business, financial condition or results of operations.

Negative consequences which could arise as a result of changes to the current regulatory environment include, but are not limited to, changes in environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, potentially increasing the cost of construction, operation and abandonment. Other possible effects from emerging regulations may also include, but are not limited to: increased compliance costs; permitting delays; and substantial costs to generate or purchase emission credits or allowances, all of which may increase operating expenses. Further, emission allowances or offset credits may not be available for acquisition or may not be available on an economic basis, required emissions reductions may not be technically or economically feasible to implement, in whole or in part, and failure to have access to resources or technology to meet emissions reduction requirements or other compliance mechanisms may have a material adverse effect on our business resulting in, among other things, fines, permitting delays, penalties and the suspension of operations.

The extent and magnitude of any adverse impacts of current or additional programs or regulations beyond reasonably foreseeable requirements cannot be reliably or accurately estimated at this time, in part because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the timeframes for compliance. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to Cenovus.

Low Carbon Fuel Standards

Existing and proposed environmental legislation and regulation developed by certain U.S. states, Canadian provinces, the Canadian federal government and members of the European Union, regulating carbon fuel standards could result in increased costs and reduced revenue for Cenovus. The potential regulation may negatively affect the marketing of Cenovus's bitumen, crude oil or refined products, and may require us to purchase emissions credits in order to affect sales in such jurisdictions.

Environment and Climate Change Canada published a proposed regulatory framework in 2017 for the Clean Fuel Standard under the *Canadian Environmental Protection Act, 1999*, followed by a Regulatory Design Paper in December 2018 and a Proposed Regulatory Approach in June 2019. The proposed regulations for the Clean Fuel Standard were published in December 2020 and final regulations are planned to be published in late 2021, with new regulations under the Clean Fuel Standard targeted to come into force in 2022. The federal government has indicated that over time, the new Clean Fuel Standard would replace the current Renewable Fuels Regulations, which currently require producers and importers of gasoline, diesel fuel and heating distillate to acquire a certain number of renewable fuel compliance units commensurate with the volumes of fuel they produce or import. The proposed new regulatory framework would impose lifecycle carbon intensity requirements for certain liquid fuels and establish rules relating to the trading of compliance credits. Carbon intensity requirements under the Clean Fuel Standard regulation would become more stringent over time and would be differentiated between different types of renewable fuels to reflect the associated emissions reduction potential. Regulated parties, which may include fuel producers and importers, would have some flexibility with respect to how to achieve lower carbon fuels in Canada.

The Clean Fuel Standard regulation has the potential to impact our business, financial condition, results of operations and cash flows, though at this time it is difficult to predict or quantify any such impacts.

Renewable Fuel Standards

Our U.S. refining operations are subject to various laws and regulations that impose stringent and costly requirements. The Environmental Protection Agency has implemented the Renewable Fuel Standard program that mandates that a certain volume of renewable fuel replace or reduce the quantity of certain petroleum-based transportation fuels sold or introduced in the U.S. Obligated Parties, including refiners or importers of gasoline or diesel fuel, achieve compliance with targets set by the U.S. Environmental Protection Agency by blending certain types of renewable fuel into transportation fuel, or by purchasing RINs from other parties on the open market. The mandate requires the volume of renewable fuels blended into finished petroleum products to increase over time until 2022. A RIN is a number assigned to each gallon of renewable fuel produced or imported into the U.S. RINs were implemented to provide refiners with flexibility in complying with the renewable fuel standards.

Cenovus and its refinery operating partners comply with the U.S. Renewable Fuel Standard by blending renewable fuels manufactured by third parties and by purchasing RINs on the open market, where prices fluctuate. The Company cannot predict the future prices of RINs and renewable fuel blendstocks, and the costs to obtain the necessary RINs and blendstocks could be material. The Company's financial position, results of operations and cash flows may be materially impacted if we are required to pay significantly higher prices for RINs or blendstocks to comply with the RFS mandated standards and are unable to pass the compliance costs on to our customers.

Climate Change Related Litigation

In recent years there has been an increase in climate change related demands, disputes, and litigation in various jurisdictions including the U.S. and Canada, asserting various claims, including that energy producers contribute to climate change, that such entities are not reasonably managing business risks associated with climate change, and that such entities have not adequately disclosed business risks of climate change. While many of the climate change related actions are in preliminary stages of litigation, and in some cases assert novel or untested causes of action, there can be no assurance that legal, societal, scientific and political developments will not increase the likelihood of successful climate change related litigation against energy producers, including Cenovus. The outcome of any such litigation is uncertain and may materially impact our financial condition or results of operations. Moreover, unfavourable outcomes or settlements of litigation could encourage the commencement of additional litigation. We may also be subject to adverse publicity associated with such matters, which may negatively affect public perception and our reputation, regardless of whether we are ultimately found responsible. We may be required to incur significant expenses or devote significant resources in defense against any such litigation.

Transition Risks – Market

Demand and Commodity Prices

The recent increase in focus on the timing and pace of the transition to a lower-carbon economy and resulting trends will likely affect global energy demand and usage, including the composition of the types of energy generally used by industry and individual consumers. However it is not currently possible to predict the timelines for and precise effects of this transition to a potential lower-carbon economy, which will depend on a multitude of factors including the ability to develop adequate replacement sources of energy, technology development and adaptation including in the area of transportation electrification, the ability to conceptualize, develop and commercialize technologies for the production, storage and distribution of adequate supplies of alternative energy, consumption patterns, global growth and industrial activity, in order to predict the longer-term demand trends for carbon-based energy sources. All of these factors are beyond our control and could result in a high degree of price volatility for each of crude oil, natural gas and refined products.

Access to Capital and Insurance

Capital markets are adjusting to the risks that climate change poses and as a result, our ability to access capital and secure necessary or prudent insurance coverage may also be adversely affected in the event that institutional investors, credit rating agencies, lenders and/or insurers adopt more restrictive decarbonization policies. Certain insurance companies have taken actions or announced policies to limit available coverage for companies which derive some or all of their revenue from the oil sands sector. As a result of these policies, premiums and deductibles for some or all of our insurance policies could increase substantially. In some instances, coverage may be reduced or become unavailable. As a result, we may not be able to renew our existing policies, or procure other desirable insurance coverage, either on commercially reasonable terms, or at all. The future development of our business may be dependent upon our ability to obtain additional capital, including debt and equity financing.

Transition Risks – Reputation

Reputation and Public Perception of Alberta Oil Sands

Development of the Alberta oil sands has received considerable attention on the subjects of environmental impact, climate change, GHG emissions and Indigenous engagement. Concerns about oil sands may, directly or indirectly, impair the profitability of our current oil sands projects, and the viability of future oil sands projects, by creating significant regulatory, economic and operating uncertainty. Increased public opposition to the oil sands industry could lead to constrained access to insurance, liquidity and capital and changes in demand for Cenovus's products, which may impact revenue.

For example, legislation or policies that limit the purchase of crude oil or bitumen produced from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for this crude oil, reduce its price and may result in stranded assets or an inability to further develop oil resources.

Climate Change – Physical Risks

Extreme climatic conditions may also have material adverse effects on Cenovus's financial condition and results of operations. Weather and climate affect demand, and therefore, the predictability of the demand for energy is affected to a large degree by the predictability of weather and climate. In addition, Cenovus's exploration, production and construction operations, and the operations of major customers and suppliers, can be affected by floods, forest fires, earthquakes, hurricanes, and other extreme weather events. This may result in cessation or diminishment of production, delay of exploration and development activities or delay of plant construction.

Cenovus operates in some of the harshest environments in the world, including offshore Newfoundland and Labrador. Climate change may increase the frequency of severe weather conditions in these locations including winds, flooding and variable temperatures, which are contributing to the melting of northern ice and increased creation of icebergs. Icebergs off the coast of Newfoundland and Labrador may threaten Atlantic oil production facilities, cause spills, damage assets, disrupt production or have human impacts.

Our other crude oil and natural gas production activities are also subject to chronic physical risks such as a shorter timeframe for our winter drilling program, changes in the water table and reduced access to water due to drought conditions. A systemic change in temperature or precipitation patterns could result in more challenging conditions for the construction of ice roads, execution of our winter drilling program and reclamation activities and could reduce the availability of water due to the increasing likelihood of drought conditions.

Environmental Risk

All phases of crude oil, natural gas and refining operations are subject to environmental regulation pursuant to a variety of federal, provincial, territorial, state and municipal laws and regulations in the jurisdictions in which we operate (collectively, the "environmental regulations"). Environmental regulations provide that wells, facility sites, refineries and other properties and practices associated with our operations be constructed, operated, maintained, abandoned, reclaimed and undertaken in accordance with the requirements set out therein. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications.

Cenovus anticipates that further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liabilities, the introduction of emissions limits, increased compliance costs and approval delays for critical licences and permits. The complexities of changes in environmental regulations make it difficult to predict the potential future impact to Cenovus.

Compliance with environmental regulations requires significant expenditures. Our future capital expenditures and operating expenses could continue to increase as a result of, among other things, developments in our business, operations, plans and objectives and changes to existing, or implementation of new, environmental regulations. Failure to comply with environmental regulations may result in, among other things, the imposition of fines, penalties, environmental protection orders, suspension of operations, and could adversely affect our reputation. The costs of complying with environmental regulations may have a material adverse effect on our business, financial condition, results of operations and cash flows. The implementation of new environmental regulations or the modification of existing environmental regulations affecting the crude oil and natural gas industry generally could reduce demand for crude oil and natural gas as well as shift hydrocarbon demand toward relatively lower carbon sources, increase compliance costs, lengthen project implementation times, and have an adverse effect on our business, financial condition, results of operations and cash flows.

Canadian Species at Risk Act

The Canadian federal *Species at Risk Act,* as well as provincial regulation regarding threatened or endangered species and their habitat may limit the pace and the amount of development or activity in areas identified as critical habitat for species of concern, such as woodland caribou. Recent petitions and litigation against the federal government in relation to their obligations under the *Species at Risk Act* have raised issues associated with the protection of species at risk and their critical habitat both federally and on a provincial level. In Alberta, a suite of initiatives have been undertaken to support caribou recovery, including the Draft Provincial Woodland Caribou Range Plan, which was released in 2017 but has not yet been finalized. Other initiatives include negotiation of conservation agreements under Section 11 of the *Species at Risk Act* (which codifies concrete measures to support the conservation of the species and the protection of its critical habitat), and the elaboration of sub-regional plans for the Cold Lake, Bistcho and Upper Smokey areas, to address recovery outcomes for certain caribou ranges. If plans and actions undertaken by the provinces are deemed insufficient to support caribou recovery, the federal legislation includes the ability to implement measures that would preclude further development or modify existing operations. The extent and magnitude of any potential adverse impacts of legislation on in situ oil sands project development and operations cannot be estimated, as uncertainty exists as to whether plans and actions undertaken by the provinces will be sufficient to support caribou recovery.

Canadian Federal Air Quality Management System

The Multi Sector Air Pollutants Regulations ("MSAPR"), issued under the *Canadian Environmental Protection Act, 1999*, seek to protect the environment and health of Canadians by setting mandatory, nationally-consistent air pollutant emission standards. The MSAPR are aimed at equipment-specific Base-Level Industrial Emissions Requirements ("BLIERs"). Nitrogen oxide BLIERs from our non-utility boilers, heaters and stationary engines are regulated in accordance with specified performance standards. We anticipate that the MSAPR will result in adverse impacts to Cenovus including but not limited to capital investment required to retrofit existing equipment and increased operating costs.

Canadian Ambient Air Quality Standards ("CAAQS") for nitrogen dioxide, sulphur dioxide, fine particulate matter and ozone were introduced as part of a national Air Quality Management System. Provinces may implement the CAAQS at the regional air zone level and air zone management actions may include more stringent emissions standards applicable to industrial sources from approval holders in regions where Cenovus operates that may result in adverse impacts including but not limited to capital investment related to retrofit existing facilities and increased operating costs.

Review of Environmental and Regulatory Processes

Increased environmental assessment obligations imposed by federal, provincial, territorial, state and municipal governments in the jurisdictions in which we conduct operations, development or exploratory activities may create risk of increased costs and project development delays. The extent and magnitude of any adverse impacts of changes to the legislation or policies on project development and operations cannot be estimated at this time.

The Canadian federal Bill C-69, an Act to enact the *Impact Assessment Act and* the *Canadian Energy Regulator Act,* to amend *the Navigation Protection Act (*renamed the *Canadian Navigable Water Act)* and to make consequential amendments to other Acts came into force in August 2019. In addition, Bill C-68, which amended the *Fisheries Act,* came into force at the same time.

The *Fisheries Act* amendments restored the previous prohibition against "harmful alteration, disruption or destruction of fish habitat" and the prohibition against causing the death of fish by means other than fishing and introduced several new requirements expanding the scope of protection and role of Indigenous groups and interests. These prohibitions may result in increased permitting requirements and time to obtain permits where Cenovus's operations potentially impact fish or fish habitat.

The *Canadian Navigable Waters Act* expanded its scope to all navigable waters, created greater oversight for navigable waters, and introduced requirements expanding the scope of protection and the role of Indigenous groups and interests. The broader application of the *Canadian Navigable Waters Act* may result in increased permitting requirements and time to obtain permits where Cenovus's operations potentially impact navigable waters.

The *Impact Assessment Act* ("IAA") established the Impact Assessment Agency of Canada, which leads and coordinates impact assessments for all designated projects. The IAA expands the assessment considerations beyond the environment to expressly include health, economic, social, and gender impacts, as well as considerations related to sustainability and Canada's climate change commitments.

Of note, the revised Project List outlined in the *Physical Activities Regulations* under the IAA captures in situ oil sands facilities with a bitumen production capacity of 2,000 m^3/day or more, and expansions of existing in situ oil sands facilities if the expansion would result in an increase in bitumen production capacity of 50 percent or more and a total bitumen production capacity of 2,000 m^3/day or more, but provides an exemption for a project proposed within a province in which there is a legislated limit on GHG emissions produced by the oil sands sector. For as long as the provincial government maintains the cap on oil sands emissions in Alberta and the cap has not been reached, Cenovus's in situ oil sands projects should be exempted from the application of the new federal impact assessment system, provided the above-noted conditions are met. However, other types of projects would undergo a federal assessment.

Water Licences

Cenovus utilizes fresh water in certain operations, which is obtained under licenses issued within each respective jurisdiction's regulations. If water use fees increase or a change under these licences reduces the amount of water available for our use, production could decline or operating expenses could increase, both of which may have a material adverse effect on our business and financial performance. There can be no assurance that the licences to withdraw water will not be rescinded or that additional conditions will not be added to these licences. There is no assurance that if we require new licences or amendments to existing licences, that these licences or amendments will be granted on favourable terms. This may adversely affect our business, including the ability to operate our assets and execute development plans.

Hydraulic Fracturing

Certain stakeholders have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources and suggest that additional federal, provincial, state, territorial and/or municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process.

In addition, some areas of British Columbia and Alberta are experiencing increasing localized frequency of seismic activity which has been associated with oil and gas operations. Although the occurrence of seismicity in relation to oil and gas operations is generally very low, it has been linked to deep disposal of wastewater in the U.S. and has been correlated with hydraulic fracturing in Western Canada, which has prompted legislative and regulatory initiatives intended to address these concerns.

The Canadian federal government and certain provincial governments continue to review certain aspects of the existing scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. The Government of British Columbia released an action plan in 2019 based on the results of its scientific review of hydraulic fracturing and related impacts on water and seismic activity, which contains a number of actions to be implemented in a phased approach that will include increased monitoring, aquifers mapping and improvements to the regulatory regime. In Alberta, the AER has implemented seismic monitoring and reporting requirements for hydraulic fracturing operations in certain zones in some active oil and gas areas of Alberta.

Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to limitations or restrictions to oil and gas development activities, operational delays, increased compliance costs, additional operating requirements, or increased third-party or governmental claims that could increase our cost of doing business as well as reduce the amount of natural gas and oil that Cenovus is ultimately able to produce from its reserves.

Cenovus ESG Focus Areas and Targets

Generally speaking, Cenovus's ESG targets depend significantly on our ability to execute our current business strategy, related milestones and schedules, and to successfully integrate the assets of Cenovus and the assets of Husky, each of which can be impacted by the numerous risks and uncertainties associated with our business and the industry in which we operate, as outlined in the Risk Management and Risk Factors section of this MD&A. We recognize that our ability to adapt to and succeed in a lower-carbon economy will be compared against our peers. Investors and stakeholders increasingly compare companies based on ESG-related performance, including climate-related performance. Failure to achieve our ESG targets, or a perception among key stakeholders that our ESG targets are insufficient, could adversely affect our reputation and our ability to attract capital and insurance coverage.

There is also a risk that some or all of the expected benefits and opportunities of achieving the various ESG targets may fail to materialize, may cost more to achieve or may not occur within the anticipated time periods. In addition, there are risks that the actions taken by Cenovus in implementing targets and ambitions relating to ESG focus areas may have a negative impact on our existing business and operations and increase capital expenditures, which could have a negative impact on our future operating and financial results.

ESG Targets May Change Following Completion of the Arrangement

Completion of the Arrangement between Cenovus and Husky on January 1, 2021 resulted in a combination of the business activities previously carried on separately by each of Husky and Cenovus. Cenovus remains committed to world-class safety performance and ESG leadership following closing of the Arrangement. This includes completing additional analysis to set new ESG targets and ambitions for the combined business.

The ESG targets and ambitions of the combined business may not necessarily be the same as the targets or ambitions previously set by Cenovus. This is dependent, in large measure, on the completion of our review and analysis of the combined business following the completion of the Arrangement to determine whether such targets and ambitions remain appropriate for the combined business. In addition, the integration of Husky and Cenovus will require the dedication of substantial effort, time and resources on the part of management and staff of the combined company, which may divert focus from planned initiatives, including development and implementation of ESG targets and ambitions, towards other operational matters and could result in a disruption to, or delay in, the development and implementation of ESG targets and ambitions for the combined company or a shift in resources to other operational and business strategies.

The below sections include discussion of the ESG targets released by Cenovus in January 2020 which may be subject to change as a result of our determination of whether such targets and ambitions remain appropriate for the combined business.

Greenhouse Gas Emissions and Targets

Cenovus's future results and its ability to respond to and manage transition and physical risks of climate change may depend in part on our ability to adapt and apply our business model to a lower-carbon economy and to lower scope 1 and 2 GHG emissions (see Definitions section of this MD&A). Our ability to lower scope 1 and 2 GHG emissions on both an absolute basis and in terms of intensity in our operations and our long-term ambition of reaching net-zero emissions by 2050, are subject to numerous risks and uncertainties and our actions taken in implementing such targets may also expose us to certain additional and/or heightened financial and operational risks. Furthermore, our long-term ambition of reaching net-zero emissions by 2050 is inherently less certain due to the longer timeframe and certain factors outside of our control, including the commercial application of future technologies that may be necessary for us to achieve this long-term ambition.

A reduction in GHG emissions relies on, among other things, Cenovus's ability to develop, access and implement commercially viable and scalable emission reduction strategies and related technology and products. In addition, there are other operational risks that may hinder our ability to successfully meet our GHG emission targets and goals, including: unexpected impediments to, or effects of, the implementation of cogeneration plants at our Foster Creek and Christina Lake oil sands facilities and other investments in renewables, including in respect of available offsets and the availability and status of credit or offset for cogeneration facilities and other renewables; the effectiveness of air flue exchanges at Foster Creek and Christina Lake; our ability to electrify and otherwise adjust our operations in the Conventional segment; the unavailability of, or limited benefits from, technology that is expected to be commercially viable in the near term and their associated future benefits, including SAGD enhancement technologies, such as solvent-aided process and solvent-driven process technologies, carbon capture, utilization and storage technology and downhole technology improvements; and a failure to capture the anticipated benefits of continued technological development, industry collaboration and innovation to find solutions to reduce costs and GHG emissions intensity. In the event that we are unable to implement these strategies and technologies as planned without negatively impacting our expected operations or cost structure, or such strategies or technologies do not perform as expected, we may be unable to meet our 2050 ambition on the current timelines, or at all.

In addition, achieving our GHG 2050 ambition will require capital expenditures and Company resources, with the potential that expectations regarding the costs required to achieve these targets and ambitions differ from our original estimates and the differences may be material. Furthermore, a shift of expenditures and resources towards such targets and ambition may negatively impact our business and operations. The cost of investing in emissions-intensity reduction technologies, and the resultant change in the deployment of resources and focus, could have a negative impact on our future operating and financial results.

Our GHG emissions targets and ambitions may also be subject to change as a result of Cenovus's determination of whether such targets and ambitions remain appropriate for the combined business.

Indigenous Engagement Target

Cenovus's Indigenous engagement target to spend $1.5 billion with Indigenous owned or operated businesses by the end of 2030 is subject to a number of financial, operational and efficiency risks relating to actions taken in implementing such target.

In addition, a failure or delay in achieving our Indigenous engagement target may adversely affect our relationship with neighboring Indigenous businesses and communities and our broader reputation. If we are unable to maintain a positive relationship with Indigenous communities near our operations, our progress and ability to develop and operate properties in line with our current business and operational strategies may be adversely impacted.

Our Indigenous engagement target may also be subject to change as a result Cenovus's determination of whether such a target remains appropriate for the combined business.

Land and Wildlife Target

Our land and wildlife targets are composed of the reclamation of 1,500 decommissioned well sites and $40 million in spend between 2016 and 2030 to restore more land within caribou ranges than disturbed by Cenovus's activity. Our ability to meet this target is subject to various environmental and regulatory risks, which could impose significant costs, restrictions, liabilities and obligations on Cenovus and limit our capacity to achieve such targets. See Abandonment and Reclamation Cost Risk above.

Financial risks including an increase in operating costs, changes to market conditions and access to additional capital, if needed, could result in our inability to fund, and ultimately meet, our land and wildlife targets on the current timelines, or at all. In addition, the development and implementation of range plans in these areas may have an impact on the pace and amount of development in these areas and could potentially increase costs for restoration or offsetting requirements, which could have a material adverse effect on our business, financial condition, reserves and results of operations. An inability to develop, execute on and complete ongoing reclamation plans and proactively manage our interactions with wildlife may adversely impact Cenovus's progress and ability to explore and develop properties.

Our land and wildlife targets may also be subject to change as a result of Cenovus's determination of whether such targets remain appropriate for the combined business.

Water Stewardship Target

Cenovus's ability to achieve a freshwater intensity of 0.1 barrels of freshwater per barrel of oil equivalent by the end of 2030 will depend on the commercial viability and scalability of relevant water reduction strategies and related steam and water usage technology and products. There are risks associated with relying largely or partly on new technologies, the incorporation of such technologies into new or existing operations and acceptance of new technologies in the market. In the event we are unable to effectively and efficiently deploy the necessary technology, or such strategies or technologies do not perform as expected, achieving our stated target of reducing our water intensity could be interrupted, delayed or abandoned.

Our water stewardship targets may also be subject to change as a result of Cenovus's determination of whether such targets remain appropriate for the combined business.

Reputation Risk

We rely on our reputation to build and maintain positive relationships with investors and other stakeholders, to recruit and retain staff, and to be a credible, trusted company. Any actions we take that influence public or key stakeholder opinions have the potential to impact our reputation which may adversely affect our share price, development plans and our ability to continue operations. There is increasing opposition from activist organizations and the public towards oil sands operations stemming from the perceived impact of the industry on the environment, climate change and GHG emissions. See Reputation and Public Perception of Alberta Oil Sands for further discussion.

Other Risks

Risks Related to the Arrangement

Entry into New Business Activities

Prior to the Arrangement, Cenovus's business was focused on the development and production of bitumen in northeast Alberta, natural gas and NGLs processing in the Conventional segment, and refining, transporting, marketing and selling crude oil, natural gas and NGLs in Canada and the U.S. Husky's business involved upstream development and production in Western Canada, offshore China, Indonesia and Atlantic Canada, and upgrading of heavy oil, refining crude oil, and marketing refined petroleum products in Canada and the U.S. The combined company's business comprises a combination of these businesses, which results in a different business and asset mix than the previous standalone businesses of Cenovus and Husky, respectively. The expansion of Cenovus's activities into new geographic and operational areas as a result of the Arrangement may present additional risks or significantly increase its exposure to one or more of Cenovus's present risk factors. The new business combination may also subject Cenovus to different business risks than those which were previously applicable to Cenovus and Husky as separate entities.

Possible Failure to Realize Anticipated Benefits of the Arrangement

Realizing the anticipated synergies from integrating the respective businesses of Cenovus and Husky depends in part on, among other things, successfully consolidating functions and integrating operations, systems, procedures and personnel in a timely and efficient manner. Achieving the benefits of the Arrangement also depends on Cenovus's ability to effectively capitalize on its scale, scope and leadership position in the oil sands and wider oil and natural gas industry, to realize the anticipated capital and operating synergies and to maximize the potential of its improved growth and capital funding opportunities.

The integration of the Cenovus and Husky assets to realize the benefits of the Arrangement will require the dedication of substantial management effort, time and resources which may divert Cenovus's Management's focus and resources from other strategic opportunities and operational matters. The integration process may result in the loss of key employees and the disruption of ongoing business and employee relationships that may adversely affect Cenovus's ability to achieve the anticipated benefits of the Arrangement. Cenovus may also incur additional expenses related to the Arrangement and the integration of Cenovus and Husky, which may limit Cenovus's ability to realize some or all of the anticipated benefits of the Arrangement.

If Cenovus is not able to successfully achieve the synergies associated with the Arrangement, or the cost to achieve these synergies is greater than expected, the anticipated benefits of the Arrangement may not be realized fully, or at all, may take longer to realize than expected, or may result in unforeseeable adverse effects. There can be no assurance that Cenovus will be able to achieve the synergies or realize the anticipated benefits of the Arrangement in a timely manner or at all. Failing to realize the anticipated benefits of the Arrangement may adversely affect Cenovus's financial condition, results of operations, reputation and share price.

Cenovus's Ability to Integrate Husky's Business with its Own

Given the increased scope and complexity of our operations, Cenovus may not be able to integrate Husky's operations or restructure Cenovus's previously existing business operations without encountering difficulties and delays. The integration process could result in disruption of existing relationships with suppliers, employees, customers and other constituencies of each company. Further, Cenovus will be required to maintain its financial and strategic focus while integrating Husky's business and avoid inconsistencies in implementing uniform standards, controls, procedures and policies, as appropriate. Our ability to integrate the businesses will depend in part on our ability to access or implement some or all of the personnel and technology necessary to efficiently and effectively operate Husky's assets. There can be no assurance that management will be able to successfully integrate the businesses to achieve any of the synergies or other benefits that are expected to result from the Arrangement.

The ongoing integration process involves numerous operational, strategic, financial, accounting, legal, tax and other risks and uncertainties associated with Cenovus's and Husky's business and operations. Difficulties in integrating our businesses may result in variations in expected performance, operational challenges or the failure to realize anticipated efficiencies on the expected timelines or at all. Cenovus's and Husky's existing businesses may also be negatively impacted by the combination.

Potential difficulties that may be encountered in the integration process include, among others: (i) the inability to successfully integrate the businesses in a manner that permits Cenovus to achieve the anticipated revenue and cost savings on the expected timelines or at all; (ii) complexities associated with managing a larger, more complex, multinational integrated business; (iii) achieving the anticipated operating synergies on the expected timelines or at all; (iv) integrating personnel at all levels of the company over multiple jurisdictions, effectively and efficiently; (v) difficulties integrating and maintaining relationships with Husky's industry contacts and existing business partners; and (vi) the disruption of, or the loss of momentum in, each of Cenovus's and Husky's ongoing businesses. Such challenges may prohibit Cenovus from successfully integrating Husky's business with its own or may materially delay the integration process. A failure to integrate the business on the expected timeline, or at all, may have an adverse effect on Cenovus's financial condition, results of operations, and ability to realize the anticipated benefits of the Arrangement.

It is possible that the integration process could result in the loss of key employees to assist in the integration and operation of Husky and Cenovus, which may exacerbate integration challenges. Difficulties or delays in the integration process or the inability to partially or fully integrate Husky's business with our own could have a material adverse effect on our business, cash flow, operating results, financial condition, reputation and share price.

Costs Associated with the Integration of Cenovus's and Husky's Businesses

Cenovus may incur significant costs related to formulating and implementing ongoing integration plans, including facilities and systems consolidation costs and other employment-related costs. Cenovus will continue to assess the magnitude of these costs and additional unanticipated costs may be incurred in connection with the integration of the two companies. While Cenovus has accounted for a certain level of expenses, many factors beyond our control may affect the total amount or the timing of expenses associated with the integration process. The elimination of duplicative costs, as well as the realization of other efficiencies related to the integration of the businesses, may not offset integration-related costs and achieve a net benefit in the near term, or at all. The costs described above and any unanticipated costs and expenses related to the integration may have an adverse effect on Cenovus's financial condition and results of operations.

Increased Indebtedness

Cenovus's increased indebtedness could have adverse consequences for Cenovus, including: reducing funds available for other business purposes; limiting Cenovus's ability to obtain additional financing for working capital, capital expenditures, product development, debt service requirements, acquisitions and general corporate or other purposes; restricting Cenovus's flexibility and discretion to operate its business; limiting Cenovus's ability to declare dividends; having to dedicate a portion of Cenovus's cash flows from operations to the payment of interest on its existing indebtedness and not having such cash flows available for other purposes; exposing Cenovus to increased interest expense on borrowings at variable rates; limiting Cenovus's ability to adjust to changing market conditions; placing Cenovus at a competitive disadvantage compared with its competitors with less debt; making Cenovus more vulnerable to a downturn in general economic conditions; and reducing funds available for capital expenditures that are important to Cenovus's business.

Dilutive Effect

The issuance of Cenovus common shares pursuant to the Arrangement had an immediate dilutive effect on the ownership interest of existing shareholders of Cenovus. The issuance of additional Cenovus common shares upon exercise, from time to time, of Cenovus Warrants or Cenovus Replacement Options issued to holders of Husky common shares and Husky options prior to the Arrangement will have a further dilutive effect on the ownership interest of shareholders of Cenovus. Such issuances will have a dilutive effect on Cenovus's earnings per share, which could adversely affect the market price of Cenovus common shares and may adversely impact the value of Cenovus shareholders' investments.

It is also expected that, from time to time, Cenovus will grant additional equity awards to our employees and directors under the combined Company's compensation plans. These additional equity awards will have a further dilutive effect on Cenovus's earnings per share, which could also negatively affect the market price of the Cenovus common shares.

Potential Undisclosed and Unforeseen Liabilities Associated with the Arrangement

In connection with the Arrangement, there may be liabilities that we failed to discover, underestimated or were unable to quantify in our due diligence conducted prior to the execution of the Arrangement Agreement and completion of the Arrangement. In addition, the Arrangement may subject Cenovus to unforeseen liabilities, including environmental and regulatory liabilities in Canada and other foreign jurisdictions. Cenovus may now be subject to claims related to Husky's operations and previous actions, including those of its current and former directors and employees. We may also be subject to adverse publicity associated with such matters, regardless of whether we are ultimately found responsible and may be required to incur significant expenses or devote significant resources in defense against any litigation of such claims. The outcome of any such litigation is uncertain and may negatively impact our financial condition, results of operations and reputation.

Pro Forma Financial Information may not be Indicative of Cenovus's Financial Condition or Results following the Arrangement

The *pro forma* financial information contained in Cenovus's public disclosure record is presented for illustrative purposes only as of its respective dates and may not be indicative of the current financial condition or results of operations of Cenovus. The unaudited *pro forma* financial information was derived from the respective historical financial statements of Cenovus and Husky, and certain adjustments and assumptions were made as of such dates to give effect to the Arrangement. The information upon which these adjustments and assumptions were made was preliminary and these kinds of adjustments and assumptions are difficult to make with complete accuracy. Accordingly, the combined business, assets, results of operations and financial condition may differ significantly from those indicated in the unaudited *pro forma* financial information, and such variations may negatively impact our financial condition, results of operations and share price.

Pro Forma Reserves Information may not be Indicative of Cenovus's Reserves following the Arrangement

The *pro forma* reserves information included in the AIF is based on the reserves reports prepared by McDaniel and GLJ for Cenovus (the "2020 Cenovus Reserves Report"), and Husky's reserves estimates have been prepared by internal qualified reserves evaluators in accordance with the COGE Handbook, and have been audited and reviewed by Sproule, an independent qualified reserves auditor (the "2020 Husky Reserves Report"), each effective December 31, 2020 (collectively, the "2020 Reserves Reports"). The reserves information presented in each of the 2020 Reserve Reports has been aggregated by Cenovus for illustrative purposes. The 2020 Reserves Reports were prepared using different assumptions and an independent reserves report effective December 31, 2020 was not prepared for the combined company. Therefore, the actual reserves of the combined company, if evaluated as of December 31, 2020 may differ from the *pro forma* reserves presented in the AIF. Cenovus and Husky, as stand-alone entities, have different operational and financial capabilities, which impacts their ability to develop reserves. And finally, there are systemic differences in the future development costs for each of Cenovus and Husky.

Further, were an independent reserves evaluation to be completed on our collective reserves as a result of the Arrangement, the assumptions underlying the 2020 Husky Reserves Report may be materially different from those assumptions used to evaluate the combined company's collective reserves. Our actual reserves could vary materially from these *pro forma* estimates and the Husky reserves acquired in connection with the Arrangement may be less than expected, which could adversely affect Cenovus's business, operations, financial results and share price.

Engineering, Reserves, Economic and Environmental Assessments in connection with the Arrangement may be Inaccurate

Acquisitions of oil and natural gas properties or companies are based in large part on engineering, environmental and economic assessments made by the acquirer, independent engineers and consultants. The assessments include a series of assumptions regarding such factors as recoverability and marketability of crude oil, natural gas and refined products, environmental restrictions and prohibitions regarding releases and emissions of various substances, future commodity prices and operating costs, future capital expenditures and royalties and other government levies that may be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geologic, engineering, economic, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

Specifically, the 2020 Husky Reserves Report was prepared in respect of periods prior to completion of the Arrangement during which the crude oil and natural gas properties of Husky were operated on a stand-alone basis. Although Cenovus's Management believes the information contained in the 2020 Husky Reserves Report is reliable, Cenovus has not independently verified the historical information contained in such report and is unable to fully assess Husky's procedures for providing, assembling and reporting information to Sproule associated with Husky and its assets. In particular, the reserve and recovery information contained in the 2020 Husky Reserves Report is only an estimate and the actual production from, and ultimate reserves of, those properties may be greater or less than the estimates contained in such report.

Inclusion of Historical Information relating to Husky

The Arrangement was effected on January 1, 2021, and the integration of Cenovus's and Husky's business is ongoing. Cenovus has not yet completed independently evaluating and updating certain information relating to the assets, reserves and businesses acquired in the Arrangement and certain information contained in this MD&A and Cenovus's public disclosure record is based on historical information relating to Husky. Such historical information relating to Husky is derived from, among other things, previous Husky public disclosure and from information provided by current and former Husky directors, officers and employees. Much of the disclosure relating to Husky relates to periods prior to Cenovus's ownership of Husky, and therefore was generated by disclosure controls and procedures that may differ from those in place at Cenovus. Thus, information from the two companies may not have been generated and reported using equivalent standards. Further, Cenovus's Management's expectations about the combined entity's future performance reflect the current state of its information about Husky and its operations and there can be no assurance that such information is accurate in all material respects. Inaccuracies in historical information relating to Husky may cause Cenovus's financial and operational results to vary from our expectations, which may in turn adversely affect our financial condition, results of operations and share price.

Uncertainty related to Customers, Suppliers or Other Third Parties

As a result of the Arrangement, Cenovus may experience impacts on relationships with customers, suppliers or other third parties that may harm Cenovus's business and results of operations. Certain customers, suppliers or other third parties may seek to terminate or modify contractual obligations whether or not such contractual rights are triggered as a result of the Arrangement. There can be no guarantee that customers, suppliers or other third parties will remain with or continue to have a relationship with Cenovus or Husky or do so on the same or similar contractual terms. If any customers, suppliers or other third parties seek to terminate or modify contractual obligations or discontinue their relationships with Cenovus or Husky, then Cenovus's business and results of operations may be adversely affected.

Any disruptions with third parties could limit our ability to achieve the anticipated benefits of the Arrangement or may be detrimental to Cenovus's and Husky's existing businesses, operations and financial conditions.

Risks Associated with the Cenovus Warrants

There can be no assurance that an active public market for the Cenovus Warrants will be sustained. If such a market is sustained, the market price of the Cenovus Warrants may be adversely affected by a variety of factors relating to Cenovus's business, including, without limitation, fluctuations in Cenovus's operating and financial results, the results of any public announcements made by Cenovus and Cenovus's failure to meet analysts' expectations. In addition, the market price of the Cenovus common shares will significantly affect the market price of the Cenovus Warrants. This may result in significant volatility in the market price of the Cenovus Warrants and may negatively impact the value of the Cenovus Warrants.

Holders of Cenovus Warrants will experience dilution if the combined company issues additional Cenovus common shares in future offerings or under outstanding Cenovus Replacement Options and Cenovus Warrants. Such dilution may adversely affect the market price of the Cenovus common shares and may negatively impact the value of Cenovus shareholders' investments.

Risks Related to Significant Shareholders of Cenovus

As of January 1, 2021, Hutchison Whampoa Europe Investments S.à r.l. ("Hutchison"), L.F. Investments S.à r.l ("L.F. Investments"), and ConocoPhillips own 15.7 percent, 11.5 percent and 10.3 percent of the common shares of Cenovus, respectively. Although each of Hutchison and L.F. Investments are subject to restrictions from selling or transferring Cenovus common shares through July 1, 2022 pursuant to the terms of their respective standstill agreement with Cenovus, the sale of Cenovus common shares held by any of Hutchison, L.F. Investments or ConocoPhillips into the market, either through open market trades on the Toronto and New York stock exchanges, through privately arranged block trades, or pursuant to prospectus offerings made in accordance with the respective registration rights agreement that each of Hutchison, L.F. Investments and ConocoPhillips have entered into with Cenovus, or market perception regarding ConocoPhillips' intention to sell Cenovus common shares, could adversely affect market prices for Cenovus common shares.

While Hutchison and L.F. Investments are each subject to certain voting covenants pursuant to the terms of a standstill agreement they each entered into with Cenovus in connection with the Arrangement, each of Hutchison and L.F. Investments may be able to impact certain matters requiring shareholder approval.

Amount of Contingent Payments Payable to ConocoPhillips

In connection with the Conoco Acquisition, we agreed to make contingent payments under certain circumstances. The amount of contingent payments vary depending on the Canadian dollar WCS price from time to time during the five year period following the closing of the Conoco Acquisition (May 17, 2017), and such payments may be significant. In addition, in the event that such further payments are made, this could have an adverse impact on our reported results and other metrics.

Tax Laws

Income tax laws, other laws or government incentive programs may in the future be changed or interpreted in a manner that adversely affects Cenovus, its financial results and its shareholders. Tax authorities having jurisdiction over Cenovus may disagree with the manner in which we calculate our tax liabilities such that its provision for income taxes may not be sufficient, or such authorities could change their administrative practices to Cenovus's detriment or the detriment of its shareholders. In addition, all of our tax filings are subject to audit by tax authorities who may disagree with such filings in a manner that adversely affects Cenovus and its shareholders.

U.S. Tax Risk

In January 2021, a new U.S. presidential administration took office. The new administration campaigned on a platform that included several tax provisions that could potentially be detrimental to Cenovus. Those provisions included an increase in the U.S. federal corporate tax rate and a new corporate minimum tax. While the ability of the new administration to enact tax laws is uncertain, it is possible that Cenovus's U.S. operations will be subject to increased levels of U.S. federal taxation in the future.

A discussion of additional risks, should they arise after the date of this MD&A, which may impact our business, prospects, financial condition, results of operation and cash flows, and in some cases our reputation, can be found in our subsequently filed MD&A, available on SEDAR at sedar.com, on EDGAR at sec.gov and cenovus.com.

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.

Joint Arrangements

The classification of a joint arrangement as either a joint operation or a joint venture requires judgment. Cenovus holds a 50 percent interest in WRB, a jointly controlled entity. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of WRB. As a result, the joint arrangement is classified as a joint operation and the Company's share of the assets, liabilities, revenues and expenses are recorded in the Consolidated Financial Statements.

In determining the classification of its joint arrangements under IFRS 11, "*Joint Arrangements*", the Company considered the following:

- The intention of the joint arrangement was to form an integrated North American heavy oil business. The integrated business was structured, initially on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.
- The partnership agreements require the partners (Cenovus and Phillips 66 or respective subsidiaries) to make contributions if funds are insufficient to meet the obligations or liabilities of the partnerships. The past and future development of WRB is dependent on funding from the partners by way of partnership notes payable and loans.
- The WRB working interest relationship is operated whereby the operating partner takes product on behalf of the participants and is modified to account for the operating environment of the refining business.
- Phillips 66, as the operator, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnership from undertaking these roles themselves. In addition, the partnership does not have employees and, as such, are not capable of performing these roles.
- In the arrangement, output is taken by the partners, indicating that the partners have the rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangement.

Exploration and Evaluation Assets

The application of the Company's accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have reached a stage where technical feasibility and commercial viability cannot be reasonably determined. Factors such as drilling results, future capital programs, future operating expenses, as well as estimated reserves and resources are considered. In addition, Management uses judgment to determine when E&E assets are reclassified to PP&E. In making this determination, various factors are considered, including the existence of reserves, and whether the appropriate approvals have been received from regulatory bodies and the Company's internal approval process.

Identification of CGUs

CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretation. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure, and the manner in which Management monitors and makes decisions about its operations. The recoverability of the Company's upstream, refining, crude-by-rail terminal, railcars, storage tanks, and corporate assets are assessed at the CGU level. As such, the determination of a CGU could have a significant impact on impairment losses and reversals.

Determining the Lease Term

In determining the lease term, Management considers all facts and circumstances that create an economic incentive to exercise an extension option, or not exercise a termination option. The assessment is reviewed if a significant event or a significant change in circumstances occurs which affects this assessment.

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 following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that, if changed, could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

In March 2020, the World Health Organization declared a global pandemic following the emergence and rapid spread of COVID-19. The outbreak and subsequent measures intended to limit the pandemic contributed to significant declines and volatility in financial markets. The pandemic has adversely impacted global commercial activity, including significantly reducing worldwide demand for crude oil.

The full extent of the impact of COVID-19 on the Company's 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.

The outbreak and current market conditions have increased the complexity of estimates and assumptions used to prepare the annual Consolidated Financial Statements, particularly related to recoverable amounts.

In addition, the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels could result in a change in assumptions used in determining the recoverable amount and could affect the carrying value of the related assets. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain.

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

Crude Oil and Natural Gas Reserves

There are a number of inherent uncertainties associated with estimating crude oil and natural gas reserves. Reserves estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test fair value less costs to sell and DD&A expense of the Company's crude oil and natural gas assets in the Oil Sands and Conventional segments. The Company's reserves are evaluated annually and reported to the Company by its IQREs.

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. For the Company's upstream assets, these estimates include forward commodity prices, expected production volumes, quantity of reserves and resources, discount rates, future development and operating expenses. Recoverable amounts for the Company's refining assets, crude-by-rail terminal and related ROU assets use assumptions such as throughput, forward commodity prices, market crack spreads, operating expenses, transportation capacity, future capital expenditures, supply and demand conditions and the terminal values used. Recoverable amounts for the Company's real estate ROU assets use assumptions such as real estate market conditions which includes market vacancy rates and sublease market conditions, price per square footage, real estate space availability and borrowing costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

2020 Upstream Impairments

The recoverable amounts of Cenovus's upstream CGUs were determined based on FVLCOD. Key assumptions in the determination of future cash flows from reserves include crude oil, NGLs and natural gas prices, costs to develop and the discount rate. The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates at December 31, 2020. All reserves have been evaluated as at December 31, 2020 by the IQREs.

Crude Oil, NGLs and Natural Gas Prices

The forward prices as at December 31, 2020, used to determine future cash flows from crude oil, NGLs and natural gas reserves were:

	2021	2022	2023	2024	2025	Average Annual Increase Thereafter (percent)
WTI (US$/barrel)	47.17	50.17	53.17	54.97	56.07	2.0%
WCS (C$/barrel)	44.63	48.18	52.10	54.10	55.19	2.0%
Edmonton C5+ (C$/barrel)	59.24	63.19	67.34	69.77	71.18	2.0%
AECO (1) (C$/Mcf)	2.88	2.80	2.71	2.75	2.80	2.0%

(1) Assumes gas heating value of one million British thermal units per thousand cubic feet.

Discount and Inflation Rates

Discounted future cash flows are determined by applying a discount rate between 10 percent and 15 percent based on the individual characteristics of the CGU, and other economic and operating factors. Inflation is estimated at approximately two percent.

2020 Refining Impairments

The recoverable amount (Level 3) of the Borger CGU was determined using FVLCOD. The FVLCOD was calculated based on discounted after-tax cash flows using forward prices and cost estimates. Key assumptions in the determination of future cash flows included forward crude oil prices, forward crack spreads, future capital expenditures, operating costs, the terminal values and the discount rate. Forward crack spreads were based on quoted near-month contracts for WTI and spot prices for gasoline and diesel.

Crude Oil and Forward Crack Spreads

Forward prices are based on Management's best estimate and corroborated with third-party data. As at September 30, 2020, the forward prices used to determine future cash flows were:

- WTI forward prices used for 2021 to 2022 ranged from US$36.36 per barrel to US$50.84 per barrel and 2023 to 2025 ranged from US$49.66 per barrel to US$58.74 per barrel.
- WTI to West Texas Sour differential used for 2021 to 2022 ranged from US$0.37 per barrel to US$1.73 per barrel and 2023 to 2025 ranged from US$1.21 per barrel to US$1.81 per barrel.
- Group 3 forward market crack spread used for 2021 to 2022 ranged from US$11.56 per barrel to US$13.23 per barrel and 2023 to 2025 ranged from US$11.79 per barrel to US$16.58 per barrel.
- Subsequent prices were extrapolated using a two percent growth rate to determine future cash flows up to year 2035.

Discount and Inflation Rates

Discounted future cash flows are determined by applying a discount rate of 10 percent based on the individual characteristics of the CGU, and other economic and operating factors.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of the Company's upstream assets, refining assets and crude-by-rail terminal at the end of their economic lives. Management uses judgment to assess the existence and to estimate the future liability. The actual cost of decommissioning and restoration is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit-adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

Fair Value of Assets Acquired and Liabilities Assumed in a Business Combination

The fair value of assets acquired and liabilities assumed in a business combination, including contingent consideration and goodwill, is estimated based on information available at the date of acquisition. Various valuation techniques are applied for measuring fair value including market comparables and discounted cash flows which rely on assumptions such as forward commodity prices, reserves and resources estimates, production costs, volatility, Canadian-U.S. foreign exchange rates and discount rates. Changes in these variables could significantly impact the carrying value of the net assets.

Income Tax Provisions

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. There are usually a number of tax matters under review; therefore, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recorded to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. There are some transactions for which the ultimate tax determination is uncertain. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods.

Changes in Accounting Policies

There were no new or amended accounting standards or interpretations adopted during the year ended December 31, 2020.

New Accounting Standards and Interpretations not yet Adopted

There are new standards, amendments to accounting standards and interpretations that are effective for annual periods beginning or after January 1, 2021 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2020. These standards and interpretations are not expected to have a material impact on our Consolidated Financial Statements. The standard applicable to us is as follows and will be adopted on its respective effective date:

Interest Rate Benchmark Reform

On August 27, 2020, the IASB published Interest Rate Benchmark Reform – Phase 2 (Amendments to IFRS 9, "*Financial Instruments*", IAS 39, "*Financial Instruments: Recognition and Measurement*", IFRS 7, "*Financial Instruments: Disclosure*s", IFRS 4, "*Insurance Contracts*" and IFRS 16) ("IBOR Phase 2 Amendments"), which provides clarity on the changes after the reform of an interest rate benchmark. The amendments are effective for annual periods beginning on or after January 1, 2021, with early application permitted. The IBOR Phase 2 Amendments primarily relate to the modification of financial instruments, allowing for a practical expedient for modifications required by the reform. The practical expedient for modifications is accounted for by updating the effective interest rate without modification of the financial instrument and is subject to satisfying all qualifying criteria. We expect the IBOR Phase 2 Amendments will not have a significant impact on our Consolidated Financial Statements.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, assessed the design and effectiveness of ICFR and disclosure controls and procedures ("DC&P") as at December 31, 2020. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of ICFR. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2020.

The effectiveness of our ICFR was audited as at December 31, 2020 by PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, as stated in their Report of Independent Registered Public Accounting Firm, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2020.

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.

SUSTAINABILITY

At Cenovus, sustainability is essential to the way we do business. It means creating a safe and inclusive workplace, partnering with local and Indigenous communities, and innovating to minimize our impact on the environment. We believe striking the right balance among environmental, economic and social considerations creates long-term value.

To support our sustainability performance, our *Sustainability Policy* guides our activities in the areas of: Leadership and Governance, People, Environment, Stakeholder Engagement, Indigenous Engagement, and Community Involvement and Investment.

Cenovus is committed to world-class safety performance and ESG leadership. This includes ambitious ESG targets, robust management systems and transparent performance reporting. The Company will continue working to earn its position as a global energy supplier of choice by advancing clean technology and reducing emissions intensity. This includes the ambition of achieving net zero emissions by 2050. Cenovus will also continue building upon its strong local community relationships, with a focus on Indigenous economic reconciliation.

The targets Cenovus released in 2020 for its key ESG focus areas are the product of robust processes to ensure alignment with the Company's business plan and strategy. Cenovus remains committed to pursuing ESG targets now that it has completed the Arrangement with Husky and will undertake a similarly thorough analysis before setting meaningful targets for the new portfolio. Once that work is complete in 2021 and approved by the Board, the new targets and plans to achieve them will be disclosed.

We published our 2019 ESG report in July 2020 to report on our management efforts and performance across the areas within our *Sustainability Policy* that are important to our stakeholders. Our ESG report is available on our website at cenovus.com.

OUTLOOK

We expect 2021 to be a challenging time for our industry and the global economy in general due to the impacts of COVID-19. 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 in 2021 with recovery dependent on the success of economic relaunches. We anticipate that an increase in demand for refined products will be an early indicator of recovery. 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 to assess how we manage our Upstream production levels. Our assets can respond to market signals and ramp up production accordingly. Our decisions around production levels and refinery crude run rates will be focused on maximizing the value we receive for our products. We expect our 2021 annual Upstream production to average between 730,000 BOE per day and 780,000 BOE per day and total Downstream throughput of 500,000 barrels per day to 550,000 barrels per day.

With the close of the Arrangement, we estimated approximately $600 million in annual corporate and operating synergies and approximately $600 million in capital allocation synergies to be achievable. The 2021 budget positions us to achieve about $400 million of the estimated annual corporate and operating synergies and all of the estimated capital allocation synergies this year. Over the longer-term, we anticipate additional cost savings and margin enhancements based on further physical integration of upstream assets with downstream assets, which is expected to shorten the value chain and reduce condensate costs associated with heavy oil transportation. 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.

Given the challenges faced by our industry and the global economy and the closing of the Arrangement with Husky, achieving cumulative free funds flow of approximately $11 billion through 2024, as disclosed in our news release dated October 2, 2019, is under evaluation. We expect to develop a new five-year business plan for the Company later this year.

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

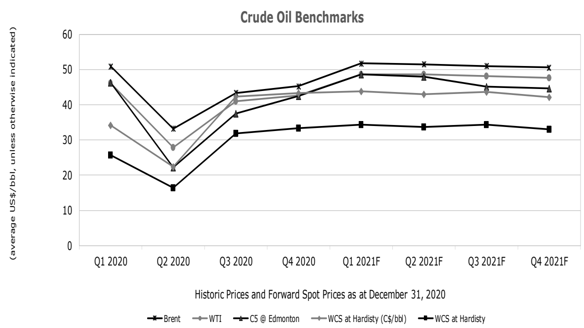
Commodity Prices Underlying our Financial Results

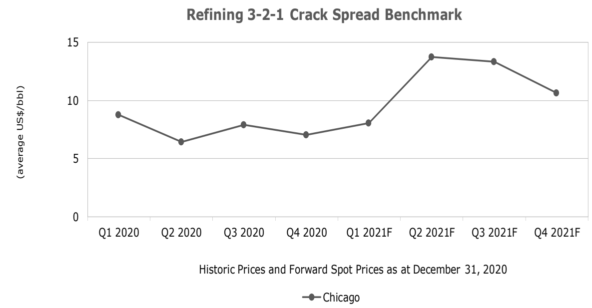
Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for light crude oil prices will be tied primarily to the supply and demand response to the current uncertain price environment, the impact of oversupply, and global demand impacts amid COVID-19 concerns;
- Crude oil and refined product price volatility is expected to continue due to crude demand destruction as a result of COVID-19;
- The effectiveness and successful distribution of vaccines will be key to the pace of oil demand 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 project, and the level of crude-by-rail activity; and
- We expect refining market crack spreads in 2021 to remain weak relative to normal as a result of significantly reduced refined products demand due to COVID-19, particularly in the first half of the year. Refining market

crack spreads are expected to continue to fluctuate, adjusting for seasonal trends and refining run cuts in North America.

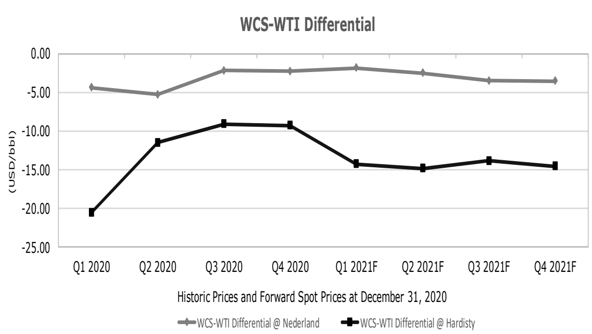
Natural gas and NGLs production associated with our Conventional assets provide improved upstream integration for the fuel, solvent and blending requirements at our Oil Sands operations.

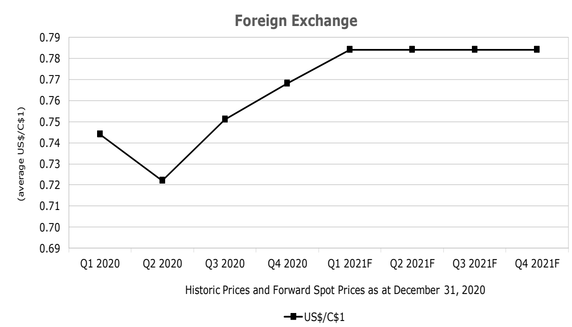




Natural gas prices have been challenged due to weaker demand as a result of COVID-19, but the forward curve is showing that the market expects AECO prices to rebound into 2021. Production declines from both associated gas and dry gas, along with rebounding U.S. demand and liquified natural gas exports, should tighten North American gas fundamentals 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 and is expected to continue to hold the interest rate until 2023.





Our upstream crude oil production and most of our downstream refined products are exposed to movements in the WTI crude oil price. With the closing of the Arrangement, our exposure has grown on both the upstream and downstream sides of our business.

Our refining capacity is now focused in the U.S. Midwest along with smaller exposures to the USGC and Alberta. Cenovus is exposed to the crack spread in all of these markets.

Our exposure to crude differentials includes light-heavy and light-medium price differentials. Light-medium price differential exposure is focused on light-medium crudes in the U.S. Midwest market region where we have refining capacity, and to a lesser degree in the USGC and Alberta. Our exposure to light-heavy crude oil price differentials is composed of a global light-heavy component, a regional component in markets we transport barrels to, as well as the Alberta differential, which is subject to transportation constraints. While we expect to see volatility in crude oil prices, we have the ability to partially mitigate the impact of crude oil and refined product prices and 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 as well as from spreads on 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;
- Traditional crude oil storage tanks in various geographic locations; and
- Financial hedge transactions – limiting the impact of fluctuations in crude oil and refined product prices by entering into financial transactions related to our exposures.

Key Priorities For 2021

We recently developed and shared updated guidance on January 28, 2021. In the current commodity price environment, we continue to focus on maintaining balance sheet strength and liquidity. Enhancing our financial resilience and flexibility while continuing to deliver safe and reliable operations will continue to be a top priority during these uncertain times.

Our corporate strategy focuses on maximizing shareholder value through cost leadership and realizing the best margins for our products. We expect to remain focused on disciplined capital investment allocation among the full suite of assets for the Company, and continued cost leadership to achieve margin improvement and environmental benefits.

Safe and Reliable Operations

Safe and reliable operations are our number one priority. Safety continues to be a core value that informs all of the decisions we make. We will continue to promote a safety culture in all aspects of our work and use a variety of programs to keep safety top of mind at all times.

Capture Synergies and Maintain Cost Leadership

The combination with Husky will further improve cost structure. The 2021 budget positions us to achieve about $400 million of annual corporate and operating synergies and an estimated $600 million in capital allocation synergies in 2021.

The annual corporate and operating cost synergies is well underway and is expected through the consolidation of information technology systems, eliminating other service overlaps, and through reductions to combined workforce and corporate overhead costs. Immediate efficiencies are also expected by implementing best practices from each company, including applying Cenovus's operating expertise to Husky's oil sands assets, leveraging the increased portfolio's scale, and pursuing commercial and contract-related efficiencies on transportation, storage, and logistics marketing and blending opportunities.

Over the longer term, we anticipate additional cost savings and margin enhancements based on further physical integration. The integration of Cenovus's upstream assets with Husky's downstream and transportation, storage, and logistics portfolio is expected to shorten the value chain and reduce condensate costs associated with heavy oil transportation over the longer term.

We continue to achieve improvements in our operating and G&A costs. In 2021, we will continue to look for ways to improve efficiencies across Cenovus to drive incremental capital, operating and G&A cost reductions.

Disciplined Capital Investment

We released our 2021 guidance on January 28, 2021 for the Company and anticipate our total capital expenditures to be between $2.3 billion and $2.7 billion, including sustaining capital of approximately $2.1 billion and costs of $520 million to $570 million (excluding insurance proceeds) for the Superior Refinery rebuild. We will continue to be disciplined with our capital. The 2021 guidance is available on our website at cenovus.com.

Oil Sands capital investment for 2021, including Christina Lake, Foster Creek, Sunrise and Tucker oil sands projects, as well as the Lloydminster thermal projects and Cold and Enhanced Oil Recovery, is forecast to be between $850 million and $950 million. Oil Sands capital is primarily for sustaining production focused at Christina Lake, Foster Creek and the Lloydminster thermal assets. Our Oil Sands production is expected to range between 524,000 and 586,000 barrels per day for 2021.

Our Conventional segment capital investment is forecasted to be between $170 million and $210 million. This includes economic development in various plays to generate strong returns, improve underlying cost structures through volume enhancement and offset declines. Production is expected to range between 132,000 and 151,000 BOE per day for 2021.

Our Offshore segment, including operations and exploration prospects in the Asia Pacific region and Atlantic Canada region, capital investment is expected to be between $200 million and $250 million. This capital spend includes planned wells in China and continued development of the fields in the MDA-MBH and MDK fields in the Madura Strait, as well as baseline preservation capital for the West White Rose Project, which has been deferred for 2021 while we continue to evaluate options. Working Interest production from our Offshore segment is expected to range between 61,000 and 72,000 barrels per day.

In 2021, the Downstream segment, composed of Canadian and U.S. Manufacturing and Retail, we expect to invest between $1.0 billion and $1.2 billion and will continue to focus on refining reliability and maintenance, safety projects and high-return optimization opportunities as well as between $520 million and $570 million for the Superior rebuild project. The rebuild project will further improve our integration while reducing the Company's exposure to WTI-WCS location differentials. Downstream throughput is expected to be in the range of 500,000 barrels per day to 550,000 barrels per day.

We expect to invest between $75 million and $100 million of corporate capital in 2021 across the Company.

In 2021, we plan to achieve capital allocation synergies across the Company by optimizing sustaining capital to the highest quality assets while maintaining safe and reliable operations across our portfolio.

As at December 31, 2020, our Net Debt position was $7.2 billion. The estimated incremental annual free funds flow from identified near-term synergies with the closing of the Arrangement is expected to accelerate balance sheet deleveraging. Through a combination of cash on hand and available capacity on our committed credit facilities and demand facilities, we have approximately $10.4 billion of liquidity under the combined company. In addition, WRB has available capacity of approximately $70 million, for Cenovus's proportionate share, on its demand facilities. We will continue to focus on allocating free funds flow to reduce Net Debt to less than $10 billion and target a longer-term Net Debt level at or below $8 billion.

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. The Arrangement removes a significant amount of exposure to WTI-WCS location differentials and reduces commodity price volatility. Our financial framework and flexible business plan allow multiple options to manage our balance sheet. We will continue to assess our spending plans on a regular basis while closely monitoring crude oil prices in 2021.

The Company's priority will be to maximize free funds flow by focusing investments on sustaining capital expenditures which will position us to direct available free funds flow to the balance sheet and allow us to achieve a Net Debt target of $10 billion which approximates a Net Debt to Adjusted EBITDA target of less than 2.0 times, without the need for asset dispositions.

The low funds flow volatility, breakeven prices and corporate sustaining costs supports an investment grade profile and lower cost of capital through the commodity price cycle. We remain committed to maintaining our investment grade credit ratings.

Shareholder Returns

After achieving our balance sheet objectives, the Company's free funds profile is expected to enable sustainable growth in shareholder distributions. The Board declared a first quarter dividend of $0.0175 per common share, payable on March 31, 2021, to common shareholder of record as of March 15, 2021. The Board declared a first quarter dividend on the Series 1, 2, 3, 5, and 7 preferred shares, payable on March 31, 2021, in the amount of $8 million.

ESG

We are committed to ESG leadership. This includes ambitious ESG targets, robust management systems and transparent performance reporting. The Company will continue working to earn its position as a global energy supplier of choice by advancing clean technology and reducing emissions intensity. This includes the ambition of achieving net zero emissions by 2050. We will also continue building upon our strong local community relationships, with a focus on Indigenous economic reconciliation.

The targets Cenovus released in 2020 for its key ESG focus areas are the product of robust processes to ensure alignment with the company's business plan and strategy. We remain committed to pursuing ESG targets now that we have completed the Arrangement with Husky and will undertake a similarly thorough analysis before setting meaningful targets for the new portfolio. Once that work is complete in 2021 and approved by the Board, the new targets and plans to achieve them will be disclosed.

ADVISORY

Oil and Gas Information

The estimates of Cenovus's reserves were prepared effective December 31, 2020 by IQREs, based on the COGE Handbook and in compliance with the requirements of NI 51-101. Estimates are presented using the IQRE Average forecast prices and costs dated January 1, 2021 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, 2020.

Total proved reserves and total proved plus probable reserves for Cenovus and Husky are based on a simple summation of reserves prepared independently for each company. Cenovus has not constructed a consolidated reserves report of the combined assets of Cenovus and Husky, and has not engaged an independent reserves evaluator to produce such a report in accordance with NI 51-101. Reserves calculated for the combined company could be materially different than reserves calculated by adding the reserves of the two companies. The anticipated increase in reserves for the combined company may be more or less than anticipated, and the difference could be material.

Cenovus and Husky employed different methodologies to estimate their reserves information for the year ended December 31, 2020. All of Husky's oil and gas reserves estimates were prepared by internal qualified reserves evaluators using a formalized process for determining, approving and booking reserves. As a result, the actual reserves of Cenovus (after giving effect to the Arrangement), if calculated as of December 31, 2020 by an independent reserves evaluator in accordance with NI 51-101, may differ from the anticipated total proved reserves and total proved plus probable reserves of the combined company for a number of reasons, and such differences may be material. 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 "achieve", "aim", "anticipate", "believe", "can be", "capacity", "committed", "commitment", "continue", "could", "deliver", "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, but not limited to, statements about: strategy and related milestones; schedules and plans; anticipated benefits of the Arrangement, including: achieving $1.2 billion of incremental annual free funds flow comprised of approximately $600 million in annual corporate and operating synergies and approximately $600 million in annual sustaining capital allocation synergies independent of commodity prices with the majority of annual savings achieved within the first year of combined operations and the full amount achieved within year two, the impact of the Arrangement on certain reserves data and other oil and gas information, including any *pro forma* information, the planned amalgamation of Cenovus and Husky, achieving longer term cost savings and margin enhancements based on further physical integration, reducing our exposure to Alberta heavy oil price differentials while maintaining exposure to global commodity prices, reducing condensate costs associated with heavy oil transportation over the longer term, accelerating balance sheet deleveraging, achieving sustainable growth in shareholder distributions; improving efficiencies to drive incremental capital, operating and G&A cost reductions; the ability of our assets to respond to market signals and ramp up production accordingly; statements and expectations relating to our 2021 budget; our ability to partially mitigate the impact of crude oil and refined product differentials through transportation commitments, integration, marketing agreements, dynamic storage, traditional storage tanks and financial hedge contracts; maintaining an investment grade credit rating; achieving Net Debt to Adjusted EBITDA target of less than 2.0 times without the need for asset dispositions; our focus on allocating free funds flow to reduce Net Debt to less than $10 billion and targeting a longer-term Net Debt level at or below $8 billion; focus on maximizing shareholder value through disciplined capital investment and cost leadership to realize the best margins for our products and environmental benefits; maintaining liquidity, delivering a stable cash flow through price cycles and preserving a resilient balance sheet by reducing spending while maintaining safe and reliable operations; the expected production levels of our business segments in 2021; 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 to 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 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; our ability to reduce spending in response to commodity prices and other economic factors in order to maintain our financial resilience; ample liquidity and runway to sustain operations through a prolonged market downturn; anticipated volatility of demand and crude oil prices through 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 applicable federal, provincial, state and local governments and public health officials; expected recovery of the price of and demand for crude oil and refined products over the longer term as COVID-19 vaccines are administered and economies re-open from the impacts of the pandemic; expected timing for oil sands expansion phases projections for 2021 and future years and our plans and strategies to realize such projections; 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 2021 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 and crude oil price differentials; 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 project, and the level of crude-by-rail activity; our expectation that in 2021 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 2021; 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; our expectation that any liabilities that may arise out of legal claims associated with the normal course of our operations are not likely to have a material effect on our Consolidated Financial Statements; the availability and repayment of our credit facilities; potential asset sales; expected impacts of the contingent payment to ConocoPhillips; development of a new five-year business plan for the combined company in 2021; statements about new ESG targets and plans to achieve them; 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.

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 predicated or estimated, and can be profitably produced in the future.

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; our ability to realize the benefits and anticipated cost synergies associated with the combination of

Cenovus and Husky; Cenovus's ability to successfully integrate the business of Husky, including new business activities, assets, operating areas, regulatory jurisdictions, personnel and business partners for Cenovus; the accuracy of any assessments undertaken in connection with the Husky Arrangement and any resulting *pro forma* information; 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; the absence of significant adverse changes to legislation and regulations, Indigenous relations, interest rates, foreign exchange rates, competitive conditions and the supply and demand for crude oil and natural gas, NGLs, condensate and refined products; the political, economic and social stability of jurisdictions in which Cenovus operates; the absence of significant disruption of operations, including as a result of harsh weather, natural disaster, accident, civil unrest or other similar events; the prevailing climatic conditions in Cenovus's operating locations; achievement of further cost reductions and sustainability thereof; applicable royalty regimes, including expected royalty rates; future improvements in availability of product transportation capacity; increase to our share price and market capitalization over the long term; opportunities to repurchase shares for cancellation at prices acceptable to us; cash flows, cash balances on hand and access to credit and demand facilities being sufficient to fund capital investments; foreign exchange rate risk, including with respect to our US$ debt and refining capital and operating expenses; our ability to reduce our 2021 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 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 project, 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; the accuracy of 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, timely and cost effective implementation of capital projects or stages thereof; our ability to generate sufficient cash flow to meet our current and future obligations; the sufficiency of existing cash balances, internally generated cash flows, existing credit facilities, management of the Corporation's asset portfolio and access to capital markets to fund future development costs and dividends, including any increase thereto; 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; the stability of general domestic and global economic, market and business conditions; forecast inflation and other assumptions inherent in Cenovus's 2021 guidance available on cenovus.com and as 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.

2021 guidance, as updated January 28, 2021 and available on cenovus.com, assumes: Brent prices of US$49.50/bbl, WTI prices of US$46.50/bbl; WCS of US$32.50/bbl; Differential WTI-WCS of US$14.00/bbl; AECO natural gas prices of $2.50/Mcf; Chicago 3-2-1 crack spread of US$11.00/bbl; and an exchange rate of $0.78 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially from the forward-looking information, include, but are not limited to: the effect of the COVID-19 pandemic on our business, including any related restrictions, containment, and treatment measures taken by varying levels of government in the jurisdictions in which we operate; the success of our new COVID-19 workplace policies and the return of our people to our workplace; our ability to achieve the benefits and anticipated cost synergies anticipated with the Arrangement in a timely manner or at all; the ability of Cenovus and Husky to amalgamate; Cenovus's ability to successfully integrate Husky's business with its own in a timely and cost effective manner or at all; the effects of entering new business activities; unforeseen or undisclosed liabilities associate with the Arrangement; the inaccuracy of any assessments undertaken in connection with the Arrangement and any resulting *pro forma* information; the inaccuracy of any information provided by Husky; 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; the effect of Cenovus's increased indebtedness; the effect of new significant shareholder; volatility of and other assumptions regarding commodity prices; the duration of the market downturn; foreign exchange risk, including related to agreements denominated in foreign currencies; 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 project, 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; 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; the 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 the 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; the accuracy of our reserves, future production and future net revenue estimates; the accuracy of our accounting estimates and judgements; our ability to replace and expand oil and gas reserves; the costs to acquire exploration rights, undertake geological studies, appraisal drilling and project developments; 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 operations and 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 resulting in operational interruptions, including blowouts, fires, explosions, railcar incidents or derailments, aviation incidents, gaseous leaks, migration of harmful substances, loss of containment, releases or spills, including releases or spills from offshore facilities and shipping vessels at terminals or hubs and as a result of pipeline or other leaks, corrosion, epidemics or pandemics, and catastrophic events, including, but not limited to, war, extreme weather events, natural disasters, iceberg incidents, acts of vandalism and terrorism, and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites and other accidents or similar events; refining and marketing margins; cost escalations, including inflationary pressures on operating costs, such as labour, materials, natural gas and other energy sources used in oil sands processes and increased insurance deductibles or premiums; the cost and availability of equipment necessary to our operations; potential failure of products to achieve or maintain acceptance in the market; risks associated with the energy industry's and Cenovus's reputation, social license to operate and litigation related thereto; unexpected cost increases or technical difficulties in operating, constructing 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; geo-political and other risks associated with our international operations; risks associated with climate change and our assumptions relating thereto; the timing and the costs of well and pipeline construction; our ability to access markets and 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 leadership and personnel, and equipment in a timely and cost efficient manner; changes in labour demographics and relationships, including with any unionized workforces; unexpected abandonment and reclamation costs; changes in the regulatory frameworks, permits and approvals in any of the locations in which we operate or to any of the infrastructure upon which we rely; government actions or regulatory initiatives to curtail energy operations or pursue broader climate change agendas; changes to regulatory approval processes 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, social and economic conditions in the jurisdictions in which we operate or supply; the status of our relationships with the communities in which we operate, including with Indigenous communicates; the occurrence of unexpected events such as protests, 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.

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, and to the risk factors described in other documents Cenovus files from time to time with securities regulatory authorities in Canada, available on SEDAR at sedar.com, and with the U.S. Securities and Exchange Commission on EDGAR at sec.gov, and on the Corporation's website at cenovus.com. Additional information concerning Husky's business and assets as of December 31, 2020 may be found in the Husky AIF and this MD&A, each of which is filed and available on SEDAR under Husky's profile at sedar.com.

Information on or connected to Cenovus's at website cenovus.com or Husky's website at huskyenergy.com does not form part of this MD&A unless expressly incorporated by reference herein.

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		

DEFINITIONS

Scope 1 emissions are direct emissions from owned or operated facilities. Cenovus accounts for emissions on a gross operatorship basis. This includes fuel combustion, venting, flaring and fugitive emissions. It does not include emissions from the 50 percent non-operated ownership in the Company's refineries or emissions from non-operated Conventional assets.

Scope 2 emissions are indirect emissions from the generation of purchased energy for the Company's operated facilities. For Cenovus, this is limited to electricity imports.

NETBACK RECONCILIATIONS

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

Total Production

Upstream Financial Results

	Per Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Year Ended December 31, 2020 ($ millions)	Oil Sands (1)	Conventional (1) (2)	Total Upstream	Condensate	Inventory	Internal Usage (3)	Other	Total Upstream
Gross Sales	7,514	635	8,149	(3,452)	-	(295)	(58)	4,344
Royalties	324	40	364	-	6	-	-	370
Transportation and Blending	4,399	81	4,480	(3,452)	285	-	-	1,313
Operating	1,094	318	1,412	-	25	(295)	(33)	1,109
Inventory Write-Down (Reversal)	316	-	316		(316)			-
Netback	1,381	196	1,577	-	-	-	(25)	1,552
(Gain) Loss on Risk Management	268	-	268	-	-	-	-	268
Operating Margin	1,113	196	1,309	-	-	-	(25)	1,284

	Per Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Year Ended December 31, 2019 ($ millions)	Oil Sands (1)	Conventional (1) (2)	Total Upstream	Condensate	Inventory	Internal Usage (3)	Other	Total Upstream
Gross Sales	10,838	691	11,529	(4,021)	-	(222)	(64)	7,222
Royalties	1,143	30	1,173	-	-	-	1	1,174
Transportation and Blending	5,152	82	5,234	(4,021)	-	-	1	1,214
Operating	1,039	337	1,376	-	-	(222)	(33)	1,121
Netback	3,504	242	3,746	-	-	-	(33)	3,713
(Gain) Loss on Risk Management	23	-	23	-	-	-	-	23
Operating Margin	3,481	242	3,723	-	-	-	(33)	3,690

	Per Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Year Ended December 31, 2018 ($ millions) (4)	Oil Sands(1)	Conventional(1) (2)	Continuing Operations	Condensate	Inventory	Internal Usage(3)	Other	Continuing Operations
Gross Sales	10,026	904	10,930	(4,993)	-	(179)	(69)	5,689
Royalties	473	73	546	-	-	-	-	546
Transportation and Blending	5,879	90	5,969	(4,993)	-	-	(4)	972
Operating	1,037	403	1,440	-	-	(179)	(37)	1,224
Netback	2,637	338	2,975	-	-	-	(28)	2,947
(Gain) Loss on Risk Management	1,551	26	1,577	-	-	-	-	1,577
Operating Margin	1,086	312	1,398	-	-	-	(28)	1,370

(1) Found in Note 1 of the 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.
(4) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Three Months Ended December 31, 2020 ($ millions)	Oil Sands (5)	Conventional (5) (6)	Total Upstream	Condensate	Inventory	Internal Usage (7)	Other	Total Upstream
Gross Sales	2,227	184	2,411	(853)	-	(92)	(17)	1,449
Royalties	131	12	143	-	-	-	-	143
Transportation and Blending	1,131	18	1,149	(853)	-	-	-	296
Operating	309	72	381	-	-	(92)	(10)	279
Inventory Write-Down (Reversal)	-	-	-	-	-	-	-	-
Netback	656	82	738	-	-	-	(7)	731
(Gain) Loss on Risk Management	40	-	40	-	-	-	-	40
Operating Margin	616	82	698	-	-	-	(7)	691

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

Three Months Ended December 31, 2019 ($ millions)	Per Interim Consolidated Financial Statements: Oil Sands [(1)]	Per Interim Consolidated Financial Statements: Conventional [(1)(2)]	Per Interim Consolidated Financial Statements: Total Upstream	Adjustments: Condensate	Adjustments: Inventory	Adjustments: Internal Usage [(3)]	Adjustments: Other	Basis of Netback Calculation: Total Upstream
Gross Sales	2,659	190	2,849	(1,060)	-	(82)	(13)	1,694
Royalties	316	9	325	-	-	-	1	326
Transportation and Blending	1,416	20	1,436	(1,060)	-	-	1	377
Operating	268	80	348	-	-	(82)	(6)	260
Netback	659	81	740	-	-	-	(9)	731
(Gain) Loss on Risk Management	(15)	-	(15)	-	-	-	-	(15)
Operating Margin	674	81	755	-	-	-	(9)	746

(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

Year Ended December 31, 2020 ($ millions)	Basis of Netback Calculation: Foster Creek	Basis of Netback Calculation: Christina Lake	Basis of Netback Calculation: Total Crude Oil	Basis of Netback Calculation: Natural Gas	Adjustments: Condensate	Adjustments: Inventory	Adjustments: Other	Per Consolidated Financial Statements [(4)]: Total Oil Sands
Gross Sales	**1,859**	**2,194**	**4,053**	**-**	**3,452**	**-**	**9**	**7,514**
Royalties	**95**	**235**	**330**	**-**	**-**	**(6)**	**-**	**324**
Transportation and Blending	**667**	**565**	**1,232**	**-**	**3,452**	**(285)**	**-**	**4,399**
Operating	**558**	**551**	**1,109**	**-**	**-**	**(25)**	**10**	**1,094**
Inventory Write-Down (Reversal)	**-**	**-**	**-**			**316**		**316**
Netback	**539**	**843**	**1,382**	**-**	**-**	**-**	**(1)**	**1,381**
(Gain) Loss on Risk Management	**111**	**157**	**268**	**-**	**-**	**-**	**-**	**268**
Operating Margin	**428**	**686**	**1,114**	**-**	**-**	**-**	**(1)**	**1,113**

Year Ended December 31, 2019 ($ millions)	Basis of Netback Calculation: Foster Creek	Basis of Netback Calculation: Christina Lake	Basis of Netback Calculation: Total Crude Oil	Basis of Netback Calculation: Natural Gas	Adjustments: Condensate	Adjustments: Inventory	Adjustments: Other	Per Consolidated Financial Statements [(4)]: Total Oil Sands
Gross Sales	3,295	3,511	6,806	-	4,021	-	11	10,838
Royalties	486	650	1,136	-	-	-	7	1,143
Transportation and Blending	674	458	1,132	-	4,021	-	(1)	5,152
Operating	526	505	1,031	-	-	-	8	1,039
Netback	1,609	1,898	3,507	-	-	-	(3)	3,504
(Gain) Loss on Risk Management	10	13	23	-	-	-	-	23
Operating Margin	1,599	1,885	3,484	-	-	-	(3)	3,481

Year Ended December 31, 2018 ($ millions) [(5)]	Basis of Netback Calculation: Foster Creek	Basis of Netback Calculation: Christina Lake	Basis of Netback Calculation: Total Crude Oil	Basis of Netback Calculation: Natural Gas	Adjustments: Condensate	Adjustments: Inventory	Adjustments: Other	Per Consolidated Financial Statements [(4)]: Total Oil Sands
Gross Sales	2,531	2,489	5,020	1	4,993	-	12	10,026
Royalties	371	102	473	-	-	-	-	473
Transportation and Blending	495	391	886	-	4,993	-	-	5,879
Operating	532	492	1,024	2	-	-	11	1,037
Netback	1,133	1,504	2,637	(1)	-	-	1	2,637
(Gain) Loss on Risk Management	683	868	1,551	-	-	-	-	1,551
Operating Margin	450	636	1,086	(1)	-	-	1	1,086

(4) *Found in Note 1 of the Consolidated Financial Statements.*
(5) *On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.*

Three Months Ended December 31, 2020 ($ millions)	Basis of Netback Calculation: Foster Creek	Basis of Netback Calculation: Christina Lake	Basis of Netback Calculation: Total Crude Oil	Basis of Netback Calculation: Natural Gas	Adjustments: Condensate	Adjustments: Inventory	Adjustments: Other	Per Interim Consolidated Financial Statements [(1)]: Total Oil Sands
Gross Sales	**615**	**756**	**1,371**	**-**	**853**	**-**	**3**	**2,227**
Royalties	**28**	**103**	**131**	**-**	**-**	**-**	**-**	**131**
Transportation and Blending	**144**	**134**	**278**	**-**	**853**	**-**	**-**	**1,131**
Operating	**154**	**152**	**306**	**-**	**-**	**-**	**3**	**309**
Inventory Write-Down (Reversal)	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Netback	**289**	**367**	**656**	**-**	**-**	**-**	**-**	**656**
(Gain) Loss on Risk Management	**15**	**25**	**40**	**-**	**-**	**-**	**-**	**40**
Operating Margin	**274**	**342**	**616**	**-**	**-**	**-**	**-**	**616**

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

Three Months Ended December 31, 2019 ($ millions)	Basis of Netback Calculation				Adjustments			Per Interim Consolidated Financial Statements (1)
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	731	866	1,597	-	1,060	-	2	2,659
Royalties	130	179	309	-	-	-	7	316
Transportation and Blending	207	150	357	-	1,060	-	(1)	1,416
Operating	132	136	268	-	-	-	-	268
Netback	262	401	663	-	-	-	(4)	659
(Gain) Loss on Risk Management	(5)	(10)	(15)	-	-	-	-	(15)
Operating Margin	267	411	678	-	-	-	(4)	674

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

Conventional (2)

Year Ended December 31, 2020 ($ millions)	Basis of Netback Calculation	Adjustments	Per Consolidated Financial Statements(3)
	Total	Other(4)	Total Conventional
Gross Sales	586	49	635
Royalties	40	-	40
Transportation and Blending	81	-	81
Operating	295	23	318
Netback	170	26	196
(Gain) Loss on Risk Management	-	-	-
Operating Margin	170	26	196

Year Ended December 31, 2019 ($ millions)	Basis of Netback Calculation	Adjustments	Per Consolidated Financial Statements(3)
	Total	Other(4)	Total Conventional
Gross Sales	638	53	691
Royalties	30	-	30
Transportation and Blending	82	-	82
Operating	312	25	337
Netback	214	28	242
(Gain) Loss on Risk Management	-	-	-
Operating Margin	214	28	242

Year Ended December 31, 2018 ($ millions) (5)	Basis of Netback Calculation	Adjustments	Per Consolidated Financial Statements(3)
	Total	Other(4)	Total Conventional
Gross Sales	847	57	904
Royalties	73	-	73
Transportation and Blending	86	4	90
Operating	377	26	403
Netback	311	27	338
Operating Margin	285	27	312

(2) This segment was previously referred to as the Deep Basin segment.
(3) Found in Note 1 of the Consolidated Financial Statements.
(4) Reflects operating margin from processing facility.
(5) On January 1, 2019, we adopted IFRS 16 using the modified retrospective approach; therefore, comparative information has not been restated.

Three Months Ended December 31, 2020 ($ millions)	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements(1)
	Total	Other(2)	Total Conventional
Gross Sales	**170**	**14**	**184**
Royalties	**12**	**-**	**12**
Transportation and Blending	**18**	**-**	**18**
Operating	**65**	**7**	**72**
Netback	**75**	**7**	**82**
(Gain) Loss on Risk Management	**-**	**-**	**-**
Operating Margin	**75**	**7**	**82**

Three Months Ended December 31, 2019 ($ millions)	Basis of Netback Calculation	Adjustments	Per Interim Consolidated Financial Statements(1)
	Total	Other(2)	Total Conventional
Gross Sales	179	11	190
Royalties	9	-	9
Transportation and Blending	20	-	20
Operating	74	6	80
Netback	76	5	81
(Gain) Loss on Risk Management	-	-	-
Operating Margin	76	5	81

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) 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		Year Ended December 31		
	December 31, 2020	December 31, 2019	**2020**	2019	2018
Oil Sands					
Foster Creek	**161,108**	153,797	**164,906**	157,770	162,685
Christina Lake	**220,676**	207,399	**221,675**	188,910	204,016
Total Oil Sands Crude Oil	**381,784**	361,196	**386,581**	346,680	366,701
Conventional (3)					
Total Liquids	**24,543**	26,197	**26,646**	26,673	32,454
Natural Gas (MMcf per day)	**369**	403	**379**	424	527
Total Conventional (BOE per day)	**86,123**	93,317	**89,821**	97,423	120,258
Less: Internal Consumption (4) (MMcf per day)	**(344)**	(336)	**(336)**	(320)	(306)
Sales From Continuing Operations (4) (BOE per day)	**410,864**	398,457	**420,456**	390,813	436,163

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