MANAGEMENT'S DISCUSSION AND ANALYSIS

For the year ended December 31, 2021

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", the "Company", or "Cenovus", and means Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) dated February 7, 2022, should be read in conjunction with our December 31, 2021, 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 7, 2022, 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 7, 2022. 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 Energy Inc. ("Husky") became a wholly-owned subsidiary of Cenovus. Husky was subsequently amalgamated with Cenovus on March 31, 2021, (the "amalgamation") under the Canada Business Corporations Act and ceased to make separate filings as a reporting issuer. Unless the context requires otherwise, any reference herein to Husky refers to the business and operations of Husky prior to the amalgamation.

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. Refer to the Abbreviations section for commonly used oil and gas terms.

OVERVIEW OF CENOVUS

We are a Canadian-based integrated energy company headquartered in Calgary, Alberta. Our common shares and common share purchase warrants ("Cenovus Warrants") are listed on the Toronto Stock Exchange ("TSX") and New York Stock Exchange ("NYSE"). Our cumulative redeemable preferred shares series 1, 2, 3, 5 and 7 are listed on the TSX. We are the second largest Canadian-based crude oil and natural gas producer and the second largest Canadian-based refiner and upgrader, with operations in Canada, the United States ("U.S.") and the Asia Pacific region.

Cenovus and Husky Arrangement

On January 1, 2021, Cenovus and Husky closed a transaction to combine the two companies 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 Cenovus Warrants. In addition, all of the issued and outstanding Husky preferred shares were exchanged for Cenovus preferred shares with substantially identical terms.

The Arrangement combined high quality oil sands and heavy oil assets with extensive trading, storage and logistics infrastructure, and downstream assets, which creates 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.

Our upstream operations include oil sands projects in northern Alberta, thermal and conventional crude oil, natural gas and natural gas liquids ("NGLs") projects across Western Canada, crude oil production offshore Newfoundland and Labrador and natural gas and NGLs production offshore China and Indonesia. Our downstream business includes upgrading and refining operations in Canada and the U.S., and retail operations across Canada.

Our operations involve activities across the full value chain to develop, produce, transport and market crude oil and natural gas in Canada and internationally. Our physically integrated upstream and downstream operations help us mitigate the impact of volatility in light-heavy crude oil differentials and contribute to our bottom line by capturing value from crude oil and natural gas production through to the sale of finished products such as transportation fuels.

In 2021, crude oil production from our Oil Sands assets averaged 581.5 thousand barrels per day, which is generally aligned with our downstream crude oil throughput of 508.0 thousand barrels per day. Total upstream production averaged 791.5 thousand barrels of oil equivalent ("BOE") per day. Refer to the Operating and Financial Results section of this MD&A for a summary of Oil Sands production and total upstream production by product type.

Our Strategy

Our strategy is focused on delivering value over the long-term through sustainable, low-cost, diversified and integrated energy leadership. We aim to maximize shareholder value through competitive cost structures and optimizing margins while delivering top-tier safety performance and Environment, Social and Governance ("ESG") leadership. The Company prioritizes Free Funds Flow generation which enables debt reduction, increased shareholder returns through dividend growth and share buybacks, reinvestment in the business and diversification. We believe that maintaining a strong balance sheet will help Cenovus navigate through commodity price volatility. In 2021, we achieved and surpassed our interim Net Debt Target(1) of $10 billion and began purchasing shares under a normal course issuer bid ("NCIB") program. Over the long term, our Net Debt Target is between $6 billion and $8 billion. This aligns with our Net Debt to Adjusted EBITDA Ratio Target(1) of between 1.0 and 1.5 times at the bottom of the cycle, which we see as approximately US$45 per barrel WTI.

On December 8, 2021, we announced our 2022 budget focused on our operational strength, capital discipline and ESG leadership. Free Funds Flow generation will be used to grow shareholder returns and further reduce debt. 2022 guidance dated December 7, 2021, is available on our website at cenovus.com.

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Our Operations

The Company operates through the following reportable segments:

Upstream Segments

- **Oil Sands,** includes the development and production of bitumen and heavy oil in northern Alberta and Saskatchewan. Cenovus's oil sands assets include Foster Creek, Christina Lake, Sunrise (jointly owned with BP Canada Energy Group ULC ("BP Canada") and operated by Cenovus) and Tucker oil sands projects, as well as Lloydminster thermal and Lloydminster conventional heavy oil assets. Cenovus jointly owns and operates pipeline gathering systems and terminals through the equity-accounted investment in Husky Midstream Limited Partnership ("HMLP"). The sale and transportation of Cenovus's production and third-party commodity trading volumes are managed and marketed through access to capacity on third-party pipelines and storage facilities in both Canada and the U.S. to optimize product mix, delivery points, transportation commitments and customer diversification.
- **Conventional,** includes assets rich in NGLs and natural gas within the Elmworth-Wapiti, Kaybob-Edson, Clearwater and Rainbow Lake operating areas in Alberta and British Columbia and interests in numerous natural gas processing facilities. Cenovus's NGLs and natural gas production is marketed and transported with additional third-party commodity trading volumes through access to capacity on third-party pipelines, export terminals and storage facilities, which provides flexibility for market access to optimize product mix, delivery points, transportation commitments and customer diversification.
- **Offshore,** includes offshore operations, exploration and development activities in China and the east coast of Canada, as well as the equity-accounted investment in the Husky-CNOOC Madura Ltd. ("HCML") joint venture in Indonesia.

Downstream Segments

- **Canadian Manufacturing,** includes the owned and operated Lloydminster upgrading and asphalt refining complex which upgrades heavy oil and bitumen into synthetic crude oil, diesel fuel, asphalt and other ancillary products. Cenovus seeks to maximize the value per barrel from its heavy oil and bitumen production through its integrated network of assets. In addition, Cenovus owns and operates the Bruderheim crude-by-rail terminal and two ethanol plants. Cenovus also markets its production and third-party commodity trading volumes of synthetic crude oil, asphalt and ancillary products.
- **U.S. Manufacturing,** includes the refining of crude oil to produce gasoline, diesel, jet fuel, asphalt and other products at the wholly-owned Lima Refinery and Superior Refinery, the jointly-owned Wood River and Borger refineries (jointly owned with operator Phillips 66) and the jointly-owned Toledo Refinery (jointly owned with operator BP Products North America Inc. ("BP")). Cenovus also markets some of its own and third-party volumes of refined petroleum products including gasoline, diesel and jet fuel.
- **Retail**, includes the marketing of our own and third-party volumes of refined petroleum products, including gasoline and diesel, through retail, commercial and bulk petroleum outlets, as well as wholesale channels in Canada.

Corporate and Eliminations

Primarily includes Cenovus-wide costs for general and administrative, financing activities, gains and losses on risk management for corporate related derivative instruments and foreign exchange. Eliminations include adjustments for internal usage of natural gas production between segments, transloading services provided to the Oil Sands segment by the Company's crude-by-rail terminal, crude oil production used as feedstock by the Canadian Manufacturing and U.S. Manufacturing segments, and diesel production in the Canadian Manufacturing segment sold to the Retail segment. Eliminations are recorded based on current market prices.

To conform to the presentation adopted for the current period's operating segments, market optimization activities, unrealized gains and losses on risk management and results previously reported under the Refining and Marketing segment have been reclassified.

The Arrangement was accounted for using the acquisition method pursuant to IFRS 3, "*Business Combinations*". Under the acquisition method, assets and liabilities are measured at their estimated fair value on the date of acquisition with the exception of income tax, stock-based compensation, lease liabilities and right-of-use ("ROU") assets. The total consideration was allocated to the tangible and intangible assets acquired and liabilities assumed. Comparative figures in this MD&A include Cenovus results prior to the closing of the Arrangement on January 1, 2021, and does not reflect any historical data from Husky.

The final purchase price allocation is based on Management's best estimate of fair value and has been retrospectively adjusted to reflect new information obtained between January 1, 2021, and December 31, 2021, about the conditions that existed at the date of the Arrangement. Total consideration, including non-controlling interest, was $6.9 billion. The fair value of the total identifiable net assets was $5.6 billion, resulting in $1.3 billion of goodwill generated from the transaction.

YEAR IN REVIEW

Cenovus completed a very successful first year as a combined company following the closure of the Arrangement on January 1, 2021. We focused on health and safety as our top priority while maintaining our low operating and capital cost structures. The strong operational performance of our integrated asset base and the improving commodity price environment drove solid financial results. We significantly reduced our Net Debt and achieved our planned annual run rate synergy targets. We reintroduced our common share dividend in the first quarter and doubled it in the fourth quarter. In addition, we commenced a NCIB to further increase returns to shareholders. We also optimized our asset portfolio through numerous dispositions and restructured our interests in the Atlantic region.

Summary of Annual Results

($ millions, except where indicated)	**2021**	**Percent Change**	2020	Percent Change	2019
Production Volumes [1] (MBOE/d)	**791.5**	**68**	471.7	4	451.7
Crude Throughput [2] (Mbbls/d)	**508.0**	**173**	185.9	(16)	221.3
Revenues [3]	**46,357**	**242**	13,543	(34)	20,542
Netback [4] ($/bbl)	**37.04**	**267**	10.09	(61)	26.02
Operating Margin [4]	**9,373**	**918**	921	(79)	4,460
Cash From (Used in) Operating Activities	**5,919**	**2,068**	273	(92)	3,285
Adjusted Funds Flow [4][5]	**7,248**	**6,095**	117	(97)	3,670
Capital Investment	**2,563**	**205**	841	(28)	1,176
Free Funds Flow [4][5]	**4,685**	**747**	(724)	(129)	2,494
Net Earnings (Loss) [6]	**587**	**125**	(2,379)	(208)	2,194
Per Share - basic and diluted ($)	**0.27**	**114**	(1.94)	(209)	1.78
Total Assets	**54,104**	**65**	32,770	(7)	35,173
Total Long-Term Liabilities [4]	**23,191**	**69**	13,704	(2)	13,991
Long-Term Debt, Including Current Portion [7]	**12,385**	**66**	7,441	11	6,699
Net Debt [8][9]	**9,591**	**34**	7,184	10	6,513
Net Debt to Capitalization Ratio [9] (percent)	**29**	**(3)**	30	20	25
Net Debt to Adjusted EBITDA Ratio [9] (times)	**1.2**	**(90)**	11.9	644	1.6
Cash Dividends					
Common Shares	**176**	**129**	77	(70)	260
Per Common Share ($)	**0.0875**	**40**	0.0625	(71)	0.2125
Preferred Shares	**34**	**—**	—	—	—

(1) Refer to the Operating and Financial Results section of this MD&A for a summary of total upstream production by product type.
(2) Represents Cenovus's net interest in refining operations. The comparative periods have been restated to Cenovus's net interest.
(3) Comparative figures have been re-presented for a portion of inventory write-downs reclassified to royalties. Prior period results have been adjusted for the change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Adjustments to the Consolidated Statements of Earnings (Loss) section in this MD&A.
(4) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(5) Comparative figures have been restated to conform with the definition in this MD&A.
(6) Net earnings (loss) for the years ended December 31, 2021, 2020 and 2019 is equal to net earnings (loss) from continuing operations.
(7) The current portion of long-term debt was $nil as at December 31, 2021, 2020 and 2019.
(8) At December 31, 2021, includes long-term debt, including current portion, and short-term borrowings assumed at fair value of $6.6 billion as part of the Arrangement, net of cash and cash equivalents assumed at fair value of $735 million.
(9) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Operationally, items under Management's control performed very well:

- We delivered safe operations.
- Upstream production averaged 791.5 thousand BOE per day in 2021, an increase of 319.8 thousand BOE per day compared with 2020. Assets acquired in the Arrangement averaged 290.4 thousand BOE per day in 2021. See the Operating and Financial Results section of this MD&A for a summary of upstream production by product type.
- Downstream crude throughput averaged 508.0 thousand barrels per day in 2021, an increase of 322.1 thousand barrels per day compared with 2020. Assets acquired in the Arrangement averaged 303.3 thousand barrels per day of crude throughput in 2021.
- We applied learnings from Cenovus's operating model at our Lloydminster thermal assets which resulted in new production records and reduced steam-oil-ratios ("SORs") at other Oil Sands assets acquired in the Arrangement.
- Achieved single-day production records at Foster Creek and Christina Lake.

We generated revenue of $46.4 billion and cash from operating activities of $5.9 billion. Adjusted Funds Flow was $7.2 billion and capital investment was $2.6 billion, resulting in Free Funds Flow of $4.7 billion. Operating Margin was $9.4 billion in 2021 compared with $921 million in 2020, primarily due to increased revenue from higher average realized crude oil, NGLs and natural gas sales prices, higher market crack spreads, sales volumes from assets acquired in the Arrangement and increased sales volumes from Foster Creek and Christina Lake.

We strengthened our balance sheet:

- Reduced our long-term debt by $1.7 billion and Net Debt by $3.5 billion following the closing of the Arrangement and surpassed our interim Net Debt Target of $10 billion, positioning us to increase our allocation of Free Funds Flow towards shareholder returns.
- Issued US$1.25 billion of 10-year and 30-year notes, used the proceeds and cash on hand to repurchase approximately US$2.2 billion in principal of our outstanding notes. These transactions will generate substantial interest expense savings going forward and extended the maturity profile of our debt.
- Achieved credit rating upgrades throughout the year.
- On January 10, 2022, we announced we are repurchasing US$384 million in principal of outstanding notes due in 2023 and 2024.

We achieved our planned total of $1.2 billion annual run-rate synergies by the end of 2021. In 2021, we incurred $402 million of Total Integration Costs(1), including capital of $53 million.

We optimized our asset portfolio:

- Announced dispositions with cash proceeds totaling $1.9 billion, of which approximately $430 million were received in 2021:
    - In May, we sold our gross-overriding royalty ("GORR") interest in the Marten Hills area of Alberta for cash proceeds of $102 million.
    - In October, we sold assets from the Conventional segment in the East Clearwater and Kaybob areas of Alberta for combined gross proceeds of $103 million.
    - In October, we closed our bought deal secondary offering of an aggregate of 50 million common shares of Headwater Exploration Inc. ("Headwater") for cash gross proceeds of $228 million.
    - On November 30, we announced an agreement to sell assets within the Conventional segment, primarily our Montney assets, in the Wembley area for cash proceeds of approximately $238 million. The sale is expected to close in the first quarter of 2022.
    - On November 30, we announced agreements to sell 337 gas stations from the Retail segment for aggregate cash proceeds of approximately $420 million. The sales are expected to close in mid-2022. We are retaining our commercial fuels business, which includes 167 cardlock, bulkplant and travel centre locations.
    - On December 16, we announced an agreement to sell our Tucker asset within the Oil Sands segment for gross cash proceeds of $800 million. The sale closed on January 31, 2022.
- De-risked our Atlantic business by restructuring our interests.
    - We closed an agreement with our partners in the Terra Nova field to increase our working interest. The Terra Nova Asset Life Extension ("ALE") project is proceeding, extending the life of the field to 2033. Production, which has been suspended since 2019, is expected to resume before the end of 2022.
    - We entered into an agreement with Suncor in the White Rose field to decrease our working interest. The working interest restructuring will not occur if the project does not proceed.

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

We increased our returns to shareholders:

- Commenced a NCIB for the purchase of up to 146.5 million of the Company's common shares. In 2021, Cenovus purchased and cancelled 17 million common shares for $265 million. From January 1, 2022 to February 7, 2022, Cenovus purchased an additional 9 million common shares for $160 million.
- Doubled our dividend to $0.035 per common share for the fourth quarter, compared with $0.0175 per common share in each of the first three quarters.

We prioritize ongoing ESG leadership and integration of sustainability considerations into our business decisions. In June, we announced the Oil Sands Pathways to Net Zero initiative, an alliance of peers working collectively with the federal and provincial governments with a goal to achieve net zero greenhouse gas ("GHG") emissions from oil sands operations by 2050. In December, we released ambitious targets for climate and GHG emissions, water stewardship, biodiversity, Indigenous reconciliation, and inclusion and diversity.

Cenovus remains committed to the health and safety of its workforce and the public while providing essential services. Physical distancing measures and other protocols continue to be in place 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. Work-from-home measures remained in place through the majority of 2021 and continue to be in place for all non-essential staff at our combined offices and worksites in Alberta, Saskatchewan and Manitoba, pending further review. The full scope of our operations 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.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results - Upstream

	2021	Percent Change	2020	Percent Change	2019
Upstream Production Volumes by Segment					
Oil Sands (Mbbls/d)					
Foster Creek	179.9	10	163.2	2	159.6
Christina Lake	236.8	8	218.5	12	194.7
Sunrise [1]	25.9	—	—	—	—
Lloydminster Thermal	97.7	—	—	—	—
Tucker [2]	21.0	—	—	—	—
Lloydminster Conventional Heavy Oil [3]	20.2	—	—	—	—
Total Oil Sands Crude Oil [4]	581.5	52	381.7	8	354.3
Oil Sands Natural Gas [5] (MMcf/d)	12.6	—	—	—	—
Conventional [6] (MBOE/d)	133.6	49	89.9	(8)	97.4
Offshore (MBOE/d)					
Asia Pacific [7][8]	60.3	—	—	—	—
Atlantic [9]	14.1	—	—	—	—
Offshore Total	74.4	—	—	—	—
Total Production Volumes (MBOE/d)	791.5	68	471.7	4	451.7
Upstream Production Volumes by Product					
Bitumen (Mbbls/d)	561.3	47	381.7	8	354.3
Heavy Crude Oil [3] (Mbbls/d)	20.2	648	2.7	—	—
Light Crude Oil (Mbbls/d)	22.5	400	4.5	(8)	4.9
NGLs (Mbbls/d)	38.3	96	19.5	(11)	21.8
Conventional Natural Gas (MMcf/d)	895.5	136	379.0	(11)	424.5
Total Production Volumes (MBOE/d)	791.5	68	471.7	4	451.7
Total Upstream Sales Volumes [10] (MBOE/d)	700.8	67	420.5	8	390.8
Oil and Gas Reserves (MMBOE)					
Total Proved	6,077	21	5,030	(1)	5,103
Probable	2,201	33	1,656	(6)	1,768
Total Proved Plus Probable	8,278	24	6,686	(3)	6,871

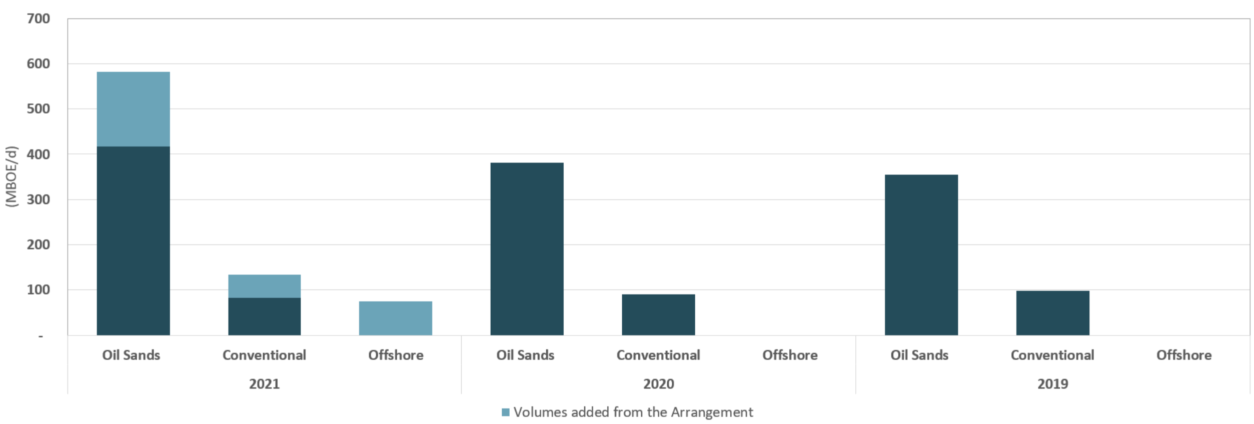
(1) Represents Cenovus's 50 percent interest in the Sunrise operations.
(2) Sale of the Tucker asset closed on January 31, 2022.
(3) The Lloydminster conventional heavy oil area was previously referred to as Lloydminster cold and enhanced oil recovery ("EOR"). During the year ended December 31, 2021, production comprised of medium crude oil in this area was reclassified to heavy crude oil.
(4) Oil Sands production is comprised of bitumen except for Lloydminster Conventional Heavy Oil, which includes heavy crude oil.
(5) Conventional natural gas product type.
(6) Refer to the Conventional Operating Results section of this MD&A for a summary of Conventional production by product type.
(7) Reported production volumes reflect Cenovus's 40 percent interest in the Madura-BD gas project. Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.
(8) Refer to the Asia Pacific Operating Results section of this MD&A for a summary of Asia Pacific production by product type.
(9) Refer to the Atlantic Operating Results section of this MD&A for a summary of Atlantic production by product type.
(10) Total upstream sales volumes exclude natural gas volumes used for internal consumption by the Oil Sands segment of 517 MMcf per day for the year ended December 31, 2021 (336 MMcf per day for the year ended December 31, 2020).

Selected Operating Results - Downstream

	2021	Percent Change	2020	Percent Change	2019
Downstream Manufacturing Crude Throughput					
Canadian Manufacturing (Mbbls/d)					
Lloydminster Upgrader	79.0	—	—	—	—
Lloydminster Refinery	27.5	—	—	—	—
Canadian Manufacturing Total	106.5	—	—	—	—
U.S. Manufacturing (Mbbls/d)					
Lima Refinery	126.9	—	—	—	—
Toledo Refinery [1]	69.9	—	—	—	—
Wood River and Borger Refineries [1]	204.7	10	185.9	(16)	221.3
U.S. Manufacturing Total	401.5	116	185.9	(16)	221.3
Total Throughput (Mbbls/d)	508.0	173	185.9	(16)	221.3
Retail [2] **(millions of litres/d)**					
Fuel sales, including wholesale	6.9	—	—	—	—

(1) Represents Cenovus's 50 percent interest in the Wood River, Borger and Toledo operations.
(2) Sale of a portion of our Retail assets expected to close in mid-2022.

Upstream Production Volumes



In 2021, our upstream assets performed well. Oil Sands production increased 199.8 thousand barrels per day compared with 2020 due to 164.8 thousand barrels per day from assets acquired in the Arrangement and higher production at Foster Creek and Christina Lake. The increases at Foster Creek and Christina Lake were due to new wells coming online combined with our decision to operate at reduced levels at Christina Lake in 2020 in response to market conditions. The increase was partially offset by a planned turnaround and operational outages at Foster Creek in the second quarter of 2021. Production steadily increased during the year and we achieved several single-day production records at Foster Creek, Christina Lake and our Lloydminster thermal assets. Our Lloydminster thermal assets performed well as we applied our operating strategy and production and well delivery techniques to the acquired assets.

Conventional production increased 43.8 thousand BOE per day primarily due to volumes from assets acquired in the Arrangement, which produced 51.2 thousand BOE per day during the year. The increase was partially offset by the disposition of assets in the East Clearwater and Kaybob areas in the second half of 2021. Prior to closing, these assets were producing approximately 11.0 thousand BOE per day.

Offshore production was relatively consistent throughout the year and is entirely from assets acquired in the Arrangement.

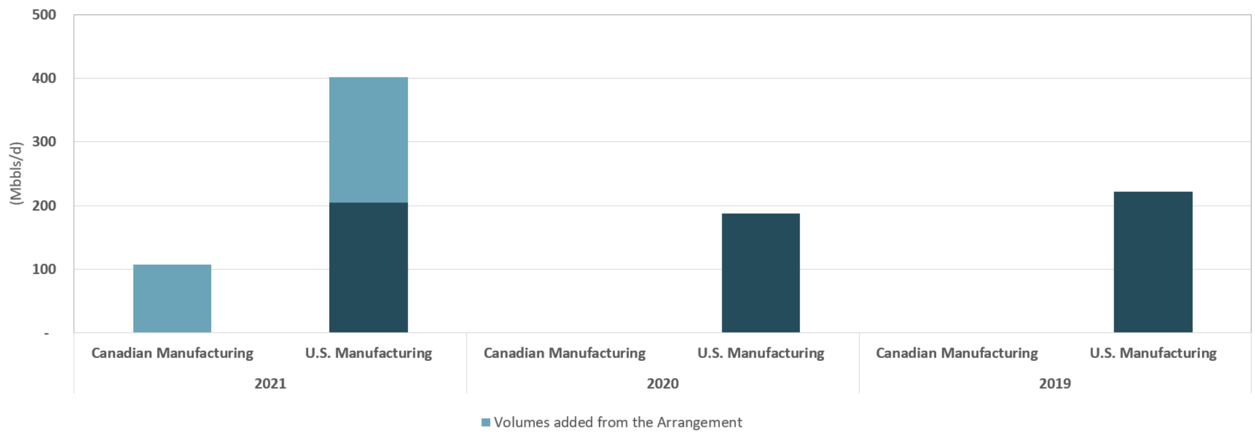
Oil and Gas Reserves

Based on our reserves reports prepared by independent qualified reserves evaluators ("IQREs"), at the end of 2021 total proved reserves and total proved plus probable reserves were approximately 6.1 billion BOE and 8.3 billion BOE, respectively, increasing 21 percent and 24 percent, respectively, compared with 2020.

Additional information about our reserves, including a summary of total upstream production by product type, is included in the Oil and Gas Reserves section of this MD&A.

Downstream Manufacturing

Crude Throughput by Segment



U.S. Manufacturing throughput increased 215.6 thousand barrels per day compared with 2020. Throughput increased due to 196.8 thousand barrels per day from assets acquired in the Arrangement and higher throughput at the Wood River and Borger refineries as the market for refined products improved.

At the Wood River and Borger refineries, throughput was temporarily impacted by unplanned outages in 2021. We maintained high throughput rates at the Lima Refinery in the first nine months of 2021 before completing a turnaround in October and November and encountering subsequent unplanned equipment outages. The refinery returned to normal operations towards the end of January 2022. At the Toledo Refinery, throughput was optimized in-line with market demand in 2021.

In the Canadian Manufacturing segment, the Lloydminster Upgrader and Lloydminster Refinery, both of which were acquired in the Arrangement, ran at or near capacity throughout 2021.

Selected Consolidated Financial Results

Operating Margin

Operating Margin is a non-GAAP financial measure 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.

($ millions)	**2021**	2020 [(1)]	2019 [(1)]
Gross Sales [(2)]	**54,517**	14,523	22,404
Less: Royalties	**2,454**	371	1,173
Revenues	**52,063**	14,152	21,231
Expenses			
Purchased Product [(2)]	**28,369**	5,959	9,206
Transportation and Blending	**7,930**	4,764	5,234
Operating Expenses	**5,499**	2,261	2,324
Realized (Gain) Loss on Risk Management Activities	**892**	247	7
Operating Margin [(3)]	**9,373**	921	4,460

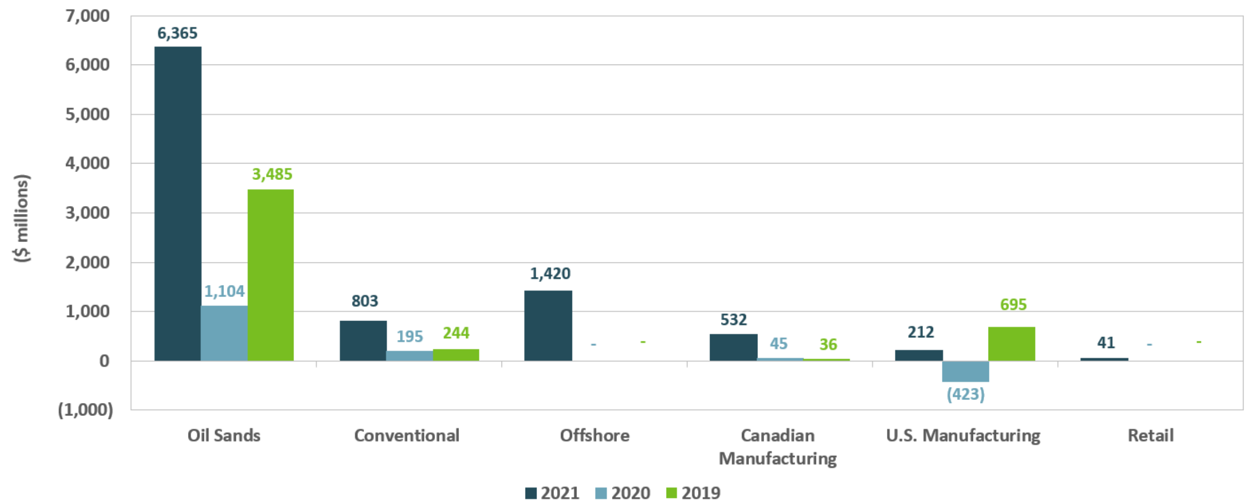
(1) Inventory write-downs prior to January 1, 2021, have been reclassified to royalties, purchased product, transportation and blending or operating expenses to conform with the current presentation of inventory write-downs.

(2) Prior period results have been adjusted for the change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Adjustments to the Consolidated Statements of Earnings (Loss) section in this MD&A.

(3) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

Operating Margin by Segment

Year Ended December 31, 2021



Operating Margin increased in 2021, primarily due to:

- Higher average crude oil, NGLs and natural gas sales prices resulting from higher benchmark pricing.
- Upstream and refined products sales volumes from assets acquired in the Arrangement.
- Increased sales volumes at Foster Creek and Christina Lake.
- Higher market crack spreads in the U.S. Manufacturing segment.

These increases in Operating Margin were partially offset by:

- Increased blending costs due to higher condensate prices and volumes.
- Higher royalties, transportation and blending costs, and operating expenses from assets acquired in the Arrangement.
- Increased fuel costs in the Oil Sands segment due to high natural gas benchmark pricing.
- Higher realized risk management losses due to the settlement of benchmark prices relative to our risk management contract prices.
- Increased Renewable Identification Numbers ("RINs") costs impacting our U.S. Manufacturing segment.

Cash From (Used in) Operating Activities and Adjusted Funds Flow

Adjusted Funds Flow is a non-GAAP financial 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.

($ millions)	**2021**	2020	2019
Cash From (Used in) Operating Activities	**5,919**	273	3,285
(Add) Deduct:			
Settlement of Decommissioning Liabilities	**(102)**	(42)	(52)
Net Change in Non-Cash Working Capital	**(1,227)**	198	(333)
Adjusted Funds Flow	**7,248**	117	3,670

Cash From Operating Activities and Adjusted Funds Flow were significantly higher in 2021 due to:

- Increased Operating Margin, as discussed above.
- Distributions of $137 million received from equity-accounted affiliates.
- Business interruption insurance proceeds of $120 million related to the Superior Refinery.

The increases were partially offset by:

- Integration costs of $349 million.
- Higher finance costs due to interest expense on long-term debt assumed as part of the Arrangement.
- Increased general and administrative expenses due to a larger workforce resulting from the Arrangement and provisions related to reaching our synergy-focused incentive plan.
- Contingent payment of $242 million, of which $175 million was recognized as a reduction to Cash from Operating Activities and Adjusted Funds Flow in 2021.

- Long-term incentives of $111 million paid in the first quarter of 2021, related to the accelerated payout to our employees in connection with the Arrangement.

The change in non-cash working capital in 2021 was primarily due to an increase in inventories and accounts receivable, partially offset by an increase in accounts payable on December 31, 2021, compared with December 31, 2020.

In 2021, the increase in accounts receivable was primarily due to higher crude oil pricing and sales volumes from the Oil Sands segment and higher refined product pricing in the U.S. Manufacturing segment. The increases were partially offset by timing of cash receipts from customers and the receipt of insurance proceeds from the Superior Refinery rebuild project. The increase in inventory compared with 2020 was primarily due to higher volumes from increased access to transportation and storage capacity and the addition of facilities in the Canadian Manufacturing and U.S. Manufacturing segment as a result of the Arrangement. The increase in accounts payable was primarily due to higher condensate prices in the Oil Sands segment, higher accrued royalties payable, long-term incentives payable, accrued contingent liability payable and income taxes payable. The increases were partially offset by the settlement of the integration costs, long-term incentive costs paid to Cenovus employees and the payment of long-term incentives liabilities assumed as part of the Arrangement.

Net Earnings (Loss)

($ millions)	2021 vs. 2020	2020 vs. 2019
Net Earnings (Loss), Comparative Year	**(2,379)**	**2,194**
Increase (Decrease) due to:		
Operating Margin	**8,452**	**(3,539)**
Corporate and Eliminations:		
Unrealized Foreign Exchange Gain (Loss)	**181**	**(696)**
Re-measurement of Contingent Payment	**(655)**	**244**
Integration Costs	**(320)**	**(29)**
General and Administrative	**(557)**	**39**
Finance Costs	**(546)**	**(25)**
Other [1]	**303**	**566**
Unrealized Risk Management Gain (Loss)	**36**	**37**
Depreciation, Depletion and Amortization	**(2,422)**	**(1,215)**
Exploration Expense	**73**	**(9)**
Income Tax Recovery (Expense)	**(1,579)**	**54**
Net Earnings (Loss), Current Year	**587**	**(2,379)**

(1) Includes interest income, realized foreign exchange (gains) losses, (gain) loss on divestiture of assets, other (income) loss, net, share of income (loss) from equity-accounted affiliates, and Corporate and Eliminations revenues, purchased product, transportation and blending, operating expenses and (gain) loss on risk management.

Net earnings in 2021 improved significantly compared with the net loss in 2020 due to:

- Higher Operating Margin, as discussed above.
- Impairment charges of $1.1 billion in the Conventional and U.S. Manufacturing segments in 2020.
- Impairment reversals of $378 million in the Conventional segment in 2021, due to improved forward commodity prices.
- Higher other income due to business interruption insurance proceeds of $120 million related to the Superior Refinery and a settlement of a legal claim in favour of Cenovus in 2021, whereas we recognized a $100 million loss on the Keystone XL pipeline project in the fourth quarter of 2020.
- Increased unrealized foreign exchange gains.
- Higher gains on divestiture of assets in 2021, primarily related to the Marten Hills common share and GORR sales.

The increase was partially offset by:

- Income tax expense compared with a recovery in 2020.
- A loss on re-measurement of contingent payment of $575 million (2020 – $80 million gain).
- Integration costs of $349 million.
- Impairment charges of $1.9 billion in the U.S. Manufacturing segment in the fourth quarter of 2021 due to the forward prices impacting refined product margins.
- Realized foreign exchange losses on the repurchase of U.S. dollar denominated debt in 2021.
- Provisions related to reaching our synergy-focused incentive plan.
- Net premiums of $121 million on the redemption of long-term debt (2020 – $25 million net discount).
- Increased general and administrative costs, finance expenses, and depreciation, depletion and amortization ("DD&A") expense as a result of the Arrangement.

Net Debt

As at ($ millions)	December 31, 2021	January 1, 2021 (1)	December 31, 2020	December 31, 2019
Short-Term Borrowings	**79**	161	121	—
Current Portion of Long-Term Debt	**—**	—	—	—
Long-Term Debt	**12,385**	14,043	7,441	6,699
Total Debt (2)	**12,464**	14,204	7,562	6,699
Less: Cash and Cash Equivalents	**(2,873)**	(1,113)	(378)	(186)
Net Debt	**9,591**	13,091	7,184	6,513

(1) Includes balances at December 31, 2020, plus the fair value of amounts assumed from the Arrangement.
(2) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

Net Debt on January 1, 2021, was $13.1 billion, including the fair value of $5.9 billion assumed from the Arrangement. Since the Arrangement, we have reduced our long-term debt by $1.7 billion and Net Debt by $3.5 billion.

Capital Investment (1) (2)

($ millions)	2021	2020	2019
Upstream			
Oil Sands	**1,019**	427	656
Conventional	**222**	78	103
Offshore			
Asia Pacific	**21**	—	—
Atlantic	**154**	—	—
	1,416	505	759
Downstream			
Canadian Manufacturing	**37**	33	52
U.S. Manufacturing	**995**	243	228
Retail	**31**	—	—
	1,063	276	280
Corporate and Eliminations	**84**	60	137
Capital Investment	**2,563**	841	1,176

(1) Includes expenditures on PP&E, E&E assets and assets held for sale.
(2) Prior periods have been reclassified to conform with current period's operating segments.

Oil Sands capital investment in 2021 was primarily focused on sustaining production at Christina Lake, Foster Creek and the Lloydminster thermal assets.

Conventional capital investment focused on short cycle, high return development wells which are expected to improve underlying cost structures through volume enhancement and offset natural declines.

Offshore capital investment in 2021 was primarily preservation capital for the West White Rose project in the Atlantic region. Major construction on the West White Rose project was suspended in March of 2020 and the project remains under review while we evaluate options with our partners.

U.S. Manufacturing capital investment focused primarily on the Superior Refinery rebuild, combined with refining reliability, maintenance and yield optimization projects at the Wood River and Borger refineries, and maintenance projects at the Toledo Refinery.

Drilling Activity

	Gross Stratigraphic Test Wells and Observation Wells			Gross Production Wells [1]		
	2021	2020	2019	**2021**	2020	2019
Foster Creek	**17**	38	14	**6**	—	—
Christina Lake [2]	**25**	117	30	**18**	—	11
Sunrise	**—**	—	—	**2**	—	—
Lloydminster Thermal	**115**	—	—	**46**	—	—
Lloydminster Conventional Heavy Oil	**15**	—	—	**3**	—	—
Other [3]	**17**	—	14	**—**	—	—
	189	155	58	**75**	—	11

(1) Steam-assisted gravity drainage ("SAGD") well pairs in the Oil Sands segment are counted as a single producing well.
(2) Includes Narrows Lake.
(3) Includes new resource plays.

Stratigraphic test wells were drilled to help identify well pad locations for sustaining wells and to further progress the evaluation of other assets. Observation wells were drilled to gather information and monitor reservoir conditions.

	2021			2020			2019		
(net wells, unless otherwise stated)	**Drilled**	**Completed**	**Tied-in**	Drilled	Completed	Tied-in	Drilled	Completed	Tied-in
Conventional	**27**	**19**	**18**	6	1	3	11	2	3

In the Offshore segment, we drilled a planned exploration well in China in October 2021.

Future Capital Investment

Future Capital Investment is a specified financial measure. See the Specified Financial Measures Advisory of this MD&A. Our guidance dated December 7, 2021, is available on our website at cenovus.com.

Our Oil Sands capital investment for 2022 is forecast to be between $1.4 billion and $1.6 billion. The increase from 2021 is primarily related to additional sustaining capital activities. Our Oil Sands production is expected to range between 570.0 thousand barrels per day and 630.0 thousand barrels per day. Oil Sands production guidance is not adjusted for the Tucker asset sale which closed on January 31, 2022.

Our Conventional capital investment for 2022 is forecast to be between $150 million and $200 million, focused on sustaining drilling programs. Our Conventional production is expected to range between 118.0 thousand BOE per day and 134.0 thousand BOE per day.

Our Offshore capital investment for 2022 is expected to be between $200 million and $250 million. This capital spend is primarily directed towards the Terra Nova ALE project and preservation capital for the West White Rose project. Production from our Offshore segment is expected to range between 64.0 thousand BOE per day and 76.0 thousand BOE per day.

In 2022, we plan to invest between $850 million and $950 million in our downstream segments focused on refining operations and reliability and a debottlenecking project at the Lloydminster Refinery to increase throughput capacity. Downstream capital investment includes between $200 million and $250 million for the Superior Refinery rebuild project. The rebuild project is expected to further enhance our heavy oil value chain integration while further reducing the Company's exposure to WTI-WCS location differentials. Downstream throughput is expected to be in the range of 530.0 thousand barrels per day to 580.0 thousand barrels per day.

We expect to invest between $50 million and $70 million of corporate capital across the Company.

Further information on the changes in our financial and operating results can be found in the Reportable Segments section of this MD&A. 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.

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 and Chinese Yuan ("RMB")/Canadian dollar exchange rates. The following table shows selected market benchmark prices and average exchange rates to assist in understanding our financial results.

Selected Benchmark Prices and Exchange Rates (1)

(Average US$/bbl, unless otherwise indicated)	**2021**	Percent Change	2020	2019	**Q4 2021**	Q4 2020
Brent (2)	**70.73**	**70**	41.67	64.18	**79.73**	44.22
WTI	**67.91**	**72**	39.40	57.03	**77.19**	42.66
Differential Brent-WTI	**2.82**	**24**	2.27	7.15	**2.54**	1.56
WCS at Hardisty	**54.87**	**105**	26.80	44.27	**62.55**	33.36
Differential WTI-WCS	**13.04**	**3**	12.60	12.76	**14.64**	9.30
WCS (C$/bbl)	**68.73**	**93**	35.59	58.77	**78.71**	43.41
WCS at Nederland	**64.09**	**79**	35.86	55.56	**71.62**	40.36
Differential WTI-WCS at Nederland	**3.82**	**8**	3.54	1.47	**5.57**	2.30
Condensate (C5 @ Edmonton)	**68.20**	**84**	37.16	52.86	**79.13**	42.54
Differential WTI-Condensate (Premium)/Discount	**(0.29)**	**(113)**	2.24	4.17	**(1.94)**	0.12
Differential WCS-Condensate (Premium)/Discount	**(13.33)**	**29**	(10.36)	(8.59)	**(16.58)**	(9.18)
Average (C$/bbl)	**85.47**	**73**	49.44	70.15	**99.64**	55.36
Synthetic @ Edmonton	**66.28**	**83**	36.25	56.45	**75.40**	39.60
WTI-Synthetic (Premium)/Discount Differential	**1.63**	**(48)**	3.15	0.58	**1.79**	3.06
Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**85.07**	**88**	45.24	70.55	**91.84**	47.31
Chicago Ultra-low Sulphur Diesel ("ULSD")	**86.37**	**72**	50.08	77.97	**96.53**	54.21
Refining Benchmarks						
Chicago 3-2-1 Crack Spread (3)	**17.54**	**133**	7.54	16.00	**16.06**	7.05
Group 3 3-2-1 Crack Spread (3)	**17.82**	**106**	8.67	16.67	**15.82**	7.57
RINs	**6.76**	**173**	2.48	1.21	**6.11**	3.48
Natural Gas Prices						
AECO (C$/Mcf)	**3.56**	**59**	2.24	1.62	**4.94**	2.77
NYMEX (US$/Mcf)	**3.84**	**85**	2.08	2.63	**5.83**	2.66
Foreign Exchange Rate						
US$ per C$1 - Average	**0.798**	**7**	0.746	0.754	**0.794**	0.768
US$ per C$1 - End of Period	**0.789**	**1**	0.785	0.770	**0.789**	0.785
RMB per C$1 - Average	**5.147**	**—**	5.147	5.207	**5.073**	5.084

(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) Calendar month average of settled prices for Dated Brent.
(3) 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.

Crude Oil and Condensate Benchmarks

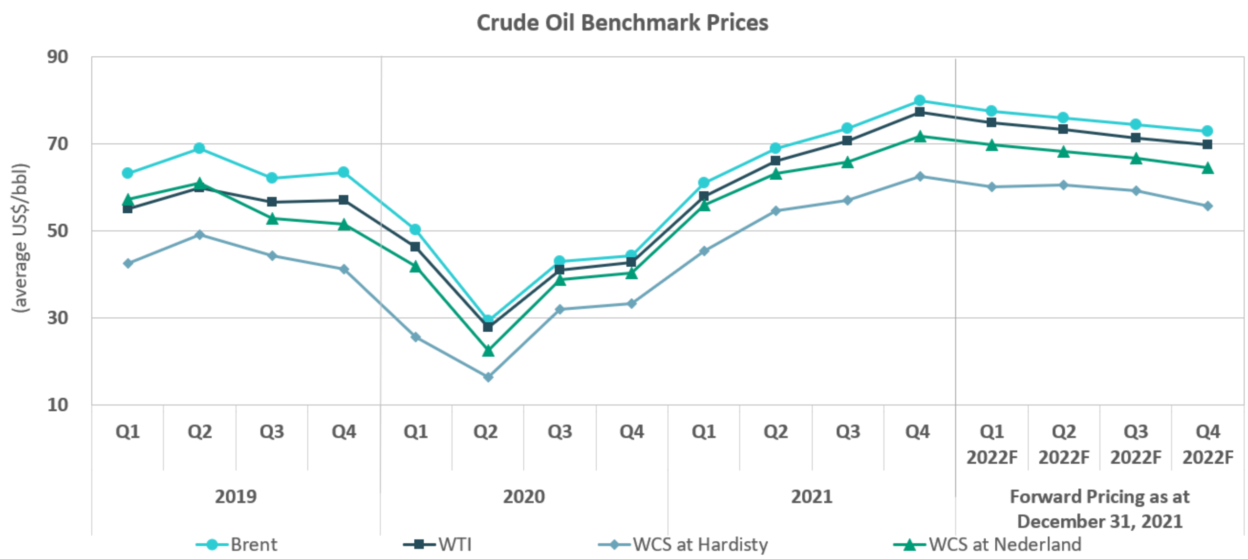
In 2021, Brent and WTI crude oil benchmarks improved significantly compared to 2020 as demand for crude oil outpaced supply due to increased global crude oil demand amid roll out efforts of COVID-19 vaccines, economic recovery and easing of restrictions. The Organization of the Petroleum Exporting Countries ("OPEC") and a group of 10 non-OPEC members (collectively, "OPEC+") continued to support global prices despite the gradual easing of production quotas that began in the second quarter. The price received for our Atlantic crude oil and Asia Pacific NGLs is primarily driven by the price of Brent.

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 2021, the Brent-WTI differential remained narrow compared to 2020 due to continued low crude oil exports 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 2021, the average WTI-WCS differential remained narrow due to takeaway capacity from the Western Canadian Sedimentary Basin ("WCSB").

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 prices were strong in 2021 compared to 2020 consistent with increasing crude oil prices globally, as refiners increased crude runs to adjust to increased demand for products. In the second half of 2021, the WTI-WCS at Nederland differential widened compared with 2020, mainly attributed to high coking utilization in the USGC and the gradual return of some OPEC+ medium and heavy oil barrels into the market.

We upgrade heavy crude oil and bitumen into a sweet synthetic crude oil, the Husky Synthetic Blend ("HSB"), at the Lloydminster Upgrader. The price realized for HSB is primarily driven by the price of WTI and by the supply and demand of sweet synthetic crude oil from Western Canada, which influences the WTI-Synthetic differential.



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 23 percent to 31 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 Edmonton condensate benchmark prices were at a slight premium relative to WTI in 2021. The differential has narrowed compared with 2020 as a result of higher oil sands production leading to an increase in blending requirements.

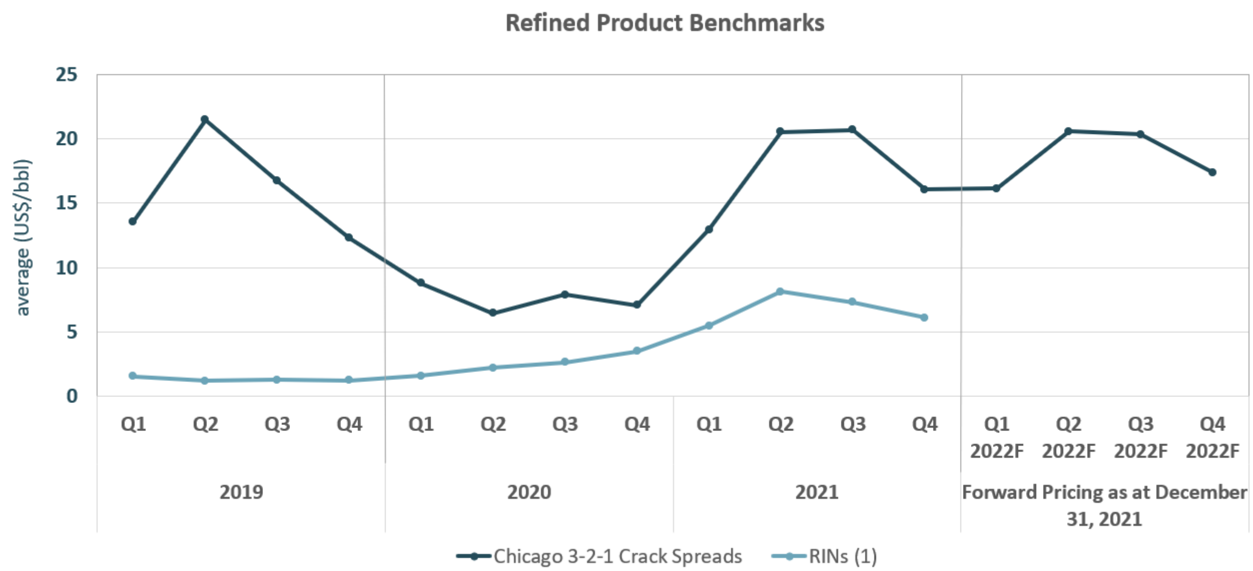
Refining Benchmarks

RUL and 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.

The Chicago 3-2-1 market crack spread reflects the market for our Toledo, Lima and Wood River refineries. The Group 3, 3-2-1 market crack spread, reflects the market for our Borger Refinery.

Average Chicago refined product prices increased in 2021 compared with 2020, due to a combination of the higher cost of RINs as a result of a tight biofuel market and uncertainty around policies that drive RINs demand, as well as higher refined product demand due to the deployment of COVID-19 vaccines, easing of restrictions and increasing travel and economic activity. Recovering refined product demand resulted in lower inventory levels which increased market crack spreads. As North American refining crack spreads are expressed on a WTI basis, while refined products are generally set by global prices, the strength of refining market crack spreads in the U.S. Midwest and Midcontinent will reflect the differential between Brent and WTI benchmark prices.

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



(1) There are no forward prices for RINs.

Natural Gas Benchmarks

Average NYMEX natural gas prices increased significantly in 2021 compared to 2020 as hot summer weather, a rebound in U.S. domestic demand, record liquified natural gas exports coupled with a muted supply response and strong global pricing, supported the market. Average AECO prices improved alongside the NYMEX benchmark. The differential between AECO and NYMEX widened in 2021 as a function of increased supply. The price received for our Asia Pacific natural gas production is largely based on long-term contracts.

Foreign Exchange Benchmarks

A substantial amount of 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 revenue. In addition to our revenues being denominated in U.S. dollars, a significant portion of our long-term debt is also U.S. dollar denominated. As the Canadian dollar weakens, our U.S. dollar debt gives rise to unrealized foreign exchange losses when translated to Canadian dollars. In addition, changes in foreign exchange rates impact the translation of U.S. and Asia Pacific operations.

In 2021, the Canadian dollar on average strengthened relative to the U.S. dollar compared with 2020, negatively impacting our revenues. The Canadian dollar strengthened slightly relative to the U.S. dollar at December 31, 2021 compared with December 31, 2020. Combined with the realization of foreign exchange losses of $173 million on the repayment of our unsecured notes, this resulted in unrealized foreign exchange gains of $230 million on the translation of our U.S. dollar debt.

A portion of our long-term sales contracts in Asia Pacific are priced in RMB. An increase in the value of the Canadian dollar relative to the RMB will decrease the revenues received in Canadian dollars from the sale of natural gas commodities in the region. The Canadian dollar on average has remained relatively flat compared with RMB in 2021.

REPORTABLE SEGMENTS

UPSTREAM

OIL SANDS

On December 31, 2020, the Oil Sands segment included the Foster Creek, Christina Lake and Narrows Lake assets as well as other projects in the early stages of development. On January 1, 2021, as part of the Arrangement, we acquired:

- Sunrise, a SAGD oil sands project located in the Athabasca region of northern Alberta. The Cenovus operated project is a 50 percent partnership with BP Canada.
- Tucker, an oil sands project located 30 kilometres northwest of Cold Lake, Alberta.
- Lloydminster thermal projects, consisting of bitumen production from 11 thermal plants, in the Lloydminster region of Saskatchewan.
- Lloydminster conventional heavy oil, which produces heavy oil from the Lloydminster region of Alberta and Saskatchewan. This area was referred to as Lloydminster Cold/EOR in previous periods.

- A 35 percent interest in HMLP, which owns 2,200 kilometres of pipeline in the Lloydminster region and 5.9 million barrels of storage at Hardisty and Lloydminster. Financial results from HMLP are reported on an equity-accounted basis.

In 2021, we:

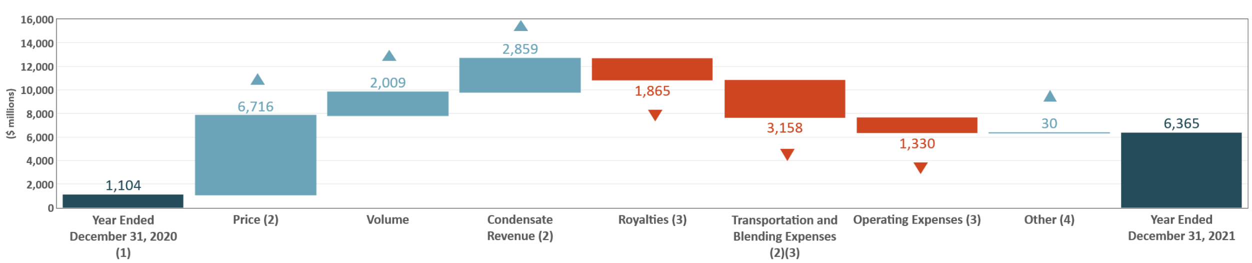
- Delivered safe and reliable operations.
- Achieved numerous single-day production records at Foster Creek, Christina Lake and our Lloydminster thermal assets.
- Produced 581.5 thousand barrels per day, compared with 381.7 thousand barrels per day in 2020.
- Increased production from 553.4 thousand barrels per day in the first quarter to 624.9 thousand barrels per day in the fourth quarter.
- Commenced tieback of the Narrows Lake field into the Christina Lake plant. First steam from Narrows Lake is expected in 2025.
- Reached an agreement to sell our Tucker asset for gross cash proceeds of $800 million. The transaction closed on January, 31, 2022.
- Earned revenues of $20.6 billion.
- Generated Operating Margin of $6.4 billion, an increase of $5.3 billion compared with 2020 primarily due to higher average realized sales prices, added volumes from assets acquired as part of the Arrangement and higher sales volumes at Foster Creek and Christina Lake.
- Invested capital of $1.0 billion primarily focused on sustaining production at Christina Lake, Foster Creek and the Lloydminster thermal assets.
- Achieved a Netback of $33.69 per BOE.

Financial Results

($ millions)	2021	2020 (1)	2019 (1)
Gross Sales (2)	**22,827**	8,804	13,101
Less: Royalties	**2,196**	331	1,143
Revenues	**20,631**	8,473	11,958
Expenses			
Purchased Product (2)	**3,188**	1,262	2,231
Transportation and Blending	**7,841**	4,683	5,152
Operating	**2,451**	1,156	1,067
Realized (Gain) Loss on Risk Management	**786**	268	23
Operating Margin	**6,365**	1,104	3,485
Unrealized (Gain) Loss on Risk Management (3)	**18**	57	92
Depreciation, Depletion and Amortization	**2,666**	1,687	1,543
Exploration Expense	**16**	9	18
Share of (Income) Loss from Equity-Accounted Affiliates	**(5)**	—	—
Segment Income (Loss)	**3,670**	(649)	1,832

(1) Prior periods have been reclassified to conform with current period's operating segments.
(2) Prior period results have been adjusted for the change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Adjustments to the Consolidated Statements of Earnings (Loss) section in this MD&A.
(3) Unrealized gain and loss on risk management is recorded in the reportable segment to which the derivative instrument relates. Comparative periods have been reclassified as these amounts were recorded in the Corporate and Eliminations segment prior to January 1, 2021.

Operating Margin Variance



(1) Prior periods have been reclassified to conform with current period's operating segments.
(2) 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.
(3) Inventory write-downs prior to January 1, 2021, have been reclassified to royalties, purchased product, transportation and blending or operating expenses to conform with the current presentation of inventory write-downs.
(4) Other includes third-party sourced volumes, construction and other activities not attributable to the production of crude oil, NGLs or natural gas.

Operating Results

	2021	2020	2019
Total Sales Volumes (MBOE/d)	**579.9**	386.6	346.7
Total Realized Price per Unit Sold [(1)] ($/BOE)	**62.82**	28.64	53.78
Crude Oil Production by Asset (Mbbls/d)			
Foster Creek	**179.9**	163.2	159.6
Christina Lake	**236.8**	218.5	194.7
Sunrise [(2)]	**25.9**	—	—
Lloydminster Thermal	**97.7**	—	—
Tucker	**21.0**	—	—
Lloydminster Conventional Heavy Oil	**20.2**	—	—
Total Daily Crude Oil Production [(3)]	**581.5**	381.7	354.3
Effective Royalty Rate (percent)	**18.7**	11.6	20.3
Per Unit Transportation and Blending Cost [(1)] ($/BOE)	**7.23**	8.70	8.94
Per Unit Operating Cost [(1)] ($/BOE)	**11.52**	7.84	8.15
Per Unit DD&A [(1)] ($/BOE)	**11.28**	10.40	11.15

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Represents Cenovus's 50 percent interest in the Sunrise operations.
(3) Oil Sands production is comprised of bitumen except for Lloydminster conventional heavy oil, which is comprised of heavy crude oil. During the year ended December 31, 2021, production comprised of medium crude oil in this area was reclassified to heavy crude oil.

Revenues

Price

Realized sales prices increased primarily due to higher WTI benchmark prices, partially offset by wider WTI-WCS differentials. In 2021, we sold approximately 20 percent (2020 – 25 percent) of our production to U.S. destinations to improve our realized sales price.

During 2021, gross sales included $2.9 billion (2020 – $1.3 billion) from third-party sourced volumes which are not included in our per-unit pricing metrics or our Netbacks. Refer to "Netback Reconciliations – Oil Sands" in this MD&A for more detail.

In 2021, gross sales included $329 million (2020 – $9 million), which are not included in our per-unit pricing metrics or our Netbacks, as it relates to transportation, blending and construction activities. Refer to "Netback Reconciliations – Oil Sands" in this MD&A for more detail.

The heavy oil and bitumen produced by Cenovus must be blended with condensate to reduce its viscosity to transport it to market through pipelines. Our realized bitumen sales price does not include the sale of condensate; however, it is influenced by the price of condensate. As the cost of condensate increases relative to the price of blended crude oil, our realized heavy oil and bitumen sales price decreases. Up to three months may lapse from when we purchase condensate to when we sell our blended production.

Cenovus makes storage and transportation decisions about our marketing and transportation infrastructure, including storage and pipeline assets, to optimize product mix, delivery points, transportation commitments and customer diversification, and to inventory physical positions. In order to price protect our inventories associated with storage or transport decisions, Cenovus employs various price alignment and volatility management strategies, including risk management contracts, to reduce volatility in future cash flows to improve cash flow stability to support financial priorities. Transactions typically span across periods and, as such, 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.

In the year ended December 31, 2021, we incurred a realized risk management loss due to the settlement of benchmark prices rising above our risk management contract prices; as physical inventory was sold we recognized an offsetting gain due to rising benchmark prices. In 2021, unrealized losses were recorded on our crude oil financial instruments primarily due to forward benchmark pricing rising above our risk management contract prices that related to future periods and the realization of settled positions.

Production Volumes

Oil Sands crude oil production was 581.5 thousand barrels per day in 2021, an increase of 199.8 thousand barrels per day compared with 2020. Production levels increased primarily due to the addition of 164.8 thousand barrels per day from assets acquired as part of the Arrangement, and increased production at Foster Creek and Christina Lake.

Production at Foster Creek increased 16.7 thousand barrels per day year-over-year due to new wells coming online in 2021, partially offset by reduced production due to a planned turnaround and operational outages in the second quarter.

Production at Christina Lake increased 18.3 thousand barrels per day year-over-year. In 2021, new wells were brought online, while in 2020 we chose to operate at reduced levels in April and completed a planned turnaround and maintenance activities in the third quarter.

Lloydminster thermal produced at high rates throughout the year as we applied our operating strategy and production and well delivery techniques. A planned turnaround was completed at Sunrise in the second quarter that impacted production. Tucker produced at stable rates.

Royalties

Royalty calculations for our Oil Sands segment are based on government prescribed royalty regimes in Alberta and Saskatchewan.

Our Alberta oil sands royalty projects (Foster Creek, Christina Lake, Sunrise and Tucker) 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 revenues of the project multiplied by the applicable royalty rate (25 percent to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales revenues less diluent costs and transportation costs. Net revenues are a function of sales revenues less diluent costs, transportation costs, and allowed operating and capital costs.

Foster Creek, Christina Lake and Tucker are post-payout projects and Sunrise is a pre-payout project.

For our Saskatchewan properties, Lloydminster thermal and Lloydminster conventional heavy oil, royalty calculations are based on an annual rate that is applied to each project, as well as each project's Crown and freehold split. For Crown royalties, the pre-payout calculation is based on a one percent rate and the post-payout calculation is based on a 20 percent rate. The freehold calculation is limited to post-payout projects and is based on an eight percent rate.

Effective royalty rates increased primarily due to higher realized pricing and higher Alberta oil sands sliding scale royalty rates, partially offset by lower rates on Saskatchewan operations acquired in the Arrangement.

Royalties increased by $1.9 billion compared with 2020, mainly due to higher net revenue as a result of higher realized pricing combined with increased production.

Expenses

Transportation and Blending

Blending costs increased by $2.9 billion in 2021 compared with 2020. At Foster Creek and Christina Lake, blending costs increased due to higher condensate prices and volumes. Blending rates at Sunrise are comparable to Foster Creek and Christina Lake. Our Tucker, Lloydminster thermal and Lloydminster conventional heavy oil assets typically have lower blending rates due to lower crude oil viscosity.

Transportation costs were $1.5 billion in 2021, an increase of $299 million compared with 2020, primarily due to volumes from assets acquired in the Arrangement. In addition, costs rose as a result of volumes transported to U.S. destinations by pipeline due to increased capacity as a result of the Arrangement, partially offset by reduced volumes shipped by rail.

Per-unit Transportation Expenses

Per-unit transportation expenses were $7.23 per BOE in 2021 (2020 – $8.70 per BOE). The decrease was mainly a result of crude oil production from Foster Creek, Christina Lake and Sunrise shipped and sold to U.S. destinations via pipeline with less reliance on rail. Also contributing to the decrease were lower per-unit transportation costs at the Tucker, Lloydminster thermal, and Lloydminster conventional heavy oil properties acquired in the Arrangement, compared with Foster Creek, Christina Lake and Sunrise.

At Foster Creek, per-unit transportation costs decreased five percent from 2020 to $10.51 per barrel as we reduced our reliance on shipping to the U.S. via rail while increasing our total volumes delivered to the U.S. via our pipeline capacity. We shipped 35 percent (2020 – 30 percent) of our volumes to U.S. destinations, of which 15 percent (2020 –30 percent) were via rail.

At Christina Lake, per-unit transportation costs decreased 11 percent from 2020 to $6.19 per barrel as less than two percent (2020 – 15 percent) of our volumes shipped to U.S. destinations were via rail.

Operating

Primary drivers of our operating expenses in 2021 were fuel, workforce, chemical costs, and repairs and maintenance. Total operating costs increased primarily due to costs on assets acquired from the Arrangement which have higher per barrel operating costs, and increased fuel costs due to higher natural gas prices, combined with the planned turnarounds at Foster Creek and Sunrise in the second quarter of 2021.

($/BOE) [1]	**2021**	**Percent Change**	2020	Percent Change	2019
Foster Creek					
Fuel	**4.07**	**44**	2.83	15	2.47
Non-Fuel	**6.67**	**4**	6.41	(4)	6.67
Total	**10.74**	**16**	9.24	1	9.14
Christina Lake					
Fuel	**3.52**	**61**	2.18	6	2.06
Non-Fuel	**4.72**	**2**	4.61	(13)	5.27
Total	**8.24**	**21**	6.79	(7)	7.33
Other Oil Sands [2]					
Fuel	**5.01**	**—**	—	—	—
Non-Fuel	**11.97**	**—**	—	—	—
Total	**16.98**	**—**	—	—	—
Total	**11.52**	**47**	7.84	(4)	8.15

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Includes Sunrise, Tucker, Lloydminster thermal and Lloydminster conventional heavy oil assets.

At both Foster Creek and Christina Lake, per barrel fuel costs increased primarily due to higher natural gas prices. Non-fuel costs were relatively flat at Foster Creek and Christina Lake as higher sales volumes offset increases due to higher electricity costs, chemical costs, the planned turnaround at Foster Creek in the second quarter of 2021, and reduced repairs and maintenance activity in 2020 due to COVID-19 safety measures.

Total unit operating costs increased $3.68 per BOE to $11.52 per BOE in 2021 compared with 2020. The increase was due to higher per-unit operating costs of the assets acquired in the Arrangement, increased Foster Creek and Christina Lake per-unit costs as discussed above, and the planned turnaround at Sunrise during the second quarter of 2021.

Netbacks

($/bbl)	**2021**	2020	2019
Sales Price [1]	**62.82**	28.64	53.78
Royalties [1]	**10.38**	2.34	8.97
Transportation [1] [2]	**7.23**	8.70	8.94
Operating Expenses [1] [2]	**11.52**	7.84	8.15
Netback [2] [3]	**33.69**	9.76	27.72

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Netbacks do not reflect non-cash write-downs of product inventory or reversals of product inventory until realized when the product is sold.
(3) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

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 2021, DD&A increased $979 million compared with 2020 primarily as a result of the Arrangement. The average depletion rate for the year ended December 31, 2021 was $11.28 per BOE (2020 – $10.40 per BOE).

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

CONVENTIONAL

On December 31, 2020, the Conventional segment included assets primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, rich in natural gas, and NGLs. The assets are in Alberta and British Columbia and include interests in numerous natural gas processing facilities.

On January 1, 2021, as part of the Arrangement, we acquired assets primarily in the same areas mentioned above and the Rainbow Lake operating area located approximately 900 kilometres northwest of Edmonton. The acquired assets include interests in several natural gas processing facilities.

In 2021, we:

- Delivered safe and reliable operations.
- In the second half of the year, closed the sale of assets in the East Clearwater and Kaybob areas of Alberta for combined gross proceeds of $103 million. Prior to closing, the assets produced a total of approximately 11.0 thousand BOE per day. On November 30, we announced the sale of primarily our Montney assets in the Wembley area for cash proceeds of approximately $238 million. The transaction is expected to close in the first quarter of 2022.
- Earned revenue of $3.1 billion.
- Generated Operating Margin of $803 million, an increase of $608 million compared with 2020, due to higher average realized sales prices and increased volumes from assets acquired as part of the Arrangement, partially offset by higher per-unit operating expenses from assets acquired as part of the Arrangement.
- Invested capital of $222 million focused on short cycle, high return development wells which are expected to improve underlying cost structures through volume enhancement and offset natural declines.
- Completed numerous turnarounds involving field maintenance activities and safely shutting-in and reactivating production.
- Achieved a Netback of $15.95 per BOE.

Financial Results

($ millions)	2021	2020 [1]	2019 [1]
Gross Sales	**3,235**	904	935
Less: Royalties	**150**	40	30
Revenues	**3,085**	864	905
Expenses			
Purchased Product	**1,655**	268	240
Transportation and Blending	**74**	81	82
Operating	**551**	320	339
Realized (Gain) Loss on Risk Management	**2**	—	—
Operating Margin	**803**	195	244
Unrealized (Gain) Loss on Risk Management [2]	**1**	—	—
Depreciation, Depletion and Amortization	**3**	880	319
Exploration Expense	**(3)**	82	64
Segment Income (Loss)	**802**	(767)	(139)

(1) Prior periods have been reclassified to conform with current period's operating segments.

(2) Unrealized gain and loss on risk management is recorded in the reportable segment to which the derivative instrument relates. Comparative periods have been reclassified as these amounts were recorded in the Corporate and Eliminations segment prior to January 1, 2021.

Revenues

In 2021, gross sales included $1.7 billion (2020 – $269 million) relating to third-party sourced volumes, which are not included in our per-unit pricing metrics or our Netbacks.

In 2021, revenues included amounts relating to processing and transportation activities for third parties of $61 million, (2020 – $49 million), which are not included in our per-unit pricing metrics or our Netbacks.

Operating Results

	2021	2020	2019
Total Sales Volumes (MBOE/d)	**133.4**	89.8	97.4
Total Realized Price per Unit Sold [(1)] ($/BOE)	**31.20**	17.84	17.95
Heavy Crude Oil ($/bbl)	—	31.45	—
Light Crude Oil ($/bbl)	**76.32**	42.78	65.70
NGLs ($/bbl)	**42.93**	22.04	26.36
Conventional Natural Gas ($/Mcf)	**4.07**	2.37	2.01
Production by Product			
Heavy Crude Oil (Mbbls/d)	—	2.7	—
Light Crude Oil (Mbbls/d)	**8.4**	4.5	4.9
NGLs (Mbbls/d)	**25.6**	19.5	21.8
Conventional Natural Gas (MMcf/d)	**597.6**	379.0	424.5
Total Daily Production (MBOE/d)	**133.6**	89.9	97.4
Conventional Natural Gas Production (percentage of total)	**75**	70	73
Crude Oil and NGLs Production (percentage of total)	**25**	30	27
Effective Royalty Rate (percent)	**10.3**	7.9	5.1
Per Unit Transportation Cost [(1)] ($/BOE)	**1.53**	2.46	2.31
Per Unit Operating Cost [(1)] ($/BOE)	**10.66**	8.99	8.79
Per Unit DD&A [(1)] ($/BOE)	**9.11**	9.85	9.15

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Revenues

Price

Our total realized sales price increased in 2021 compared with 2020 primarily due to higher crude oil and natural gas benchmark prices.

Production Volumes

Production volumes increased in 2021, primarily due to 51.2 thousand BOE per day from assets acquired as part of the Arrangement. In addition, we brought 18 new net wells on production during the year ended December 31, 2021. The production increase is partially offset by asset dispositions during the year and natural declines.

Royalties

The Conventional assets are subject to royalty regimes in Alberta and British Columbia.

Effective royalty rates for the year ended December 31, 2021, increased primarily due to higher realized pricing and lower gas cost allowance credits.

Royalties increased $110 million in 2021, compared with 2020. The increase is primarily due to higher realized prices combined with increased production resulting from assets acquired as part of the Arrangement.

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. Transportation costs decreased by $7 million in 2021 compared with 2020. Per-unit transportation costs averaged $1.53 per BOE in the year ended December 31, 2021 (2020 – $2.46 per BOE).

Operating

Primary drivers of our operating expenses in 2021 were workforce, repairs and maintenance, property tax and lease costs, and electricity. Total operating costs increased $231 million in 2021 compared with 2020 primarily due to the assets acquired in the Arrangement.

Operating costs increased $1.67 per BOE in 2021 compared with 2020 primarily due to operating expenses on assets acquired as part of the Arrangement. Per-unit operating costs in 2021, excluding assets acquired in the Arrangement, increased approximately seven percent year-over-year primarily due to volume declines, higher electricity, greenhouse gas and regulatory costs.

Netbacks

($/BOE)	2021	2020	2019
Sales Price [(1)]	**31.20**	17.84	17.95
Royalties [(1)]	**3.06**	1.23	0.83
Transportation and Blending [(1)]	**1.53**	2.46	2.31
Operating Expenses [(1)]	**10.66**	8.99	8.79
Netback [(2) (3)]	**15.95**	5.16	6.02

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Netbacks do not reflect non-cash write-downs of product inventory or reversals of product inventory until realized when the product is sold.
(3) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

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. The average depletion rate for 2021 was $9.11 per BOE (2020 – $9.85 per BOE). The average depletion rate excludes the impact of impairments and impairment reversals.

For the year ended December 31, 2021, total Conventional DD&A was $3 million (2020 – $880 million). The decrease was due to impairment write-downs of $555 million in 2020 resulting from decreases in forward commodity prices projected at the end of 2020 and impairment reversals of $378 million in 2021 due to improved forward commodity prices. The decrease was partially offset by DD&A on assets acquired in the Arrangement.

OFFSHORE

The Offshore segment was acquired as part of the Arrangement and includes offshore operations, exploration and development activities in China, the equity-accounted investment in the HCML joint venture in Indonesia and operations, exploration and development off the east coast of Canada.

In 2021, we:

- Delivered safe and reliable operations.
- Earned revenues of $1.7 billion.
- Generated Operating Margin of $1.4 billion.
- Achieved a Netback of $58.39 per BOE.
- Achieved single-day production records at our China and Indonesia assets.
- Invested capital of $175 million primarily on the West White Rose project in the Atlantic region.
- Entered into agreements with our partners to restructure our working interests on assets in the Atlantic region.

Financial Results

($ millions)	2021
Gross Sales	**1,782**
Less: Royalties	**108**
Revenues	**1,674**
Expenses	
Transportation and Blending	**15**
Operating	**239**
Operating Margin	**1,420**
Depreciation, Depletion and Amortization	**492**
Exploration Expense	**5**
Share of (Income) Loss from Equity-Accounted Affiliates	**(47)**
Segment Income (Loss)	**970**

Netbacks

	2021			
($/BOE, except where indicated)	China	Indonesia [1]	Atlantic ($/bbl)	Total Offshore
Sales Price [2]	72.44	64.52	91.01	74.75
Royalties [2]	4.25	14.93	6.07	5.96
Transportation and Blending [2]	—	—	3.02	0.54
Operating Expenses [2]	5.10	9.55	28.34	9.86
Netback [3]	63.09	40.04	53.58	58.39
Total Sales Volumes (MBOE/d)	50.8	9.5	13.2	73.5
Per Unit DD&A [2]				25.62

(1) Reported sales volumes, associated per unit values and royalty rates reflect Cenovus's 40 percent interest in the Madura-BD gas project. Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.
(2) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(3) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

DD&A

In the Offshore segment, we deplete crude oil and natural gas properties using the unit-of-production method based on estimated proved developed producing reserves or total proved plus probable reserves, together with future development costs, determined using forward prices and costs. 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 developed producing or proved plus probable reserves. The average depletion rate for the year ended December 31, 2021 was $25.62 per BOE.

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

Asia Pacific

In China, the Liwan gas project includes working interests of 49 percent in natural gas developments at the Liwan 3-1 and Liuhua 34-2 producing fields and 75 percent in the Liuhua 29-1 producing field. We also have petroleum contracts in Blocks 15/33, 16/25 and 23/07, which are in the exploration phase. We drilled an exploration well in Block 15/33 in the South China Sea in October 2021. The well encountered and tested hydrocarbons and we are evaluating the results. Block 15/33 contains an existing discovery that was drilled in 2018. We also hold exploration rights in a block located offshore Taiwan.

In Indonesia, we hold a 40 percent share in HCML, which is a joint venture that is accounted for using the equity method. HCML is engaged in the exploration for and production of crude oil and natural gas resources offshore Indonesia in the Madura Strait production sharing contract ("PSC") licence area. This area includes the producing BD field and ongoing developments at the MDA, MBH and MDK fields. The MDA and MBH fields are expected to start producing in mid-2022. A final investment decision was made in June 2021 by HCML for development of the MAC field with production expected by mid-2023. We signed a PSC in the fourth quarter of 2021 for the Liman contract area in East Java. In December 2021 we commenced the drilling of a development well in the MBH field which was completed by January 2022. We began drilling a second development well in the MBH field in the first quarter of 2022.

Financial Results

($ millions)	2021
Gross Sales	1,342
Less: Royalties	79
Revenues	1,263
Expenses	
Operating	103
Operating Margin [1]	1,160

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

Operating Results

	2021
Total Sales Volumes [(1)(2)(3)] (MBOE/d)	**60.3**
NGLs [(1)(2)(3)] (Mbbls/d)	**12.7**
Conventional Natural Gas [(1)(2)(3)] (MMcf/d)	**285.3**
Total Realized Price per Unit Sold [(3)(4)] ($/BOE)	**71.19**
NGLs [(3)] ($/bbl)	**79.83**
Conventional Natural Gas [(3)] ($/Mcf)	**11.48**
Effective Royalty Rate [(3)] (percent)	**8.4**
Per Unit Operating Expense [(3) (4)] ($/BOE)	**5.80**

(1) Sales volumes approximates total daily production.
(2) Reported sales volumes include Cenovus's working interest from the Liwan gas project.
(3) Reported sales volumes, associated per unit values and royalty rates reflect Cenovus's 40 percent interest in the Madura-BD gas project. Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.
(4) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Revenues

Price

The price we receive for natural gas in Asia is set under long-term contracts. The price we receive for NGLs is primarily driven by the price of Brent.

Production Volumes

Asia Pacific operations performed well. In 2021, daily production was relatively consistent during the year.

Royalties

Royalty rates are governed by production sharing contracts in which production is shared with the Chinese and Indonesian governments.

Expenses

Operating

Primary drivers of our operating expenses in 2021 were repairs and maintenance, insurance and workforce.

Atlantic

Our Atlantic exploration and development program is focused in the Jeanne d'Arc Basin and the Flemish Pass located offshore Newfoundland and Labrador. The Jeanne d'Arc Basin includes the Terra Nova field, as well as the White Rose field and satellite extensions, including North Amethyst, West White Rose and South White Rose. In the Flemish Pass Basin, we hold a 35 percent non-operated working interest in each of the Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen discoveries. We are the operator of the White Rose field and satellite extensions and hold an ownership interest in the Terra Nova field, as well as several smaller undeveloped fields. We also hold exploration acreage offshore Newfoundland and Labrador.

Our production in 2021 was from the White Rose field and satellite extensions.

Production operations at the Terra Nova field have been suspended since December 2019. In the third quarter, Cenovus closed agreements with its partners to restructure its working interests in the Terra Nova field. Cenovus's working interest increased to 34 percent, up from 13 percent. The Company received $78 million, before closing adjustments, from exiting partners as a contribution towards future decommissioning liabilities. The ALE project for the Terra Nova floating production, storage and offloading unit is underway in Spain for the dry dock portion of the project. Production is expected to resume before the end of 2022.

The West White Rose project remains deferred while we continue to evaluate options with our partners. In the third quarter of 2021, Cenovus entered into an agreement with Suncor to decrease our working interest in the White Rose field and satellite extensions. The working interest restructuring will not occur if the project does not proceed. Cenovus would reduce its working interest in the original field from 72.5 percent to 60.0 percent and in the satellite extensions from 68.875 percent to 56.375 percent. The decision whether to restart the West White Rose project is expected to be made by mid-2022.

Financial Results

($ millions)	2021
Gross Sales	**440**
Less: Royalties	**29**
Revenues	**411**
Expenses	
Transportation	**15**
Operating	**136**
Operating Margin (1)	**260**

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

Operating Results

	2021
Total Sales Volumes	
Light Crude Oil (Mbbls/d)	**13.2**
Total Realized Price per Unit Sold (1) ($/bbl)	
Light Crude Oil ($/bbl)	**91.01**
Total Daily Production	
Light Crude Oil (Mbbls/d)	**14.1**
Effective Royalty Rate (percent)	**6.7**
Per Unit Operating Expense (1) **($/bbl)**	**28.34**

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Revenues

Price

The price we receive for light oil is primarily driven by the price of Brent.

Production and Sales Volumes

Atlantic operations performed well. Production was relatively steady with consistently high uptime in 2021. There were minor planned outages in the third quarter and a 15-day planned maintenance on the SeaRose floating production, storage and offloading unit ("SeaRose FPSO"), starting late in the third quarter and completed in October.

Light oil from production at the White Rose field is offloaded from the SeaRose FPSO to tankers and stored at an onshore terminal before shipment to buyers. The result is a timing difference between production and sales. Our sales volumes were 13.2 thousand barrels per day in 2021.

Royalties

Royalties at the White Rose field are based on an agreement between our working interest partners and the Government of Newfoundland and Labrador. We currently pay a basic royalty of 7.5 percent of gross sales at the White Rose field and 5.0 percent of gross sales at the satellite extensions.

Expenses

Operating

Primary drivers of our operating expenses in 2021 were repairs and maintenance, workforce, vessel costs and helicopter costs.

Transportation

Transportation includes the cost of transporting crude oil from the SeaRose FPSO to onshore via tankers, as well as storage costs.

DOWNSTREAM

CANADIAN MANUFACTURING

On December 31, 2020, Canadian Manufacturing operations included the Bruderheim crude-by-rail terminal.

On January 1, 2021, as part of the Arrangement, we acquired:

- The Lloydminster Upgrader, which is designed to process blended heavy crude oil and bitumen feedstock, creating high quality, low-sulphur synthetic crude oil and ultra-low sulphur diesel. The Lloydminster Upgrader has crude oil throughput capacity of 81.5 thousand barrels per day.
- The Lloydminster Refinery, which processes heavy crude oil into asphalt products used in road construction and maintenance. The refinery also produces condensate, bulk distillates and industrial products. The Lloydminster Refinery has crude oil throughput capacity of 29.0 thousand barrels per day.
- Ethanol plants in Lloydminster, Saskatchewan and Minnedosa, Manitoba.

The Lloydminster Upgrader has the option to source crude oil feedstock from our Lloydminster thermal and Tucker production. The Lloydminster Refinery sources crude oil feedstock from our Lloydminster thermal and Lloydminster conventional heavy oil production.

In 2021 we:

- Delivered safe and reliable operations.
- Averaged combined crude utilization of 96 percent at the Lloydminster Upgrader and Lloydminster Refinery.
- Achieved multiple single-day diesel production records at the Lloydminster Upgrader.
- Generated Operating Margin of $532 million, an increase of $487 million compared with 2020 due to assets acquired in the Arrangement.
- Invested capital of $37 million.

Financial Results

($ millions)	**2021**	2020	2019
Revenues	**4,472**	82	77
Purchased Product	**3,552**	—	—
Gross Margin [(1)]	**920**	82	77
Expenses			
Operating	**388**	37	41
Operating Margin	**532**	45	36
Depreciation, Depletion and Amortization	**167**	8	7
Segment Income (Loss)	**365**	37	29

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

Operating Results

	2021	2020	2019
Crude Oil Throughput Capacity (Mbbls/d)	**110.5**	—	—
Lloydminster Upgrader (Mbbls/d)	**81.5**	—	—
Lloydminster Refinery (Mbbls/d)	**29.0**	—	—
Crude Oil Throughput (Mbbls/d)	**106.5**	—	—
Lloydminster Upgrader (Mbbls/d)	**79.0**	—	—
Lloydminster Refinery (Mbbls/d)	**27.5**	—	—
Crude Utilization (1) (percent)	**96**	—	—
Refined Products Output (Mbbls/d)	**107.9**	—	—
Upgrading Differential (2)	**16.83**	—	—
Refining Margin (3) ($/bbl)			
Lloydminster Upgrader ($/bbl)	**17.99**	—	—
Lloydminster Refinery ($/bbl)	**15.64**	—	—
Unit Operating Expense (4) ($/bbl)	**9.97**	—	—
Crude-by-Rail Operations			
Volumes Loaded (5) (Mbbls/d)	**12.1**	30.4	53.3
Ethanol Production (thousands of litres/d)	**661.0**	—	—

(1) Based on crude throughput volumes and results of operations at the Lloydminster Upgrader and Refinery.
(2) Based on benchmark price differential between heavy oil feedstock and synthetic crude.
(3) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(4) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A. Operating costs divided by crude oil throughput.
(5) Volumes transported outside of Alberta, Canada.

Revenues, Gross Margin and Refining Margin

Upgrading operations process blended heavy crude oil and bitumen into high value synthetic crude oil and low sulphur distillates. Revenues are dependent on the sales price of synthetic crude oil and diesel. Upgrading gross margin is primarily dependent on the differential between the sales price of synthetic crude oil and diesel, and the cost of heavy crude oil feedstock.

Lloydminster Refinery operations process blended heavy crude oil into asphalt and industrial products. Revenues are dependent on market prices for asphalt and other industrial products. The gross margin is primarily dependent on revenues and the cost of heavy crude oil feedstock. Sales from the Lloydminster Refinery increase during paving season, which typically runs from May through October each year.

For the year ended December 31, 2021, revenue includes approximately $55 million for a customer settlement of a take-or-pay contract related to Bruderheim crude-by-rail terminal operations. Revenues and gross margin decreased compared with 2020 due to minimal third-party volumes loaded and Cenovus's reduced reliance on rail.

Operating Expense

Primary drivers of operating expenses in 2021, were workforce, repairs and maintenance, and energy costs. For the year ended December 31, 2021, unit operating expenses were $9.97 per barrel of crude throughput.

DD&A

Canadian Manufacturing 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. For the year ended December 31, 2021, Canadian Manufacturing DD&A was $167 million (2020 – $8 million) as a result of DD&A on assets acquired as part of the Arrangement.

U.S. MANUFACTURING

On December 31, 2020, U.S. Manufacturing operations included our 50 percent interest in WRB Refining LP, which owns the Wood River and Borger refineries. WRB Refining LP is jointly owned with operator Phillips 66.

On January 1, 2021, as part of the Arrangement, we acquired:

- The Lima Refinery, which we wholly own, is located in Lima, Ohio. The refinery produces low sulphur gasoline, gasoline blend stocks, ultra-low sulphur diesel, jet fuel, petrochemical feedstock and other by-products.
- The Toledo Refinery, with a 50 percent ownership interest and operated by BP Products North America Inc. ("BP"), through BP-Husky Refining LLC. Products from the refinery include low sulphur gasoline, ultra-low sulphur diesel, jet fuel and other by-products.
- The Superior Refinery, which we wholly own, is located in Superior, Wisconsin. On April 26, 2018, the refinery experienced an incident while preparing for a major turnaround and was taken out of operation. The refinery is being rebuilt and is expected to restart around the first quarter of 2023.

In 2021:

- At the Wood River and Borger refineries, throughput was negatively impacted by:
  - Planned turnarounds commenced in the first quarter and completed in the second quarter.
  - Temporary unplanned outages during the year.
- At the Lima Refinery, throughput was negatively impacted by:
  - A planned turnaround completed in October and November and subsequent unplanned equipment outages. The refinery returned to normal operations towards the end of January 2022.
  - Temporary unplanned outages in the first quarter.
  - A two-week disruption in the first quarter at the Mid-Valley pipeline, which transports feedstock to the Lima Refinery.
  - Third-party maintenance on feeder pipelines in the second quarter.
- At the Toledo Refinery, throughput was optimized in line with market demand.
- Increased crude utilization to 80 percent from 75 percent in 2020 as we ramped up throughput early in the first quarter as market crack spreads improved, partially offset by the factors discussed above.
- We invested capital of $995 million focused primarily on the Superior Refinery rebuild, combined with refining reliability, maintenance and yield optimization projects at the Wood River and Borger refineries, and maintenance projects at the Toledo Refinery.

Financial Results

($ millions)	**2021**	2020 [1]	2019 [1]
Revenues	**20,043**	4,733	8,291
Purchased Product	**17,955**	4,429	6,735
Gross Margin [2]	**2,088**	304	1,556
Expenses			
Operating	**1,772**	748	877
Realized (Gain) Loss on Risk Management	**104**	(21)	(16)
Operating Margin	**212**	(423)	695
Unrealized (Gain) Loss on Risk Management [3]	**1**	(1)	1
Depreciation, Depletion and Amortization	**2,381**	728	273
Segment Income (Loss)	**(2,170)**	(1,150)	421

(1) Prior periods have been reclassified to conform with current period's operating segments.
(2) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(3) Unrealized gain and loss on risk management is recorded in the reportable segment to which the derivative instrument relates. Comparative periods have been reclassified as these amounts were recorded in the Corporate and Eliminations segment prior to January 1, 2021.

Select Operating Results

	2021	2020	2019
Crude Oil Throughput Capacity (Mbbls/d)	**502.5**	247.5	241.0
Lima Refinery	**175.0**	—	—
Toledo Refinery (1)	**80.0**	—	—
Wood River and Borger Refineries (1)	**247.5**	247.5	241.0
Crude Oil Throughput (Mbbls/d)	**401.5**	185.9	221.3
Lima Refinery	**126.9**	—	—
Toledo Refinery (1)	**69.9**	—	—
Wood River and Borger Refineries (1)	**204.7**	185.9	221.3
Throughput by Product (Mbbls/d)			
Heavy Crude Oil	**138.7**	74.6	88.3
Light and Medium Crude Oil	**262.8**	111.3	133.0
Crude Utilization (percent)	**80**	75	92
Refining Margin (2)(3) ($/bbl)	**14.25**	4.47	19.26
Unit Operating Expense (3)(4) ($/bbl)	**12.09**	11.00	10.86

(1) Represents Cenovus's 50 percent interest in Wood River, Borger and Toledo refinery operations.
(2) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(3) Based on crude oil throughput volumes and operating results at Wood River, Borger, Lima and Toledo refineries.
(4) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

All refineries continue to optimize throughput as market conditions dictate. We began economic crude rate reductions late in the first quarter of 2020 in response to reduced demand for refined products resulting from COVID-19. Our refineries continued to run at reduced rates until early in the first quarter of 2021 as market crack spreads started to improve. Throughput was impacted in the second and third quarters due to planned and unplanned outages, and in the fourth quarter due to the planned turnaround at the Lima Refinery.

At the Lima Refinery, we had a temporary unplanned outage in the first quarter of 2021 due to an incident that shut down our fluid catalytic cracking unit. In addition, for two weeks in February, winter storm Uri disrupted the Mid-Valley pipeline that supplies the refinery's feedstock, further impacting throughput. Throughput rates began ramping up in March as market conditions improved. In the second quarter, there was third-party maintenance on the Mid-Valley and West Texas Gulf pipelines, which reduced throughput. Throughput rates increased in late May and June after completion of the maintenance. Production slowed at the end of September as we prepared for a planned turnaround completed in October and November. We encountered unplanned equipment outages subsequent to the completion of the turnaround. As a result, crude utilization at the refinery in the fourth quarter was only 34 percent, compared with 85 percent in the first nine months of 2021.

At the Toledo Refinery, throughput was optimized in line with market demand in 2021.

At the Wood River and Borger refineries, planned turnarounds began in the first quarter and were completed by mid-May and early April, respectively. Throughput was further impacted, temporarily, by unplanned outages in 2021. In the fourth quarter, crude utilization at the refineries was 92 percent.

Revenues and 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. Processing less expensive crude relative to WTI creates a feedstock cost advantage. Our feedstock costs are valued on a FIFO accounting basis.

In 2021, revenues increased $15.3 billion due to volumes from assets acquired in the Arrangement and higher refined product pricing benchmarks.

In 2021, gross margin increased $1.8 billion compared with 2020 driven by improved market crack spreads combined with increased throughput from the Arrangement and the Wood River and Borger refineries, partially offset by higher RINs costs.

In 2021, the RINs costs were $880 million (2020 – $177 million) due to higher RINs pricing and assets acquired in the Arrangement. RINs prices were US$6.76 per barrel in the year ended December 31, 2021 (2020 – US$2.48 per barrel). RINs pricing was volatile during the year, ranging from below US$4.00 per barrel to almost US$10.00 per barrel.

Operating Expenses

Primary drivers of operating expenses for the year ended December 31, 2021, were workforce costs, repairs, maintenance, services and energy costs. In 2021, operating costs increased $1.0 billion year-over-year. The increase was due to:

- Operating expenses on assets acquired in the Arrangement.
- Turnaround activities at the Wood River, Borger and Lima refineries.
- Higher utility pricing at the Lima and Borger refineries associated with the impacts of winter storm Uri in the first quarter of 2021.

DD&A

U.S. Manufacturing 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. U.S. Manufacturing DD&A was $2.4 billion in 2021 (2020 – $728 million). The increase is the result of DD&A on assets acquired in the Arrangement, and impairment charges of $1.9 billion in the Lima, Wood River and Borger cash-generating units ("CGU"). The increase is partially offset by an impairment charge of $450 million related to the Borger CGU in 2020.

RETAIL

Retail operations were acquired on January 1, 2021, as part of the Arrangement.

As of December 31, 2021, there were 531 independently operated Husky and Esso-branded petroleum product outlets. Our retail and commercial operating model is balanced by corporate owned/dealer operated and branded dealer-owned-and-operated sites. The network consists of a variety of full- and self-serve retail stations, travel centres and cardlocks serving urban and rural markets across Canada, while our bulk distributors offer direct sales to commercial and agricultural markets in the prairie provinces.

On November 30, 2021, Cenovus announced agreements to sell 337 gas stations within our retail fuels network for total cash proceeds of $420 million before closing adjustments. The sales are expected to close in mid-2022. We are retaining our commercial fuels business, which includes 167 cardlock, bulkplant and travel centre locations.

Financial Results

($ millions)	2021
Gross Sales	2,158
Purchased Product	2,019
Gross Margin [(1)]	139
Expenses	
Operating	98
Operating Margin	41
Depreciation, Depletion and Amortization	59
Segment Income (Loss)	(18)

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

Select Operating Results

	2021
Fuel Sales Volume, including wholesale	
Fuel Sales (millions of litres/d)	6.9
Fuel Sales per Retail Outlet (thousands of litres/d)	13.0

Gross Margin

Gross margin is primarily driven by gasoline and diesel prices and retail pricing for motor fuels.

Operating expenses

Primary drivers of our operating expenses for the year ended December 31, 2021, were repairs and maintenance, property tax, workforce and utilities.

DD&A

Retail assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 30 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. For the year ended December 31, 2021, Retail DD&A was $59 million as a result of retail assets acquired in the Arrangement.

CORPORATE AND ELIMINATIONS

For the year ended December 31, 2021, our Corporate and Eliminations risk management activities resulted in realized risk management losses of $101 million (2020 – losses of $5 million) primarily due to the realization, in the first quarter of 2021, of WTI put and call option contracts acquired as part of the Arrangement.

Expenses

($ millions)	**2021**	2020	2019
General and Administrative	**849**	292	331
Finance Costs	**1,082**	536	511
Interest Income	**(23)**	(9)	(12)
Integration Costs	**349**	29	—
Foreign Exchange (Gain) Loss, Net	**(174)**	(181)	(404)
Re-measurement of Contingent Payment	**575**	(80)	164
(Gain) Loss on Divestiture of Assets	**(229)**	(81)	(2)
Other (Income) Loss, Net	**(309)**	40	9
	2,120	546	597

General and Administrative

Primary drivers of our general and administrative expenses were workforce costs, employee long-term incentive costs, information technology costs and operating costs associated with our real estate portfolio. For the year ended December 31, 2021, general and administrative expenses increased compared with 2020 due to a larger workforce resulting from the Arrangement and a provision for incentive rewards related to reaching our synergy targets. In addition, in 2021 long-term incentive costs were higher than 2020 due to share price increases.

Finance Costs

In the year ended December 31, 2021, finance costs increased by $546 million due to:

- Interest expense on long-term debt assumed as part of the Arrangement.
- A $121 million net premium on the redemption of long-term debt in the third and fourth quarters of 2021.
- Increased unwinding of the discount on decommissioning liabilities as a result of the Arrangement.
- Interest expense on lease liabilities as result of liabilities assumed as part of the Arrangement.

The weighted average interest rate on outstanding debt for the year ended December 31, 2021, was 4.6 percent (2020 – 4.9 percent).

Integration Costs

For the year ended December 31, 2021, we incurred $349 million of costs as a result of the Arrangement, not including capital expenditures. Integration costs included $180 million of severance payments, $65 million of transaction costs and $104 million in other integration related costs in 2021.

Foreign Exchange

($ millions)	**2021**	2020	2019
Unrealized Foreign Exchange (Gain) Loss	**(312)**	(131)	(827)
Realized Foreign Exchange (Gain) Loss	**138**	(50)	423
	(174)	(181)	(404)

In 2021, unrealized foreign exchange gains of $312 million were mainly as a result of the translation of our U.S. dollar denominated debt. Realized foreign exchange losses of $138 million were recorded primarily due to the recognition of a $173 million loss on the repurchase of U.S. dollar denominated debt in the third and fourth quarters of 2021.

Re-measurement of Contingent Payment

Related to Foster Creek and Christina Lake production, Cenovus 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 its 50 percent interest in the FCCL Partnership on May 17, 2017, 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 agreement expires on May 17, 2022.

The contingent payment is accounted for as a financial option. The fair value of $236 million as at December 31, 2021, 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, 2021, non-cash re-measurement losses of $575 million were recorded. As at December 31, 2021, $160 million is payable under this agreement. In 2021, we paid $242 million under this agreement, of which $175 million was recognized as cash flow from operating activities and reduced Adjusted Funds Flow. All future payments will be recognized as a reduction to cash flow from operating activities and Adjusted Funds Flow.

Average WCS forward pricing for the remaining term of the contingent payment is $77.87 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately $77.35 per barrel and $78.39 per barrel.

Other (Income) Loss, Net

For the year ended December 31, 2021, other (income) loss increased by $349 million. The increase is primarily due to:

- Business interruption insurance proceeds related to the Superior Refinery of $120 million in 2021.
- A $100 million loss related to the Keystone XL pipeline project in 2020.
- The settlement of a legal claim in favour of Cenovus in 2021.
- Other income of $35 million in 2021 related to the Headwater warrants, which were exercised in December 2021.

DD&A

Corporate and Eliminations DD&A is 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. ROU assets are depreciated on a straight-line basis over the estimated useful life of the asset or the lease term. DD&A for the year ended December 31, 2021, was $118 million (2020 – $161 million). The decrease in DD&A year-over-year was primarily due to $52 million of information technology assets that were written off in 2020 in anticipation of the Arrangement closing.

Income Tax

($ millions)	**2021**	2020	2019
Current Tax			
Canada	**104**	(14)	14
United States	**—**	1	3
Asia Pacific	**171**	—	—
Other International	**1**	—	—
Current Tax Expense (Recovery)	**276**	(13)	17
Deferred Tax Expense (Recovery)	**452**	(838)	(814)
Total Tax Expense (Recovery)	**728**	(851)	(797)

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

($ millions, except tax rates)	2021	2020	2019
Earnings (Loss) From Operations Before Income Tax	**1,315**	(3,230)	1,397
Canadian Statutory Rate	**23.7 %**	24.0 %	26.5 %
Expected Income Tax Expense (Recovery) From Operations	**312**	(775)	370
Effect on Taxes Resulting From:			
Statutory and Other Rate Differences	**3**	19	(52)
Non-Taxable Capital (Gains) Losses	**63**	(42)	(38)
Non-Recognition of Capital (Gains) Losses	**27**	(42)	(39)
Adjustments Arising From Prior Year Tax Filings	**(5)**	(8)	4
Recognition of U.S. Tax Basis	**—**	—	(387)
U.S. Tax Attribute Limitation	**217**	—	—
Impact of Rate Changes	**106**	(7)	(671)
Other	**5**	4	16
Total Tax Expense (Recovery) From Operations	**728**	(851)	(797)
Effective Tax Rate	**55.4 %**	26.3 %	(57.1)%

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, 2021, the Company recorded a current tax expense primarily related to taxable income arising in Canada and Asia Pacific. The increase is due to Asia Pacific operations acquired in the Arrangement and higher earnings compared with 2020. In the fourth quarter we recorded a $217 million deferred tax expense due to a limitation in the availability of certain U.S. tax attributes. In addition, the Company recorded a deferred tax expense of $106 million due to a rate change associated with provincial allocations.

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.

QUARTERLY RESULTS

($ millions, except where indicated)	2021 Q4	2021 Q3	2021 Q2	2021 Q1	2020 Q4	2020 Q3	2020 Q2	2020 Q1
Average Commodity Prices (US$/bbl)								
Brent [(1)]	**79.73**	73.47	68.83	60.90	44.22	42.99	29.20	50.26
WTI	**77.19**	70.56	66.07	57.84	42.66	40.93	27.85	46.17
WCS	**62.55**	56.98	54.58	45.37	33.36	31.84	16.38	25.64
Chicago 3-2-1 Crack Spread	**16.06**	20.67	20.50	12.93	7.05	7.89	6.44	8.79
RINs	**6.11**	7.32	8.12	5.49	3.48	2.64	2.21	1.58
Production Volumes (MBOE/d)	**825.3**	804.8	765.9	769.3	467.2	471.8	465.4	482.6
Bitumen (Mbbls/d)	**606.0**	576.5	528.6	532.9	380.7	386.0	373.2	387.0
Heavy Crude Oil (Mbbls/d) [(2)]	**18.9**	20.5	20.8	20.5	1.9	3.2	2.2	3.6
Light and Medium Crude Oil (Mbbls/d) [(2)]	**17.8**	22.6	24.4	25.6	4.3	4.3	4.3	5.1
NGLs (Mbbls/d)	**35.6**	35.5	41.1	41.1	18.4	18.3	20.3	21.1
Conventional Natural Gas (MMcf/d)	**883.5**	897.9	905.6	894.9	369.5	360.1	392.2	394.8
Crude Throughput [(3)] (Mbbls/d)	**469.9**	554.1	539.0	469.1	169.0	191.1	162.3	221.1
Revenues [(4)]	**13,726**	12,701	10,637	9,293	3,543	3,737	2,311	3,952
Operating Margin	**2,600**	2,710	2,184	1,879	625	594	291	(589)
Cash From (Used in) Operating Activities	**2,184**	2,138	1,369	228	250	732	(834)	125
Adjusted Funds Flow [(5)]	**1,948**	2,342	1,817	1,141	333	407	(469)	(154)
Capital Investment	**835**	647	534	547	242	148	147	304
Free Funds Flow	**1,113**	1,695	1,283	594	91	259	(616)	(458)
Net Earnings (Loss)	**(408)**	551	224	220	(153)	(194)	(235)	(1,797)
Per Share - basic ($)	**(0.21)**	0.27	0.11	0.10	(0.12)	(0.16)	(0.19)	(1.46)
Per Share - diluted ($)	**(0.21)**	0.27	0.11	0.10	(0.12)	(0.16)	(0.19)	(1.46)
Long-Term Debt, Including Current Portion [(6)]	**12,385**	12,986	13,380	13,947	7,441	7,797	8,085	6,979
Net Debt [(7)]	**9,591**	11,024	12,390	13,340	7,184	7,530	8,232	7,421
Cash Dividends								
Common Shares	**70**	35	36	35	—	—	—	77
Per Common Share ($)	**0.0350**	0.0175	0.0175	0.0175	—	—	—	0.0625
Preferred Shares	**8**	9	8	9	—	—	—	—

(1) Calendar month average of settled prices for Dated Brent.
(2) Medium crude oil production in the first three quarters of 2021 was reclassified to heavy oil production.
(3) Represents Cenovus's net interest in refining operations. The comparative periods have been restated to Cenovus's net interest.
(4) Comparative figures have been re-presented for portion of inventory write-downs reclassified to royalties. Prior period results have been adjusted for the change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Adjustments to the Consolidated Statements of Earnings (Loss) section in this MD&A.
(5) Comparative figures have been restated to conform with the definition in this MD&A.
(6) Includes current portion of long-term debt of $nil as at December 31, 2021, $545 million as at September 30, 2021 and $632 million as at June 30, 2021 (March 31, 2021, December 31, 2020, September 30, 2020, June 30, 2020 and March 31, 2020 – $nil).
(7) In 2021, includes long-term debt, including current portion, and short-term borrowings assumed at fair value of $6.6 billion as part of the Arrangement, net of cash and cash equivalents assumed of $735 million.

Fourth Quarter 2021 Results Compared with the Fourth Quarter 2020

The summary below compares financial results for the three months ended December 31, 2021 compared with 2020. Variances from the prior year reflect higher commodity prices, the impact of assets acquired in the Arrangement and strong performance from our upstream assets.

Upstream Production Volumes

Production increased 358.1 thousand BOE per day compared with the fourth quarter of 2020, primarily due to 285.4 thousand BOE per day from assets acquired in the Arrangement and higher production at Foster Creek and Christina Lake. The increases at Foster Creek and Christina Lake were due to new wells coming online in 2021 in contrast with a planned turnaround at Christina Lake and operational outages at Foster Creek in the fourth quarter of 2020.

In the fourth quarter of 2021, we sold approximately 20 percent (2020 – 20 percent) of our Oil Sands production to U.S. destinations to improve our realized sales prices.

Conventional production increased by 39.1 thousand BOE per day compared with the fourth quarter of 2020 primarily due to assets acquired in the Arrangement, partially offset by the disposition of assets in the East Clearwater and Kaybob areas in 2021.

Offshore production was 73.1 thousand BOE per day during the quarter and is entirely from assets acquired in the Arrangement.

Downstream Manufacturing

In the Canadian Manufacturing segment, the Lloydminster Upgrader and Lloydminster Refinery ran at or near capacity throughout the fourth quarter of 2021.

U.S. Manufacturing throughput increased 192.6 thousand barrels per day compared with the fourth quarter of 2020 due to 134.3 thousand barrels per day of throughput from assets acquired in the Arrangement and significantly higher throughput at the Wood River and Borger refineries as the market for refined products improved. We completed a planned turnaround at the Lima Refinery in October and November and subsequently encountered unplanned equipment outages. At the Toledo Refinery, throughput was optimized in line with market demand throughout 2021. In the fourth quarter of 2021, the Toledo Refinery achieved a crude utilization rate of 94 percent.

Revenues

Total revenues increased $10.2 billion in the fourth quarter of 2021 compared with the same period of 2020. Downstream revenues increased $7.0 billion primarily due to higher refined product pricing consistent with the improved average refined product benchmark prices and higher refined product output due to increased throughput. Upstream revenues increased by $5.5 billion primarily due to higher realized sales prices of $70.02 per BOE compared with $38.37 per BOE in 2020, combined with increased sales volumes.

Operating Margin

Operating Margin increased in the fourth quarter of 2021, primarily due to:

- Higher average crude oil, NGLs and natural gas sales prices resulting from higher benchmark pricing.
- Upstream and refined products sales volumes from assets acquired in the Arrangement.
- Increased sales at Foster Creek and Christina Lake.
- Higher market crack spreads in the U.S. Manufacturing segment.

These increases in Operating Margin were partially offset by:

- Increased blending costs due to higher condensate prices and volumes.
- Higher royalties, transportation and blending costs, and operating expenses from assets acquired in the Arrangement.
- Higher realized risk management losses due to the settlement of benchmark prices relative to our risk management contract prices.
- Increased RINs costs impacting our U.S. Manufacturing segment.

Cash From (Used in) Operating Activities and Adjusted Funds Flow

Cash From Operating Activities and Adjusted Funds Flow were significantly higher in 2021 due to increased Operating Margin, as discussed above, and a $100 million loss on the Keystone XL pipeline project in the fourth quarter of 2020. The increase was partially offset by:

- Higher finance costs due to interest expense on long-term debt assumed as part of the Arrangement.
- Increased general and administrative expenses due to a larger workforce resulting from the Arrangement and provisions related to reaching our synergy-focused incentive plan.
- Contingent payment of $119 million. In the fourth quarter of 2020, the contingent payment was recorded to cash from (used in) investing activities.

The change in non-cash working capital in the fourth quarter of 2021 was primarily due to an increase in accounts payable and decrease in accounts receivable, partially offset by increase in inventories on December 31, 2021, compared with September 30, 2021. In the three months ended December 31, 2021, accounts receivable decreased primarily due to the timing of cash receipts from customers, wider heavy oil differentials to close the quarter compared to the third quarter and lower sales volumes in the U.S. Manufacturing segment. The decreases were partially offset by higher sales volumes in the Oil Sands segment to close the quarter. The increase in inventory was primarily due to a build of crude oil volumes held in inventory at Foster Creek and Christina Lake. The increase in accounts payable relates to higher accrued long-term incentives, higher accrued condensate purchases, higher accrued contingent liability payable and higher income taxes payable.

Net Earnings (Loss)

Net Loss in the fourth quarter of 2021 was higher than the Net Loss in 2020 due to:

- Impairment charges of $1.9 billion in the U.S. Manufacturing segment in 2021.
- Lower unrealized foreign exchange gains compared with 2020.
- Provisions related to reaching our synergy-focused incentive plan.
- Increased general and administrative costs, finance expenses and DD&A expense as a result of the Arrangement.
- Income tax expense compared with a recovery in 2020.

The increase was partially offset by:

- Higher Operating Margin, as discussed above.
- Impairment reversals of $378 million in the Conventional segment in the fourth quarter of 2021.
- Impairment charges of $240 million in the Conventional segment in the fourth quarter of 2020.
- Unrealized risk management gain of $222 million (2020 – $49 million loss).
- Higher other income due to business interruption insurance proceeds related to the Superior Refinery in 2021 and a $100 million loss on the Keystone XL pipeline project in the fourth quarter of 2020.

Capital Investment

Capital investment in the fourth quarter of 2021 was $835 million, compared with $242 million in the fourth quarter of 2020. The increase is primarily due to the reduction of our capital investment program in 2020 in response to COVID-19 and capital investment on assets acquired in the Arrangement.

OIL AND GAS RESERVES

As at December 31, 2021 (before royalties) [1]	Bitumen [2] (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas [3] (Bcf)	Total (MMBOE)
Total Proved	5,573	45	89	2,219	**6,077**
Probable	1,850	152	39	959	**2,201**
Total Proved Plus Probable	7,423	197	128	3,178	**8,278**

As at December 31, 2020 (before royalties)	Bitumen (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas [3] (Bcf)	Total (MMBOE)
Total Proved	4,812	7	50	965	**5,030**
Probable	1,520	6	31	601	**1,656**
Total Proved Plus Probable	6,332	13	81	1,566	**6,686**

(1) Includes reserves associated with the Tucker asset sold on January 31, 2022, representing before royalties reserves of 123 million barrels and 145 million barrels on a total proved and total proved plus probable basis, respectively.
(2) Includes heavy crude oil reserves that are not material.
(3) Includes shale gas reserves that are not material.

Developments in 2021 compared with 2020 include:

- Bitumen total proved and total proved plus probable reserves increased by 761 million barrels and 1.1 billion barrels, respectively, due to additions from the Arrangement, improved performance at Christina Lake and a regulatory approval at our Lloydminster thermal assets, partially offset by current year production.
- Light and medium oil total proved and total proved plus probable reserves increased by 38 million barrels and 184 million barrels, respectively, due to additions from the Arrangement, updates to the Conventional segment development plan, the Terra Nova restructuring, and economic factors due to increased product pricing. The increases were partially offset by dispositions in the Conventional segment and current year production.
- NGLs total proved and total proved plus probable reserves increased by 39 million barrels and 47 million barrels, respectively, due to additions from the Arrangement, updates to the Conventional segment development plan, and economic factors due to increased product pricing. The increases were partially offset by dispositions in the Conventional segment and current year production.
- Conventional natural gas total proved and total proved plus probable reserves increased by 1.3 trillion cubic feet and 1.6 trillion cubic feet, respectively, due to additions from the Arrangement, updates to the Conventional segment development plan, the sanctioning of the MAC field in Indonesia, and economic factors due to improved product pricing. The increases were partially offset by dispositions in the Conventional segment and current year production.

The reserves data is presented as at December 31, 2021 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, 2022. Comparative information as at December 31, 2020 uses the January 1, 2021 IQRE Average Forecast prices and costs.

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*" is contained in our AIF for the year ended December 31, 2021. 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.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2021	2020	2019
Cash From (Used In)			
Operating Activities	**5,919**	273	3,285
Investing Activities	**(942)**	(863)	(1,432)
Net Cash Provided (Used) Before Financing Activities	**4,977**	(590)	1,853
Financing Activities	**(2,507)**	837	(2,413)
Foreign Currency	**25**	(55)	(35)
Increase (Decrease) in Cash and Cash Equivalents	**2,495**	192	(595)

As at December 31, ($ millions)	2021	2020	2019
Cash and Cash Equivalents (1)	**2,873**	378	186
Total Debt (2)	**12,464**	7,562	6,699

(1) *On January 1, 2021, we acquired cash and cash equivalents of $735 million on the closing of the Arrangement.*
(2) *On January 1, 2021, on the closing of the Arrangement, we acquired Total Debt with a fair value of $6.6 billion.*

Cash From (Used in) Operating Activities

For the year ended December 31, 2021, cash generated from operating activities increased mainly due to higher Operating Margin combined with distributions received from equity-accounted affiliates. The increase was partially offset by changes in non-cash working capital, and higher finance costs, general and administrative costs, and integration costs as discussed in the Corporate and Eliminations section of this MD&A.

Excluding the current portion of the contingent payment and assets and liabilities held for sale, our adjusted working capital was $3.8 billion at December 31, 2021, compared with $653 million at December 31, 2020. The increase was primarily due to working capital acquired from the Arrangement and the improved commodity price environment as discussed in the Operating and Financial Results section of this MD&A. Working capital increased due to increased accounts receivable and inventories, partially offset by increased accounts payable.

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 the year ended December 31, 2021 compared with 2020 primarily due to cash acquired through the Arrangement, proceeds from divestitures and changes in non-cash working capital. These cash inflows are partially offset by higher capital spending mainly as result of our larger asset base acquired through the Arrangement.

Cash From (Used in) Financing Activities

During the year ended December 31, 2021, we closed a public offering in the U.S. for US$1.25 billion of senior unsecured notes, consisting of US$500 million 2.65 percent senior unsecured notes due January 15, 2032 and US$750 million 3.75 percent senior unsecured notes due February 15, 2052. We also paid US$2.3 billion to repurchase a portion of our unsecured notes with a principal amount of US$2.2 billion. In addition, we repaid $77 million in short-term borrowings and $350 million of revolving long-term debt.

For the year ended December 31, 2021, the Company purchased 17 million common shares through the NCIB which allows the Company to purchase up to 146.5 million common shares between November 9, 2021 and November 8, 2022. The shares were purchased at an average price of $15.56 per common share for a total of $265 million. The common shares were subsequently cancelled.

Long-Term Debt and Total Debt

Total Debt as at December 31, 2021 was $12.5 billion (December 31, 2020 – $7.6 billion), which includes $12.4 billion of long-term debt. The increase in Total Debt was primarily due to the assumption of Total Debt with a fair value of $6.6 billion at closing of the Arrangement. The principal amount of debt assumed from Husky that is owed to lenders between 2024 and 2037 is $4.5 billion. We have reduced our Total Debt by $1.7 billion since the closing of the Arrangement as described in the cash used in financing activities above.

Subsequent to year-end, we announced we are repurchasing US$384 million in principal of outstanding notes due in 2023 and 2024 on February 9, 2022.

As at December 31, 2021, we were in compliance with all of the terms of our debt agreements.

Available Sources of Liquidity

The following sources of liquidity are available as at December 31, 2021:

($ millions)	Term	Amount Available
Cash and Cash Equivalents	**Not applicable**	**2,873**
Committed Credit Facilities		
Revolving Credit Facility – Tranche A	**August 2025**	**4,000**
Revolving Credit Facility – Tranche B	**August 2024**	**2,000**
Uncommitted Demand Facilities		
Cenovus Energy Inc.	**Not applicable**	**1,015**
WRB Refining LP (Cenovus’s proportionate share)	**Not applicable**	**111**
Sunrise Oil Sands Partnership (Cenovus’s proportionate share)	**Not applicable**	**5**

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. During 2021, we were upgraded by Fitch Ratings to investment grade. We remain committed to maintaining our investment grade credit ratings at S&P Global Ratings, Moody’s Investor Service, DBRS Limited and Fitch Ratings. The cost and availability of borrowing and access to sources of liquidity and capital is dependent on current credit ratings and market conditions.

Under the terms of our committed credit facility, we are required to maintain a debt to capitalization ratio, as defined in the debt agreements, not to exceed 65 percent. We are well below this limit.

Committed Credit Facilities

As at December 31, 2021, Cenovus had a total committed credit facility of $6.0 billion that consists of a $2.0 billion tranche maturing on August 18, 2024 and a $4.0 billion tranche maturing on August 18, 2025. As at December 31, 2021, no amount was drawn on the committed credit facility (December 31, 2020 – $nil).

Uncommitted Demand Facilities

In the fourth quarter, we cancelled and replaced all uncommitted demand facilities with new uncommitted demand facilities. We have uncommitted demand facilities of $1.9 billion in place, of which $1.4 billion may be drawn for general purposes or the full amount can be available to issue letters of credit. As at December 31, 2021, there were no direct borrowings drawn on these facilities (December 31, 2020 – $nil) and there were outstanding letters of credit aggregating to $565 million (December 31, 2020 – $441 million).

WRB Refining LP has uncommitted demand facilities of US$300 million (our proportionate share – US$150 million) available to cover short-term working capital requirements. As at December 31, 2021, US$125 million was drawn on these facilities, of which US$63 million ($79 million) was our proportionate share (December 31, 2020 – $121 million). Subsequent to December 31, 2021, WRB added an incremental US$150 million demand facility (our proportionate share - US$75 million).

Sunrise Oil Sands Partnership has an uncommitted demand credit facility of $10 million available for general purposes. Our proportionate share is $5 million. There were no amounts drawn on this demand credit facility on December 31, 2021 (December 31, 2020 – $nil).

Canadian Dollar Unsecured Notes and U.S. Dollar Denominated Unsecured Notes

At December 31, 2021, the total outstanding principal amount of U.S. dollar denominated unsecured notes was US$7.4 billion and the total outstanding principal amount of Canadian dollar denominated unsecured notes was $2.8 billion.

Effective March 31, 2021, Cenovus Energy Inc., as a result of the Arrangement and subsequent amalgamation of Husky Energy Inc. into Cenovus Energy Inc., became the direct obligor under the existing US$500 million 3.95 percent notes due 2022, US$750 million 4.00 percent notes due 2024, $750 million 3.55 percent notes due 2025, $750 million 3.60 percent notes due 2027, $1.25 billion 3.50 percent notes due 2028, US$750 million 4.40 percent notes due 2029, US$387 million 6.80 percent notes due 2037 and other direct obligations of Husky Energy Inc.

The Company closed a public offering in the U.S. on September 13, 2021 for US$1.25 billion of senior unsecured notes, consisting of US$500 million 2.65 percent senior unsecured notes due January 15, 2032 and US$750 million 3.75 percent senior unsecured notes due February 15, 2052.

As noted earlier, in September and October 2021, the Company paid US$2.3 billion to repurchase a portion of its unsecured notes with a principal amount of US$2.2 billion. A net premium on redemption of $121 million was recorded in finance costs. The following principal amounts of Cenovus's unsecured notes were repurchased:

- 3.95 percent unsecured notes due 2022 – US$500 million (fully repurchased).
- 3.00 percent unsecured notes due 2022 – US$500 million (fully repurchased).
- 3.80 percent unsecured notes due 2023 – US$335 million.
- 4.00 percent unsecured notes due 2024 – US$481 million.
- 5.38 percent unsecured notes due 2025 – US$334 million.

Subsequent to year-end, we announced our intent to repurchase the remaining principal of US$384 million of the outstanding notes due in 2023 and 2024 on February 9, 2022.

Base Shelf Prospectus

We have 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 November 2023. As at December 31, 2021, US$4.7 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, specified financial measures consisting of the Net Debt to Adjusted EBITDA Ratio and Net Debt to Capitalization Ratio. We define 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. The components of the ratios include Capitalization and Adjusted EBITDA. We define Capitalization as Net Debt plus Equity. We define Adjusted EBITDA as net earnings before finance costs, interest income, income tax expense (recovery), DD&A, exploration expense, goodwill impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), revaluation gain, re-measurement of contingent payment, gains (losses) on divestiture of assets, other income (loss), net and share of income (loss) from equity-accounted investees calculated on a trailing 12-month basis. These ratios are used to steward our overall debt position and as measures of our overall financial strength.

See the Specified Financial Measures Advisory of this MD&A.

	2021	2020	2019
Net Debt to Capitalization Ratio (percent)	**29**	30	25
Net Debt to Adjusted EBITDA Ratio (times)	**1.2x**	11.9x	1.6x

Our Net Debt to Adjusted EBITDA Ratio Target is between 1.0 to 1.5 times at the bottom of the cycle, which we see as approximately US$45 per barrel WTI. This ratio may fluctuate periodically outside the range due to factors such as persistently high or low commodity prices. Our objective is to maintain a high level of capital discipline and manage our capital structure to help ensure we have sufficient liquidity through all stages of the economic cycle. To ensure financial resilience, we may, among other actions, adjust capital and operating spending, draw down on our credit facilities or repay existing debt, adjust dividends paid to shareholders, purchase our common shares for cancellation, issue new debt, or issue new shares.

On December 31, 2020, before the Arrangement, our Net Debt to Capitalization Ratio was 30 percent. Our Net Debt to Capitalization Ratio increased as a result of the Arrangement. Ongoing reductions in Net Debt, described in the Cash From (Used In) Financing Activities above, lowered our Net Debt to Capitalization Ratio to 29 percent on December 31, 2021.

As at December 31, 2021, our Net Debt to Adjusted EBITDA Ratio was 1.2 times. Our Net Debt to Adjusted EBITDA Ratio decreased compared with December 31, 2020 as a result of higher Operating Margin in 2021, partially offset by an increase in our Net Debt acquired as part of the Arrangement. See the Operating and Financial Results section of this MD&A for more information on Net Debt.

We are in compliance with all of the terms of our debt agreements. Under the terms of our committed credit facility, we are required to maintain a total debt to capitalization ratio, as defined in the agreements, not to exceed 65 percent. We are well below this limit. 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

Under the Arrangement, we acquired all the issued and outstanding Husky common shares in consideration for the issuance of 0.7845 Cenovus common shares plus 0.0651 Cenovus Warrants for each Husky common share. We issued 788.5 million Cenovus common shares with a fair value of $6.1 billion, based on the December 31, 2020, closing share price of $7.75, as reported on the TSX. In addition, 65.4 million Cenovus Warrants were issued. Each whole warrant entitles the holder to acquire one Cenovus common share for a period of five years at an exercise price of $6.54 per share. The fair value of the warrants was estimated to be $216 million. We also acquired all the issued and outstanding Husky preferred shares in exchange for 36.0 million Cenovus first preferred shares with substantially identical terms and a fair value of $519 million.

We have a number of stock-based compensation plans which include stock options with associated net settlement rights, performance share units ("PSUs"), restricted share units ("RSUs") and deferred share units ("DSUs"). In connection with the Arrangement, at the closing of the transaction on January 1, 2021, outstanding Husky stock options were replaced by Cenovus replacement stock options ("Cenovus Replacement Stock Options"). Each Cenovus Replacement Stock 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. The fair value of the replacement stock options was estimated to be $9 million.

As at December 31, 2021, there were approximately 2,001 million common shares outstanding (December 31, 2020 — 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 plans and our PSU, RSU and DSU Plans.

Our outstanding share data is as follows:

As at February 4, 2022	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares [1]	**1,995,284**	**N/A**
Common Share Warrants	**63,750**	**N/A**
Series 1 Preferred Shares	**10,740**	**N/A**
Series 2 Preferred Shares	**1,260**	**N/A**
Series 3 Preferred Shares	**10,000**	**N/A**
Series 5 Preferred Shares	**8,000**	**N/A**
Series 7 Preferred Shares	**6,000**	**N/A**
Stock Options [1]	**37,559**	**23,414**
Other Stock-Based Compensation Plans	**14,515**	**1,371**

(1) Includes Cenovus Replacement Stock Options (defined above) issued pursuant to the Arrangement in replacement of all issued and outstanding Husky stock options.

Common Share Dividends

In 2021, we paid dividends of $176 million or $0.0875 per common share (2020 – $77 million or $0.0625 per common share). The declaration of dividends is at the sole discretion of Cenovus's Board and is considered quarterly. The Board declared a first quarter dividend of $0.035 per common share, payable on March 31, 2022 to common shareholders of record as of March 15, 2022.

Cumulative Redeemable Preferred Share Dividends

In 2021, dividends of $34 million, were paid on the series 1, 2, 3, 5 and 7 preferred shares. The declaration of preferred share dividends is at the sole discretion of Cenovus's Board and is considered quarterly. The Board declared a first quarter dividend on the series 1, 2, 3, 5 and 7 preferred shares, payable on March 31, 2022, in the amount of $9 million.

Capital Investment Decisions

Our 2022 capital program is forecast to be between $2.6 billion and $3.0 billion. Our Future Capital Investment is focused on maintaining safe and reliable operations, while positioning the Company to drive enhanced shareholder value to deliver upstream production of approximately 800.0 thousand BOE per day and downstream throughput of approximately 555.0 thousand barrels per day.

Adjusted Funds Flow and Free Funds Flow

Adjusted Funds Flow is a non-GAAP financial 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 and is the starting point for calculating Free Funds Flow. Free Funds Flow is a non-GAAP financial measure used to assist in measuring the available funds the Company has after financing its capital programs.

($ millions)	**2021**	2020	2019
Cash From (Used in) Operating Activities	**5,919**	273	3,285
Adjusted Funds Flow (1)	**7,248**	117	3,670
Total Capital Investment	**2,563**	841	1,176
Free Funds Flow (1)	**4,685**	(724)	2,494
Cash Dividends	**210**	77	260
	4,475	(801)	2,234

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory section of this MD&A. Comparative figures have been restated to conform with the definition in this MD&A.

Our approach on the financial framework remains consistent. We will continue to evaluate all opportunities based on a US$45 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 allocate our Free Funds Flow towards debt reduction, and further increase returns to shareholders as Net Debt targets are reached.

Contractual Obligations and Commitments

We have obligations for goods and services entered into in the normal course of business. Commitments are primarily related to transportation agreements and obligations that have original maturities of less than one year are excluded. For further information, see the Consolidated Financial Statements.

The Arrangement resulted in the assumption of non-cancellable contracts and other commercial commitments. On January 1, 2021, we assumed total commitments of $17.6 billion, of which $7.4 billion were for various transportation commitments. Transportation commitments include $1.7 billion that are subject to regulatory approval or have been approved but are not yet in service.

As at December 31, 2021 ($ millions)	2022	2023	2024	2025	2026	Thereafter	**Total**
Commitments							
Transportation and Storage (1)	3,288	3,567	3,373	2,146	2,012	16,600	**30,986**
Real Estate (2)	44	43	52	54	57	658	**908**
Obligation to Fund Equity-Accounted Affiliate (3)	68	85	99	90	90	210	**642**
Other Long-Term Commitments	509	156	145	136	150	1,214	**2,310**
Total Commitments (4)	3,909	3,851	3,669	2,426	2,309	18,682	**34,846**
Other Obligations							
Long-term Debt (Principal and Interest) (5)	561	713	895	2,128	475	14,892	**19,664**
Decommissioning Liabilities	231	329	569	678	426	4,629	**6,862**
Contingent Payment	238	—	—	—	—	—	**238**
Lease Liabilities (Principal and Interest) (6)	453	410	384	322	312	3,192	**5,073**
Total Commitments and Obligations	5,392	5,303	5,517	5,554	3,522	41,395	**66,683**

(1) Includes transportation commitments of $8.1 billion (December 31, 2020 – $14.0 billion) that are subject to regulatory approval or have been approved, but are not yet in service. Terms are up to 20 years subsequent to the date of commencement.

(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) Relates to funding obligations to HCML.

(4) Commitments are reflected at Cenovus's proportionate share of the underlying contract.

(5) On January 10, 2022, the Company announced its intention to redeem the entire outstanding balance of its 3.80 percent notes and 4.00 percent unsecured notes on February 9, 2022. Long-term debt maturities above have not been adjusted for this redemption.

(6) Lease contracts related to office space, our retail and commercial network, railcars, storage assets, drilling rigs and other refining and field equipment.

Our total commitments were $34.8 billion as at December 31, 2021, of which $31.0 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.

Our commitments with HMLP at December 31, 2021, include $2.6 billion related to transportation, storage and other long-term contracts.

As at December 31, 2021, outstanding letters of credit issued as security for performance under certain contracts totaled $565 million (December 31, 2020 – $441 million).

Legal Proceedings

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

Transactions with Related Parties

Transactions with HMLP are related party transactions as we have a 35 percent ownership interest in HMLP. As the operator of the assets held by HMLP, we provide management services for which we recover shared service costs. We are also the contractor for HMLP and construct its assets on a cost recovery basis with certain restrictions. For the year ended December 31, 2021, we charged HMLP $243 million for construction and management services.

We pay an access fee to HMLP for the use of its pipeline systems that are used by our blending business. We also pay HMLP for transportation and storage services. For the year ended December 31, 2021, we incurred costs of $284 million for the use of HMLP's pipeline systems, as well as transportation and storage services.

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, our business, reputation, financial condition, results of operations and cash flows, which may reduce or restrict our ability to pursue our strategic priorities, meet our targets or outlooks, goals, initiatives and ambitions, 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 our risks and is integrated with the Cenovus Operations Integrity Management System ("COIMS"). 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 the Cenovus risk matrix. 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 semi-annual risk reports presented to our 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, reputation, access to capital, cost of borrowing, access to liquidity, ability to fund dividend payments and/or business plans and the market price of our securities. These factors should be considered when investing in securities of Cenovus.

Pandemic Risk

The COVID-19 pandemic (including the emergence of variant strains of COVID-19), and measures taken in response by governments and health authorities around the world has created ongoing uncertainty that has resulted in, and may continue to result in restrictions on movement and businesses being maintained, re-imposed or imposed on a stricter basis, which could 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 our employees, customers, partners and business or when economic activity will normalize.

The COVID-19 pandemic may increase our exposure to, and the magnitude of, each of the risks identified in this Risk Management and Risk Factors section of this MD&A and identified in other documents we file with securities regulators from time to time. 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, be adversely impacted as a result of the pandemic and/or a 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 circumstances including, but not limited to: workforce disruptions or labour shortages caused by workers becoming infected with COVID-19; challenges to COVID-19 safety protocols implemented by Cenovus; government or health authority mandated restrictions on travel by workers, which may impact cross-border business travel and travel to remote worksites; closure of our facilities, workforce camps or worksites, or those on which we rely; increased worker attrition and health-related leaves and absences from work impacting operations.
- 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 program;
- Reduced demand for commodities and reduced commodity prices resulting in reductions in the volumes and value of our reserves (see "Commodity Prices" below).
- Commodity storage and transportation 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 to otherwise get crude oil, refined products or natural gas 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 or privacy breach arising from the number of employees, customers and partners working and accessing our systems remotely.
- 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 or commodity prices and/or a change in market fundamentals.

The extent to which the COVID-19 pandemic impacts our business, results of operations and financial condition will depend on future developments, which are highly uncertain and are difficult to predict with any degree of precision, including, but not limited to: the severity, duration, spread or resurgence of COVID-19 and its variants; the timing, extent and effectiveness of actions taken to contain or treat COVID-19 and its variants, including the availability, distribution rate, effectiveness and public uptake of any vaccines or boosters; and the speed at which, and extent to which, normal economic and operating conditions resume. The potential impacts of the COVID-19 pandemic to our business, results of operations and financial condition could be more significant in the current year as compared with 2020 and 2021. The COVID-19 pandemic has resulted in, and may continue to result in, significant market uncertainty, including substantial fluctuations in commodity prices, currency exchange rates, inflation, interest rates, counterparty credit and performance risk, and general levels of investing and consumption. 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 COVID-19 pandemic may have, and, as a result, the ultimate impact of the COVID-19 pandemic is highly uncertain and subject to change. Management does not yet know the full extent of the impact on our business, operations and financial condition or on 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 federal, provincial, territorial, state, regional and municipal governments and public health officials and have implemented COVID-19 testing protocols for staff accessing our high occupancy worksites and workforce camps. 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 and the corresponding measures we take, may result in new legal challenges and disputes, including, but not limited to, class action claims.

Financial Risk

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, but not limited to, compliance or non-compliance with quotas agreed upon by OPEC members and decisions by OPEC not to impose production quotas on its members; prices and availability of alternate sources of energy; actions of domestic or foreign governments or regulatory bodies that may impact commodity prices; 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); economic conditions; outbreak of war; outbreak or continuation of a pandemic; terrorist threats; technological developments; the occurrence of natural disasters; and weather conditions.

The financial performance of our oil sands operations 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 and 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 to medium crude oil and heavy crude oil which, along with higher diluent costs, can adversely affect our financial condition.

Our natural gas and NGL production is currently located in Western Canada and Asia Pacific. Natural gas and NGL prices are impacted by a number of factors, including, but not limited to: global and regional supply and demand for natural gas and NGLs; market competitiveness; developments related to the market for liquefied natural gas; prices and availability of alternate sources of energy; actions of domestic or foreign governments or regulatory bodies that may impact commodity prices; enforcement of government or environmental regulations; public sentiment towards the use of non-renewable resources, including natural gas and NGLs; political stability and social conditions in natural gas and NGL-producing countries; market access constraints and transportation interruptions (pipeline, marine or rail); economic conditions; technological developments; outbreak or continuation of a pandemic; terrorist threats; 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, including the United States Renewable Fuel Standard ("RFS") and other regulations pertaining to the production and use of refined products and non-renewable resources; emissions, including carbon, market pricing and the accessibility and liquidity of such markets; 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; outbreak or continuation of a pandemic; the occurrence of natural disasters; and weather conditions.

The financial performance of our refining operations is also 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 levels change 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, results of operations, cash flows and financial condition.

In addition, and relating to the level of future demand (and corresponding price levels) for each of crude oil, refined products, natural gas and NGLs, 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 both cost and 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. See "Foreign Exchange Rates" below.

Fluctuations in the commodity prices, 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, unutilized long-term transportation commitments and/or low utilization levels at our 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, may have a material impact on our business, financial condition, results of operations, cash flows or reputation and 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 our committed credit facility. In certain instances, we will use derivative instruments to manage exposure to price volatility on a portion of our 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.

Hedging Activities

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

These hedging activities may expose 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 poorly correlated to the change in the valuation of the underlying exposures being hedged; change in price of the underlying commodity or market value of the instrument; lack of market liquidity; insufficient counterparties to transact with; counterparty default; deficiency in systems or controls; human error; the unenforceability of contracts.

There is risk that the consequences of hedging to protect against the possibility of unfavourable market conditions may limit the benefit to us of changes in commodity prices, interest rates and foreign exchange rates. We may also suffer financial loss due to hedging arrangements if we are unable to fulfill our delivery obligations related to the underlying physical transaction. These risks are managed through hedging limits authorized under our *Market Risk Management Policy*.

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 2021, 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 transport and store rather than sell our physical crude oil and condensate volumes as well as hedging activity related to the transportation of crude and condensate. We use our marketing and transportation initiatives, including storage and pipeline assets, to optimize product mix, delivery points, transportation commitments and customer diversification, and 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 for the year ended December 31, 2021 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.

The following table summarizes the sensitivities of the fair value of our risk management positions to fluctuations in commodity prices and foreign exchange rates, 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:

As at December 31, 2021	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$5.00/bbl Applied to WTI, Condensate and Related Hedges	**(225)**	**225**
WCS and Condensate Differential Price	± US$2.50/bbl Applied to WCS and Differential Hedges Tied to Production	**4**	**(4)**
Refined Products Commodity Price	± US$5.00/bbl Applied to Heating Oil and Gasoline Hedges	**(2)**	**2**
U.S. to Canadian Dollar Exchange Rate	± 0.05 in the U.S. to Canadian Dollar Exchange Rate	**11**	**(12)**

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

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 and also in connection with our hedging activities, acquisitions and dispositions. 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 business, results of operations or financial condition.

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, significant unanticipated expenses, or a change in law, market fundamentals, our credit ratings, business operations, or investor or lender sentiment or policy may impede our ability to secure and maintain cost-effective financing. An inability to access capital, on terms acceptable to us 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 resulting in a material adverse effect on our business, 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, regulatory, 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, we 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 facility capacity, and accessing the capital markets.

We are required to comply with various financial and operating covenants under our credit facility 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 but not limited to, 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 to maintain our 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. A portion of our long-term sales contracts in Asia Pacific are priced in RMB. An increase in the value of the Canadian dollar relative to the RMB will decrease the revenues received in Canadian dollars from the sale of natural gas commodities in the region.

Interest Rates

Fluctuations in interest rates as a result of the use of floating rate securities or borrowings may affect our cash flow and financial results. An increase in interest rates could increase our net interest expense and affect how certain liabilities are recorded, both of which could negatively impact our cash flow and 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 Purchase of Securities

The payment of dividends, continuation of our dividend reinvestment plan and any potential purchase by Cenovus of our securities is at the discretion of our Board, and is dependent upon, among other things, financial performance, debt covenants, satisfying solvency tests, 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 Internal Control Over Financial Reporting ("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 Considerations (Safety, Environment and Reliability)

Our operations are subject to risks generally affecting the energy industry and 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 on and offshore 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 in the jurisdictions in which we conduct our business. These risks include but are not limited to: the effects of government actions or regulations, policies and initiatives; 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; releases or spills, including releases or spills from offshore operations, shipping vessels or other marine transport incidents; uncontrollable flows of crude oil, natural gas or well fluids; failure to follow operating procedures or operate within established operating parameters; adverse weather conditions; corrosion; pollution; freeze-ups and other similar events; the breakdown or failure of equipment, pipelines and facilities, information technology and systems and processes; regular or unforeseen maintenance; the performance of equipment at levels below those originally intended; 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 such party'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; 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.

If any such risks materialize, they may interrupt operations, impact our reputation, cause loss of life or personal injury, result in loss of or damage to equipment, property, information technology and control systems, related data, cause environmental damage that may include polluting water, land or air, and may result in regulatory action, fines, penalties, civil suits, or criminal or regulatory charges against us, any of which may have a material adverse effect on our business, financial condition, results of operations, cash flows, and reputation.

In addition, 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.

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, 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. 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 operations and cash flows.

Aviation Incidents

Our Offshore operations rely on regular travel by helicopter. A helicopter incident resulting in injury, loss of life, facility shutdown or regulatory action could have a material adverse effect on our operations and reputation. 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 our internal and industry standards with respect to aviation safety. Additional measures specific to our challenging operating environments are specified in our design requirements and pilot training is aligned with industry best practices.

Ice Management

Although extensive measures are in place to prevent incidents related to sea ice and icebergs, our Atlantic operations offshore Newfoundland and Labrador 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. Our Atlantic operations have a robust ice management program. We have policies in place to protect people, equipment and the environment in the event of extreme weather conditions and adverse ice conditions, including Adverse Weather Guidelines for the SeaRose FPSO. We continue to manage physical risk through engineering for extreme weather events.

Market Access Constraints and Transportation Restrictions

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

Interruptions or restrictions in the availability of these pipeline, terminals, 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 if supply into the system exceeds the infrastructure capacity. There can be no certainty that investments in new pipeline projects will be made by applicable third-party pipeline providers, that any applications to expand capacity will receive the required regulatory approvals, or that any such approvals will result in the construction of the pipeline project, or that such projects would provide sufficient transportation capacity.

There is no certainty that 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 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 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 by-rail and/or marine transport or the economics associated with rail or marine 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.

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. Exploring for, developing or acquiring reserves is capital intensive. To the extent our cash flow is insufficient to fund capital expenditures and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our crude oil and natural gas reserves will be impaired. In addition, we may be unable to find and develop or acquire additional reserves to replace our crude oil and natural gas production at acceptable costs.

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 attempts 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

Development, operating and construction 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; interruptions to existing market access infrastructure; failure to maintain quality construction and manufacturing standards; equipment limitations, including the cost or availability of oil and gas field equipment, commodity prices, higher SORs in our Oil Sands operations, additional government or environmental regulations and supply chain disruptions, including access to skilled labour. While we do not believe that inflation has had a material effect on our business, financial condition or results of operations to date; if our development, operation or labour costs were to become subject to significant inflationary pressures, we may not be able to fully offset such higher costs through corresponding increases in commodity prices. Our inability to manage costs or to secure equipment, materials or skilled labour necessary to our exploration, development, construction and operations for the expected price, on the expected timeline, or at all, could have a material 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 and refiners may develop and implement 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

We manage a variety of oil, natural gas and refining projects across our global portfolio of assets, 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 our 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 supply chain disruptions; 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 expenditures and expenses; our ability to source or complete strategic transactions; the effect of the COVID-19 pandemic 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 licence 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 our future demands or expectations 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 we could be partially or totally liable for our partner’s share of the project. Should one of our partners become insolvent, we may similarly be directed by applicable regulators to carry out obligations on behalf of our partner and may not be able to obtain reimbursement for these costs, which could have a material adverse effect on our financial condition, results of operations, reputation and cash flows.

SAGD Technology

Current technologies used for the recovery of bitumen is 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 recovery process varies and therefore impacts costs. The performance of the reservoir affects 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.

Technology, Information Systems and Privacy

We rely heavily on technology, including operating technology and information technology, to effectively operate our business. This may include on premise systems, (such as networks, computer hardware and software), networks and telecommunications systems, mobile applications, and cloud services. Such systems and services may be provided by third parties. In the event we are unable to regularly and effectively access, use, rely upon, secure, upgrade, and take other steps to maintain or improve the efficiency and efficacy of such systems and services, the operation of such systems and services could be interrupted, resulting in operational interruptions or the loss, corruption, or release of data.

In the ordinary course of business, we collect, use and store sensitive data, including intellectual property, proprietary and business information and personal information, including the information of third parties. Despite our security measures, our technology systems and services may be vulnerable to attacks (such as by hackers, cyberterrorists or other third parties) or to disruption due to staff or third-party error or malfeasance or to other disruptions, including as a result of natural disasters and acts of state or industrial espionage, activism, terrorism or war. Any such incident could compromise information used or stored on our systems or services and result in the loss, theft, inability to access, use or rely upon, the unauthorized access, disclosure, copying, use, modification, disposal or destruction of, or the exposure of, internal, confidential, personal or other sensitive information including information related to our assets and operations, technology, intellectual property, corporate or retail credit card information, customer personal information, employee personal information, exploration activities, corporate actions, executive officer communications and financial results. These 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.

Without limiting the foregoing, these risks include the risk of cyber-related fraud or attacks whereby threat actors attempt to circumvent electronic communications controls or attempt to impersonate internal personnel or business partners to divert payments and financial assets to accounts controlled by the perpetrators or to introduce ransomware into one or more systems or services in an effort to extract a payment. If a threat actor is successful in bypassing our cyber-security measures and business process controls, such cyber-related risks could result in financial losses, remediation and recovery costs, and an adverse reputational impact.

Data protection and privacy is governed by a complex legal and regulatory framework that is rapidly evolving in the areas in which we operate. Such legislation applies to a wide range of data processing activities including, but not limited to, processing personal information. For example, effective November 1, 2021, the Personal Information Protection Law (“PIPL”) became effective in the People's Republic of China. PIPL is China's first comprehensive law designed to regulate online data and protect personal information. In addition, on September 1, 2021, the Data Security Law went into effect in the People's Republic of China. Such legislation applies to a wide range of data processing activities including, but not limited to, processing personal information. With extraterritorial scope and severe fines and penalties, these evolving laws impose an increasingly complex and comprehensive legal framework for the collection, use and processing of personal information. Compliance with such legislation may result in increased operating costs and failure to comply with such legislation may result in severe fines and penalties, each of which may adversely impact our financial condition, results of operations and cash flows.

Security and Terrorist Threats

Security threats and terrorist or activist activities may impact our personnel, or those of partners, customers, and suppliers, and could result in situations of injury, loss of life, extortion, hostage situations and/or kidnapping or unlawful confinement, destruction or damage to property of Cenovus or others, impact to the environment, and business interruption. 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 systems, services, infrastructure, market access routes, or partnerships 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 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.

Activism and Disruptions to Operations

Increasing public engagement and activism generally, and in connection with the energy industry and the continued development of fossil fuel-based energy, has, from time to time, resulted in temporary disruptions to oil and gas development, operations and transportation. Such opposition has not yet materially impacted our facilities directly; however, activist groups and individuals may engage in protests, demonstrations or blockades that may disrupt our facilities or operations, or to facilities or operations on which we rely. Any such disruptions may have an adverse impact on our business, operations, financial condition or reputation.

While we have systems, policies and procedures designed to prevent or limit the effects of such disruptive events, there can be no assurance that these measures will be sufficient and that such disruptions will not occur or, if they do occur, that they will be adequately addressed in a timely manner.

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 attract and retain new talent with the necessary leadership, professional and technical competencies, it could have a material adverse effect on our business, financial condition and results of operations.

Litigation

From time to time, we may be involved in demands, disputes and litigation arising out of or related to our operations. Claims and related litigation may be material. Due to the nature of our operations we may experience various types of claims including, but not limited to, 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, privacy and employment-related matters. We may be required to incur significant expenses or devote significant resources in defending against any such litigation, which could result in an unfavourable decision, including fines, sanctions, monetary damages, temporary or permanent suspensions of operations, or the inability to engage in certain 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” below.

Indigenous Land and Rights Claims

Opposition by Indigenous people to our company, our operations, development or exploration in the jurisdictions in which we conduct business may adversely impact us. Such impacts include impacts to our reputation, relationship with host governments, local communities and other Indigenous communities, diversion of Management’s time and resources, increased legal, regulatory and other advisory expenses, and could adversely impact our progress and ability to explore, develop and continue to operate properties.

Some Indigenous groups have established or asserted Indigenous and treaty 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. Some Indigenous groups have also brought private nuisance claims against project operators for infringement of Indigenous rights. Such claims, if successful, could adversely affect our business, results of operations, financial condition or reputation.

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 interests. 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 Canadian federal government passed legislation which requires it to take all necessary measures 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 have been and are expected to continue to 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.

Governmental Risk

Shifts in government policy by existing administrations or following changes in government in jurisdictions in which we operate or elsewhere can impact our operations and ability to grow our business. Restrictions on fossil fuel-based energy use, cross-border economic activity, and development of new infrastructure can impact our opportunities for continued growth. We are committed to working with all levels of government in the jurisdictions in which we operate to ensure our business benefits and risks are understood, and mitigation strategies are implemented; however, changes in government policy are largely out of our control and may adversely affect our business, results of operations, financial condition or reputation.

Regulatory Risk

The oil and gas industry and refining industry in general and our operations in particular are subject to regulation and intervention under international, federal, provincial, territorial, state, regional and municipal legislation in the countries in which we conduct operations, development or exploration 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; protection of certain species or lands; provincial and federal land use designations; the reduction of GHG and other emissions; the export of crude oil, natural gas and other products; the transportation of crude-by-rail, pipeline or marine transport; generation, handling, storage, transportation, treatment and disposal of hazardous substance; the awarding or acquisition of exploration and production rights, 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 petroleum refining sector in the U.S. has been and continues to be subject to intensive environmental regulations, oversight, and enforcement from both federal and state governments. Third-party NGOs and citizen groups can also directly enforce environmental regulations in the U.S. and have been active against the U.S. refinery sector for many years. Any changes to the regulatory regime, including the implementation of new regulations or the modification or changed interpretation 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, cash flows and reputation. To mitigate these risks, we have regulatory programs that cover stakeholder engagement, air emissions, water discharges, deep well operations, solid and hazardous waste management, spills, and legacy contamination issues.

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 or obtain on acceptable conditions 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 consultation, Indigenous consultation, consensus seeking and collaboration, 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 conditions on a timely basis on satisfactory terms could result in delays, abandonment or restructuring of projects and increased costs.

Abandonment and Reclamation Cost Risk

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

We maintain estimates of our A&R liabilities; however, 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. For our Atlantic offshore operations, 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.

In Alberta, the A&R liability regime includes the Orphan Well Fund, which is administered by the Orphan Well Association ("OWA") . The OWA administers orphaned assets and is funded through a levy imposed on licensees, including Cenovus, based on the licensees' 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. The OWA may seek additional funding for such liabilities from industry participants, including Cenovus.

In 2021, the AER introduced a new holistic licensee capability assessment which provides the AER additional discretion and criteria for the consideration of licence eligibility, transfer applications and the requirement to post security or carry out A&R work. In January 2022, the AER introduced requirements for licensees to spend minimum amounts annually on A&R work based on each licensee's portion of inactive well liability. A similar program is anticipated to be implemented in Saskatchewan in 2023.

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 these new requirements, including our potential counterparties. This may result in future insolvencies and additional orphaned assets. In addition, this may impact our 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.

We have an ongoing environmental monitoring program of owned and leased retail locations and perform remediation where required to comply with contractual and legal obligations. 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.

The impact on our business 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 exploration 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 we produce 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 we operate, 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 and may reduce the value of our associated assets.

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

On July 1, 2020, the new CUSMA entered into force, which is known in the United States as the United States-Mexico-Canada Agreement (or "USMCA"), replacing the North American Free Trade Agreement ("NAFTA"). 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 allows Canadian products to more easily qualify for duty-free treatment under the CUSMA 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 some uncertainty relating to the origin certification process remains as the required documentation is determined on a case-by-case basis, this is a promising 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

We depend 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 January 1, 2022, approximately 7.2 percent of our employees are represented by unions under collective bargaining agreements, which includes just over 50 percent of our U.S. workforce. At unionized worksites, there is risk that strikes or work stoppages can occur. Any strike or work stoppage may have a material adverse effect on our business, safety, reputation, financial condition, results of operations and cash flows.

During periods of contract negotiation, work stoppage mitigation and emergency operation plans come with significant additional expenditure to ensure continuity of operations in the event of a strike or work stoppage. In addition, we may not be able to renew or renegotiate collective bargaining agreements on satisfactory terms or at all and a failure to do so may increase our costs. Any renegotiation of our existing collective bargaining agreements may result in terms that are less favourable to us, which may materially and adversely affect our financial condition, results of operations and cash flows.

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. 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

We are exposed to the financial and operational risks associated with uncertain international relations. Our 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.

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 us 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 us to the effects of the changing U.S.-China and Canada-China relations, including escalating tensions and possible retaliations.

In response to foreign sanctions, China has enacted multiple blocking laws intended to diminish the effectiveness and impact of foreign trade sanctions. Specifically, China has enacted regulations granting itself the ability to unilaterally nullify the effects of certain foreign restrictions that are deemed to be unjustified to Chinese nationals and entities, which came into force on January 9, 2021. Additionally, on June 10, 2021, China enacted the Anti-Foreign Sanctions Law. The Anti-Foreign Sanctions Law grants the right to take corresponding countermeasures if a foreign country violates international law and basic norms of international relations or adopts discriminatory restrictive measures against Chinese nationals and entities, and interferes in China's internal affairs. The language of the Anti-Foreign Sanctions Law is very broad, and beyond the laws themselves, little guidance has been provided regarding how the blocking laws will be enforced by the Chinese government and effectuated through the private rights of action created by these laws. The breadth and lack of specificity of such laws create additional risk and uncertainty for foreign companies operating in China, as they may result in conflicting rules and regulations in home and host countries.

Although formal export restrictions imposed against China and Chinese entities (including the placement of CNOOC on the U.S. Department of Commerce's Entity List) have not so far had a material impact on our business activities in Asia, increased export restrictions on China and Chinese entities may limit the range of certain supplies to our operations in Asia and have an adverse effect on operational efficiency, results of operations, financial condition or reputation.

It is possible that additional related actions taken by the U.S. (and its trading partners and allies), Canada, China and other nations may limit or restrict foreign companies' ability to participate in projects and operate in certain sectors of the Chinese economy, including the energy sector. The nature, extent and magnitude of the effect of dynamic trade relations cannot be accurately predicted and may have a material adverse impact on our business, prospects, financial condition, and results of operations, cash flows, and reputation.

U.S. sanctions related to China do not currently prevent or significantly impair our offshore operations in Asia, but they could do so in the future, particularly if U.S. sanctions against CNOOC were to be expanded. 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 that may adversely impact our offshore operations in Asia.

Moreover, it is 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 and reputation.

In addition, we 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 condition.

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 condition. The timing, extent and fallout of the ongoing tensions between the U.S. and China, as well as Canada and China remain 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.

Our financial condition, 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 us 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 recently 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 fossil fuel-based energy, the conversion of energy usage to less carbon-intensive forms and the general migration of energy usage away from fossil fuel-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, we are not able to estimate at this time the degree to which climate change related regulatory, climatic conditions, and climate-related transition risks could impact our business, financial condition and results of operations. Our business, financial condition, results of operations, cash flows, reputation, access to capital and insurance, cost of borrowing, 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

We operate in several jurisdictions that regulate or have proposed to regulate GHG emissions, often with a view to transitioning to a lower-carbon economy. 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 and other contemplated legislation, including how they may be harmonized, make 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.

The Government of Canada has announced the carbon tax will increase to \$170/tonne CO_2e by 2030. To reach that level, the price imposed on carbon will rise from the 2022 rate of \$50/tonne CO_2e by \$15/tonne CO_2e each year until 2030. To the extent a province's carbon pricing system does not meet the federal stringency requirements, the federal "backstop" regulations apply. Most of our large emitting facilities operate in British Columbia, Alberta, Saskatchewan, or Newfoundland and Labrador where provincial carbon pricing regulations apply. These provincial programs are expected to continue to be deemed equivalent to the federal carbon pricing system.

The Government of Canada has implemented regulation to enable the reduction of methane emissions from the crude oil and natural gas sector by 40 percent to 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 are expected to come into force on January 1, 2023. Certain provinces have since implemented provincial methane regulations that have been found to be equivalent with federal requirements. The Government of Canada has announced an additional target to reduce oil and gas methane emissions by at least 75 percent below 2012 levels by 2030. More details on the specific actions that enable this level of emissions reduction are expected in the coming year.

The U.S. does not have federal legislation establishing targets for the reduction of, or setting individualized limits on, GHG emissions from our U.S. facilities. The RFS was created to reduce GHG emissions and risks from that program are described below. Additionally, 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 CO_2e emissions per year to report those emissions on an annual basis. In addition to reporting direct CO_2e emissions, the GHGRP requires refineries to estimate the CO_2e emissions from the potential subsequent combustion of the refinery's products. In early 2021, the U.S. rejoined the Paris Agreement and subsequently announced a 2030 target to reduce GHG emissions by 50 percent to 52 percent from 2005 levels. 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 us.

Low Carbon Fuel Standards

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

Environment and Climate Change Canada is expected to publish final regulations for the Clean Fuel Standard under the Canadian Environmental Protection Act, 1999, in the spring of 2022, with new regulations targeted to come into force in December 2022. The federal government has indicated that over time, the Clean Fuel Standard would replace the current Renewable Fuels Regulations, which requires producers and importers of transportation fuels to acquire a certain number of 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 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 EPA has implemented the RFS 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, must achieve compliance with targets set by the EPA by blending certain types of renewable fuel into transportation fuel, or by purchasing RINs from other parties on the open market.

Cenovus and our refinery operating partners comply with the RFS by blending renewable fuels manufactured by third parties and by purchasing RINs on the open market, where prices fluctuate. We cannot predict the future prices of RINs and renewable fuel blendstocks, and the costs to obtain the necessary RINs and blendstocks could be material. Our 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. We have an RFS program to help mitigate risk related to fluctuating RINs pricing.

Light-Duty Vehicle Greenhouse Gas Emission Standards

The U.S. EPA has finalized new fuel economy standards applicable to automakers. The rule mandates new federal GHG emissions standards for passenger cars and light trucks by setting fuel economy standards for Model Years 2023 through 2026. These standards are expected to result in average fuel economy label values of 40 miles per gallon. The EPA's stated intention for the rule is to prompt automakers to produce more electric vehicles and set a path to a zero-emissions transportation future. The EPA stated that it intends to initiate future rulemaking to establish multi-pollutant emissions standards for Model Year 2027 and beyond. The impact these standards may have on the future demand (and corresponding price levels) for our products is unknown and dependent upon a number of factors. See "Climate Change Transition – Demand and Commodity Prices" below.

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 business, financial condition or results of operations. 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 – Technology

We depend on, among other things, the availability and scalability of existing and emerging technologies to meet our business goals, including our ESG targets. Limitations related to the development, adoption and success of these technologies or the development of disruptive technologies could have a negative impact on our long-term business resilience.

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. Under certain aggressive low-carbon scenarios, potential demand erosion could contribute to commodity price fluctuations and structural commodity price declines. 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 increased decarbonization policies, the ability to develop adequate alternative 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, industrial activity, weather patterns and climate conditions. 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, NGLs and refined products.

Market Access

Opposition to new and expanded pipeline projects have been influenced by, among other things, concerns about GHG emissions associated with fossil fuel-based energy development and end-use combustion of fuels. Additional concerns about pipeline spills can create opposition to pipeline projects at a local level. Our inability to optimize market access for either the delivery of our production or refining feedstock may negatively impact our business, financial condition, cash flows and results of operations.

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 adequate or prudent insurance coverage may also be adversely affected in the event that investors, credit rating agencies, lenders and/or insurers adopt more restrictive decarbonization policies or through the general stigmatization of the oil and gas industry. 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. Additionally, certain financial institutions have taken actions or announced policies related to decarbonization of their loan portfolios. As a result, costs of financing could increase over time and we may not be able to refinance our debt, renew or extend credit facilities or procure additional financing at reasonable costs and interest rates, or at all. The future development of our business may be dependent upon our ability to obtain additional capital, including debt and equity financing. See “Credit, Liquidity and Availability of Future Financing” above.

Accuracy of Climate Scenarios and Assumptions

We integrate the potential impact of GHG regulations and the cost of carbon at various price levels into our business planning processes. To mitigate uncertainty surrounding future emissions regulation, we evaluate our development plans under a range of carbon-constrained scenarios. We have considered the International Energy Agency (“IEA”) scenarios in our strategic planning for several years and also conduct ongoing assessments of both public and private scenarios. Although management believes that our climate-related estimates are reasonable, aligned with current, pending and potential future regulations, and informed by the IEA's climate scenarios, they are based on numerous assumptions that, if false, may have a material adverse effect on our business, financial condition and results of operations. Specifically, climate-related estimates influence our financial planning and investment decisions. Since we plan and evaluate opportunities partially on the basis of climate-related estimates, variations between actual outcomes and our expectations may have a material adverse effect on our business, financial condition, results of operations, reputation and cash flows.

Shareholder Activism

Shareholder activism has been increasing generally and in the energy industry, and investors may from time to time attempt to effect changes to our business or governance, with respect to climate change or otherwise, whether by shareholder proposals, public campaigns, proxy solicitations or otherwise. Such actions could adversely impact our business by distracting our Board and employees from core business operations, requiring us to incur increased advisory fees and related costs, interfering with our ability to successfully execute on strategic transactions and plans and provoking perceived uncertainty about the future direction of our business. Such perceived uncertainty may, in turn, make it more difficult to retain employees and could result in significant fluctuation in the market price of our securities.

Transition Risks – Reputation and Public Perception of the Oil and Gas Sector

Development of fossil fuel-based energy, and in particular the Alberta oil sands, has received considerable attention on the subjects of environmental impact, climate change, GHG emissions and Indigenous reconciliation. 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 and stigmatization of the oil and gas sector, and in particular the oil sands industry, could lead to constrained access to insurance, liquidity and capital and changes in demand for our products, which may adversely impact our business, financial condition or results of operations.

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. See “Reputation Risk” below.

Climate Change – Physical Risks

Extreme climatic conditions may also have material adverse effects on our 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, our exploration, production and construction operations, and the operations of major customers and suppliers, can be affected by acute physical climate risks, such as floods, forest fires, earthquakes, hurricanes, and other extreme weather events or natural disasters. This may result in cessation or diminishment of production, delay of exploration and development activities or delay of plant construction.

Climate change may also increase the frequency of severe weather conditions that may adversely impact our operations, business and financial results. Specifically, our Atlantic operations may be impacted by severe weather conditions, 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 pose a risk to Atlantic oil production facilities. An operational incident involving an iceberg has the potential to result in spills, asset damage, and production disruption. Climate change may result in an increased level of risk resulting in increased or additional mitigation requirements.

Our other operations 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 Regulation Risks

All phases of our operations are subject to environmental regulation pursuant to a variety of federal, provincial, territorial, state, regional and municipal laws and regulations in the jurisdictions in which we operate (collectively, the "environmental regulations"). Environmental regulations provide that exploration areas, 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.

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

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, prosecution, and could adversely affect our reputation. The costs of complying with environmental regulations and remedying noncompliance issues may have a material adverse effect on our business, financial condition, results of operations and cash flows. The implementation of new environmental regulations or changes in interpretation or the modification of existing environmental regulations affecting the crude oil, natural gas, NGL and refining industry generally could reduce demand for our products as well as shift hydrocarbon demand toward relatively lower-carbon sources and affect our long-term prospects.

U.S. environmental regulations and aggressive enforcement from regulators present challenges and risks to our U.S. operations. New emission standards, more stringent water quality standards, and regulation of emerging containments such as Per- and Polyfluoroalkyl Substances ("PFAS") can increase compliance costs, require capital projects, lengthen project implementation times, and have an adverse effect on our business, financial condition, results of operations and cash flows. U.S. regulators currently are assessing whether PFAS should be characterized as a regulatory defined hazardous waste, which could lead to additional cleanup liability at U.S. sites. See "Water Regulation "below.

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 has 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 modification of 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 we operate that may result in adverse impacts including but not limited to capital investment related to retrofitting 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 exploration may create risk of increased costs and project development delays. The regulatory frameworks within the jurisdictions where we operate are constantly evolving and changing and may become more onerous or costly which may impede our ability to economically develop our resources. The extent and magnitude of any adverse impacts of changes to the regulatory framework on project development and operations cannot be estimated at this time.

The Impact Assessment Agency of Canada leads and coordinates federal impact assessments for all designated projects within Canada. Assessment considerations beyond the environment expressly include health, economic, social, and gender impacts, as well as considerations related to sustainability and Canada's climate change commitments. For as long as the Alberta provincial government maintains the cap on oil sands emissions in Alberta and the cap has not been reached, our in situ oil sands projects should be exempted from the application of the federal impact assessment system, provided a number of additional conditions are met. However, other types of projects would undergo a federal assessment, including those within our Atlantic operations.

Water Regulation

We utilize fresh water in certain operations, which is obtained under licenses issued within each respective jurisdiction's regulations. If water use fees increase, the terms of the licences change or there are reductions in 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 condition. 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.

Our U.S. refineries are subject to water discharge requirements that require treatment of wastewater prior to discharging. Permits for discharging water are renewed from time to time to incorporate new water quality standards and may require modifications and expansion of water treatment facilities at the sites. Pollutants such as selenium, total dissolved solids, arsenic, mercury and others may require advance wastewater treatment, and discharge levels will depend on the types of crude processed at our refineries. Non-compliance with permit limits can lead to enforcement actions by regulators including issuance of fines, orders to upgrade treatment plants, and suspension of operations. Federal and state regulators in the U.S. are currently addressing the emerging pollutant PFAS in water discharge permits by requiring installation of additional wastewater treatment units and requiring monitoring of PFAS in discharges.

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, territorial, state, regional 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 have experienced increased 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.

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 we are ultimately able to produce from our reserves.

Cenovus ESG Focus Areas, Targets and Ambitions

We have set ambitious, achievable targets for each of our five ESG focus areas, as discussed below, including reducing our absolute emissions, using less water, reclaiming more land, supporting Indigenous reconciliation and increasing the number of women in leadership positions. To achieve these goals and to respond to changing market demand, we may incur additional costs and invest in new technologies and innovation. It is possible that the return on these investments may be less than we expect, which may have an adverse effect on our business, financial condition and reputation.

Generally speaking, our ESG targets and ambitions depend significantly on our ability to execute our current business strategy, 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 and ambitions, or a perception among key stakeholders that our ESG targets and ambitions are insufficient or unattainable, 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 and ambitions 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 we take in implementing targets and ambitions relating to our ESG focus areas may have a negative impact on our existing business and increase capital expenditures, which could have a negative impact on our future operating and financial results.

Climate and GHG Emissions Targets and Ambitions

We have set a target to reduce our absolute scope 1 and 2 GHG emissions by 35 percent by year-end 2035 from 2019 levels and have a long-term ambition to achieve net zero emissions from our operations by 2050. Our ability to meet our 2035 GHG reduction target and 2050 net zero ambition are subject to numerous risks and uncertainties and our actions taken in implementing such target and ambition 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, our 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 methane abatement and electrification initiatives in our Conventional segment; the purchase of renewable electricity; the unavailability of, or limited benefits from, technology that is expected to be commercially viable in the near term and its 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, and industry collaboration and innovation to find solutions to reduce costs and GHG emissions. 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 2035 GHG reduction target or 2050 net zero emissions ambition on the current timelines, or at all.

In addition, achieving our 2035 GHG reduction target and 2050 net zero ambition relies on a stable regulatory framework and will require capital expenditures and company resources, with the potential that actual costs may differ from our original estimates and the differences may be material. Furthermore, the cost of investing in emissions-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.

Water Stewardship Target

Our ability to reduce fresh water intensity by 20 percent in oil sands and in thermal operations by year-end 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.

Biodiversity Targets

Our biodiversity targets include the goal to reclaim 3,000 decommissioned well sites by year-end 2025 and to restore more habitat than we use within the Cold Lake caribou range by year-end 2030. Our ability to meet these targets is subject to various environmental and regulatory risks, which could impose significant costs, restrictions, liabilities and obligations on us. See "Abandonment and Reclamation Cost Risk" above. In addition, 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 biodiversity targets on the current timelines, or at all.

Indigenous Reconciliation Targets

Our Indigenous reconciliation targets to spend a minimum of $1.2 billion with Indigenous owned or operated businesses between 2019 and year-end 2025 and attain Progressive Aboriginal Relations gold certification from the Canadian Council for Aboriginal Business by year-end 2025 are subject to a number of financial, operational and efficiency risks relating to actions taken in implementing such targets.

In addition, a failure or delay in achieving our Indigenous reconciliation targets 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.

Inclusion and Diversity Targets

Our inclusion and diversity focus area includes a target of women in leadership roles of at least 30 percent by year-end 2030 and an aspiration for our Board to have at least 40 percent representation from women, Aboriginal peoples, persons with disabilities and members of visible minorities among non-management directors, including at least 30 percent women by year-end 2025. Efforts to meet such targets may increase the time and costs associated with appointing and replacing key personnel. Further, a failure or delay in achieving our targets may influence our reputation with our stakeholders, attract litigation and impact recruitment initiatives. There are also risks associated with the collection of certain personal data in furtherance of these targets, which is governed by federal, provincial and state privacy legislation.

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 climate change activist organizations and the public towards oil and gas operations. See "Transition Risks – Reputation and Public Perception of the Oil and Gas Sector" above.

Other Risks

Dilutive Effect

We are authorized to issue, among other classes of shares, an unlimited number of common shares for consideration and on terms and conditions as established by our Board without the approval of our shareholders in certain instances. Any future issuances of Cenovus common shares or other securities exercisable or convertible into, or exchangeable for, Cenovus common shares may result in dilution to present and prospective Cenovus shareholders. The issuance of additional Cenovus common shares upon exercise, from time to time, of securities convertible into Cenovus common shares 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, we will grant additional equity awards to our employees and directors under our compensation plans. These additional equity awards will have a further dilutive effect on our earnings per share, which could also negatively affect the market price of Cenovus common shares and may adversely impact the value of our shareholders' investments.

Risks Relating to Acquisitions

We have completed, and may complete in the future, one or more acquisitions for various strategic reasons including to strengthen our position and to create the opportunity to realize certain benefits. In order to achieve the benefits of any future acquisitions, we will be dependent upon our ability to successfully consolidate functions and integrate operations, procedures and personnel in a timely and efficient manner and to realize the anticipated growth opportunities and synergies from combining the acquired assets and operations with our existing assets and operations. The integration of acquired assets and operations requires the dedication of management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during the process. The integration process may result in the disruption of ongoing business and customer relationships that may adversely affect our ability to achieve the anticipated benefits of such acquisitions. Acquiring assets requires the assessment of reservoir and infrastructure characteristics, including estimated recoverable reserves, future production, commodity prices, revenues, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain and, as such, the acquired properties may not produce as expected, may not have the anticipated reserves and may be subject to increased costs and liabilities. Although the acquired assets are reviewed prior to completion of an acquisition, such reviews are not capable of identifying all existing or potentially adverse conditions. This risk may be magnified where the acquired assets are in geographic areas where we have not historically operated. Further, we may not be able to obtain or realize upon contractual indemnities from a seller for liabilities created prior to an acquisition and we may be required to assume the risk of the physical condition of the properties that may not perform in accordance with its expectations. See "Risks Related to the Arrangement" below.

Risks Relating to Dispositions

We have identified, and may identify in the future, certain assets for disposition. Specifically, we have entered into agreements to sell our Husky retail fuel network, our Tucker asset and our Wembley assets. Various factors could materially affect our ability to complete these announced transactions or to dispose of assets in the future, including stock exchange, regulatory, third-party and corporate approvals, counterparties' ability to fulfill their obligations under agreements to affect dispositions, commodity prices, the availability of purchasers willing to purchase certain assets at prices and on terms acceptable to us, associated asset retirement obligations, due diligence, favourable market conditions, and the assignability of joint venture, partnership or other arrangements. These factors may also reduce the proceeds or value to our business. We may also retain certain liabilities for or agree to indemnification obligations in a sale transaction. The magnitude of any such retained liabilities or indemnification obligations may be difficult to quantify at the time of the transaction and could ultimately be material. Further, certain third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after the sale of certain assets, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the purchaser of the assets fails to perform its obligations. Should any of the risk associated with dispositions materialize, it could have an adverse effect on our business, financial condition or reputation.

Risks Related to the Arrangement

Our Ability to Realize the Anticipated Benefits of the Arrangement by Integrating the Legacy Husky Operations

The process of integrating the legacy Husky operations into our business is ongoing. While much has been accomplished, the process is not yet complete and these efforts could result in disruption of existing relationships with suppliers, employees, customers and other stakeholders. There can be no assurance that management will be able to achieve all of the benefits that are expected to result from the Arrangement on the expected timelines, or at all.

The ongoing integration process involves numerous operational, strategic, financial, accounting, legal, tax and other risks and uncertainties associated with our business and operations, including the legacy Husky business. 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.

The ongoing integration process to realize all of the benefits of the Arrangement requires substantial management effort, time and resources which may divert Management's focus and resources from other strategic opportunities and operational matters and may result in increased attrition rates in the workforce (including the loss of key employees), the disruption of ongoing business and employee relationships, and increased employment-related claims and litigation, all of which may adversely affect our ability to achieve all of the anticipated benefits of the Arrangement.

Potential difficulties that may be encountered in the integration process include but are not limited to: (i) the inability to successfully integrate the businesses in a manner that permits us to achieve all of the anticipated revenue and cost savings on the expected timelines; (ii) complexities associated with managing a larger, more complex, multinational integrated business; (iii) integrating personnel at all levels of the company over multiple jurisdictions, effectively and efficiently; (iv) difficulties integrating and maintaining relationships with industry contacts and existing business partners associated with the legacy Husky operations, including the termination or modification of existing contractual relationships; and (v) the disruption of, or the loss of momentum in our business, including the legacy Husky business. Such challenges may prohibit us from successfully integrating the legacy Husky business or may materially delay the integration process. A failure to integrate the business on the expected timeline, may have an adverse effect on our financial condition, results of operations, and ability to realize the anticipated benefits of the Arrangement.

It is possible that the ongoing integration process could result in increased attrition levels generally or the loss of key employees to assist in the integration and operation of our businesses, which may exacerbate integration challenges. Difficulties or delays in the integration process or the inability to fully integrate the legacy Husky business 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 the Legacy Husky Operations

We may incur significant costs related to implementing ongoing integration plans, including facilities and systems consolidation costs and other employment-related costs. We will continue to assess the magnitude of these costs and additional unanticipated costs may be incurred in connection with the integration of the businesses. While we have 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. Any unanticipated costs and expenses related to the integration may have an adverse effect on our business, financial condition, results of operations and share price.

Potential Unforeseen Liabilities Associated with the Arrangement

The Arrangement and the operation of the legacy Husky operations may subject us to unforeseen or underestimated liabilities, including environmental and regulatory liabilities in Canada and other foreign jurisdictions. We may now be subject to or inherit claims related to the legacy Husky operations, including actions by 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 claims, and any associated litigation or regulatory proceedings, is uncertain and may negatively impact our financial condition, results of operations and reputation.

Risks Related to Significant Shareholders of Cenovus

As of December 31, 2021, Hutchison Whampoa Europe Investments S.à r.l. ("Hutchison") and L.F. Investments S.à r.l ("L.F. Investments") own 15.8 percent and 11.6 percent of our common shares, 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 or L.F. Investments into the market, either through open market trades on the TSX and NYSE 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 and L.F. Investments have entered into with Cenovus, or market perception regarding Hutchison or L.F. Investments' intention to sell Cenovus common shares, could adversely affect market prices for our 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 us in connection with the Arrangement, each of Hutchison and L.F. Investments may be able to impact certain matters requiring shareholder approval.

Market for Cenovus Warrants

There can be no assurance that an active public market for 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, but not limited to, fluctuations in our operating and financial results, the results of any public announcements made by us and our 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.

Contingent Payments Payable to ConocoPhillips

In connection with the Conoco Acquisition, we agreed to make contingent payments to ConocoPhillips 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 business, results of operations and financial condition.

Tax Laws

Income tax laws, regulations, and other laws or government incentive programs may in the future be changed or interpreted in a manner that adversely affects us, our financial results and our 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.

The international tax environment continues to change as a result of tax policy initiatives and reforms under consideration related to the Organisation for Economic Co-operation and Development's ("OECD") Base Erosion and Profit Shifting ("BEPS") project. Although the timing and methods of implementation vary, numerous countries including Canada have responded to the BEPS project by implementing, or proposing to implement, changes to tax laws and tax treaties, at a rapid pace. These changes may increase our cost of tax compliance and affect our business, financial condition and results of operations in a manner that is difficult to quantify. We will continue to monitor and assess potential adverse impacts on our global tax situation as a result of the BEPS project.

U.S. Tax Risk

On November 19, 2021, the U.S. House of Representatives passed the Build Back Better Act (the "Act"). The Act contains a number of social and environmental initiatives with a combined estimated cost of USD $1.75 trillion. The initiatives were primarily funded through various federal tax changes. On December 19, 2021, West Virginia's Senator Manchin formally voiced his opposition to the bill, thereby effectively stopping it before it was brought to a vote in the Senate. There is a possibility that portions of the Act will be resurrected in some form in a new bill and any tax changes contained therein could result in increased levels of U.S. taxation on our U.S. operations.

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 operations 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, as well as 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 Consolidated Financial Statements.

Joint Arrangements

The classification of a joint arrangement as either a joint operation or a joint venture requires judgment. The significant joint operations held by the Company are as follows:

- 50 percent interest in WRB Refining LP ("WRB LP").
- 50 percent interest in Sunrise Oil Sands Partnership ("SOSP").
- 50 percent interest in BP-Husky Refining LLC ("Toledo").

It was determined that Cenovus has the rights to the assets and obligations for the liabilities of WRB LP, SOSP and Toledo. As a result, the joint arrangements are classified as joint operations 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 original intention of the joint arrangements was to form an integrated North American heavy oil business. Partnerships are "flow-through" entities.
- The agreements require the partners to make contributions if funds are insufficient to meet the obligations or liabilities of the corporation and partnerships. The past and future development of WRB LP, SOSP and Toledo is dependent on funding from the partners by way of capital contribution commitments, notes payable and loans.
- WRB LP and SOSP have third-party debt facilities to cover short-term working capital requirements.
- SOSP is operated like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants in accordance with the partnership agreement. WRB LP and Toledo have very similar structures modified to account for the operating environment of the refining business.
- Cenovus, Phillips 66 and BP, as operators, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage, on the partners' behalf as the agreements prohibit the partners from undertaking these roles themselves. In addition, the joint arrangements do not have employees and, as such, are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

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 not reached a stage where technical feasibility and commercial viability can 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 Cash-Generating Units

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, 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.

Recoveries from Insurance Claims

The Company uses estimates and assumptions on the amount recorded for insurance proceeds expected to be received. Accordingly, actual results may differ from these estimated recoveries.

Functional Currency

The functional currency for each of the Company's subsidiaries is a management judgment based on the currency of the primary economic environment in which the subsidiary operates.

Fair Value of Related Party Transactions

The Company transacts with certain related parties, joint arrangements and associates in the normal course of business. Such relationships can have an effect on the financial results of the Company and may lead to differences in the transactions between related parties compared to transactions between unrelated parties. Independent opinions of the fair values may be obtained to confirm the estimated fair value of proceeds.

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 a novel strain 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 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 change assumptions used to determine the recoverable amount of the Company's PP&E and E&E assets and could affect the carrying value of those assets, may affect future development or viability of exploration prospects, may curtail the expected useful lives of oil and gas assets thereby accelerating depreciation charges and may accelerate decommissioning obligations increasing the present value of the associated provisions.

The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain. Environmental considerations are built into our estimates through the use of key assumptions used to estimate fair value including forward commodity prices, forward crack spreads and discount rates. The energy transition could impact the future prices of commodities.Pricing assumptions used in the determination of recoverable amounts incorporate markets expectations and the evolving worldwide demand for energy

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, GHG and emissions targets, water stewardship targets, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test recoverable amount 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.

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, quantity of reserves and resources, production costs, 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

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdiction. 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

In 2021, as a result of the close of the Arrangement, the Company updated its significant accounting policies including those around principles of consolidation, revenue recognition, employee benefit plans, related party transactions, cash and cash equivalents, PP&E, share capital and warrants and stock based compensation.

Principles of Consolidation

The Consolidated Financial Statements include the accounts of Cenovus and its subsidiaries. Subsidiaries are entities over which the Company has control. Subsidiaries are consolidated from the date of acquisition of control and continue to be consolidated until the date that there is a loss of control. All intercompany transactions, balances, and unrealized gains and losses from intercompany transactions are eliminated on consolidation.

Interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Joint operations arise when the Company has rights to the assets and obligations for the liabilities of the arrangement. The Company’s accounts reflect its share of the assets, liabilities, revenues and expenses from the Company’s activities that are conducted through joint operations with third parties. A portion of the Company’s activities relate to joint ventures, which are accounted for using the equity method of accounting.

An associate is an entity for which the Company has significant influence over but does not control or jointly control the affiliate. Investments in associates are accounted for using the equity method of accounting and are recognized at cost and adjusted thereafter to recognize the Company’s share of the affiliate’s profit or loss and other comprehensive income (“OCI”).

Revenue Recognition

Revenue is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. Cenovus recognizes revenue when it transfers control of the product or service to a customer, which is generally when title passes from the Company to its customer.

Purchases and sales of products that are entered into in contemplation of each other with the same counterparty are recorded on a net basis. Revenues associated with services provided as agent are recorded as the services are provided.

Cenovus recognizes revenue from the following major products and services:

- Sale of crude oil, NGLs and natural gas.
- Sale of petroleum and refined products.
- Crude oil and natural gas processing services.
- Pipeline transportation, the blending of crude oil and natural gas, and storage of crude oil, diluent and natural gas.
- Fee-for-service hydrocarbon trans-loading services.
- Construction services.

The Company satisfies its performance obligations in contracts with customers upon the delivery of crude oil, NGLs, natural gas, and petroleum and refined products, which is generally at a point in time. Performance obligations for crude oil and natural gas processing revenue, transportation services and trans-loading services are satisfied over time as the service is provided. Cenovus sells its production of crude oil, NGLs, natural gas, and petroleum and refined products generally pursuant to variable price contracts. The transaction price for variable price contracts is based on the commodity price, adjusted for quality, location and other factors. Revenue associated with natural gas processing, transportation services and trans-loading services are generally based on fixed price contracts.

Construction revenue is recognized for general contractor services that the Company provides to HMLP and includes fixed price and cost-plus contracts. Revenue from fixed price construction contracts is recognized as performance obligations are met and revenue from cost-plus contracts are recognized as services are performed.

The Company has take-or-pay contracts where Cenovus has long-term supply commitments in return for purchasers to pay for minimum quantities, whether or not the customer takes the delivery. If a purchaser has a right to defer delivery to a later date, the performance obligation has not been satisfied and revenue is deferred and recognized only when the product is delivered or the deferral provision can no longer be extended.

Cenovus's revenue transactions do not contain significant financing components and payments are typically due within 30 days of revenue recognition. The Company does not adjust transaction prices for the effects of a significant financing component when the period between the transfer of the promised goods or services to the customer and payment by the customer is less than one year. The Company does not disclose or quantify information about remaining performance obligations that have an original expected duration of one year or less and it does not have any long-term contracts with the exception of certain construction contracts with HMLP and take-or-pay contracts with unfulfilled performance obligations.

Employee Benefit Plans

The Company provides employees with a pension plan that includes either a defined contribution or defined benefit component.

Other post-employment benefit ("OPEB") plans are also provided to qualifying employees. In some cases, the benefits are provided through medical care plans to which the Company, the employees, the retirees and covered family members contribute. In some plans, benefits are not funded before retirement.

Pension expense for the defined contribution pension is recorded as the benefits are earned.

The cost of the defined benefit pension and OPEB plans are actuarially determined using the projected unit credit method. The amount recognized in other liabilities on the Consolidated Balance Sheets for the defined benefit pension and OPEB plans is the present value of the defined benefit obligation less the fair value of plan assets. Any surplus resulting from this calculation is limited to the present value of any economic benefits available in the form of refunds from the plans or reductions in future contributions to the plans.

Changes in the defined benefit obligation from service costs, net interest and remeasurements are recognized as follows:

- Service costs, including current service costs, past service costs, gains and losses on curtailments, and settlements, are recorded with pension benefit costs.
- Net interest is calculated by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period to the net defined benefit asset or liability measured. Interest expense and interest income on net post-employment benefit liabilities and assets are recorded with pension benefit costs in operating, and general and administrative expenses, as well as PP&E and E&E assets.
- Remeasurements, composed of actuarial gains and losses, the effect of changes to the asset ceiling (excluding interest) and the return on plan assets (excluding interest income), are charged or credited to equity in OCI in the period in which they arise. Remeasurements are not reclassified to net earnings in subsequent periods.

Pension benefit costs are recorded in operating, and general and administrative expenses, as well as PP&E and E&E assets, corresponding to where the associated salaries of the employees rendering the service are recorded.

From time-to-time, the Company may provide certain other long-term incentive benefits to employees. In 2019, a one-time incentive program was introduced whereby a cash award equivalent to the employee's base salary was payable if Cenovus achieved, prior to February 12, 2024, a target share price of $20 per share for a period of 20 consecutive trading days on the TSX (the "Plan"). In conjunction with the close of the Arrangement, the Plan was terminated and replaced with a synergy-focused incentive plan (the "Incentive Plan"). All employees, except for Executive Officers and some unionized employees are eligible. Under the Incentive Plan, a cash award of 15 percent to 30 percent of the employee's base salary is payable if Cenovus achieves greater than $1.0 billion in identified run-rate synergies prior to the end of 2022. The payout is calculated on a sliding scale and includes a performance multiplier for early achievement of synergy targets. The obligation related to the Incentive Plan is estimated as the probability of the payout being achieved multiplied by the expected payout amount. The obligation is recognized as general and administrative expense over the estimated time until payout is achieved.

Related Party Transactions

The Company enters into transactions and agreements in the normal course of business with certain related parties, joint arrangements and associates. Proceeds from the disposition of assets to related parties are recognized at fair value. Independent opinions of fair value may be obtained to confirm the estimated fair value of proceeds.

Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments with a maturity of three months or less. When outstanding cheques are in excess of cash on hand and short-term deposits, and the Company has the ability to net settle, the excess is reported in bank operating loans.

Cash and cash equivalents that are not available for use are classified as restricted cash. When restricted cash is not expected to be used within twelve months, it is classified as a non-current asset.

Property, Plant and Equipment

General

PP&E is stated at cost less accumulated DD&A, and net of any impairment losses. Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred. Land is not depreciated.

Any gains or losses from the divestiture of PP&E are recognized in net earnings.

Crude Oil and Natural Gas Properties

Development and production assets are capitalized on an area-by-area basis and include all costs associated with the development and production of crude oil and natural gas properties and related infrastructure facilities, as well as any E&E expenditures incurred in finding reserves of crude oil, NGLs or natural gas transferred from E&E assets. Capitalized costs include directly attributable internal costs, decommissioning liabilities and, for qualifying assets, borrowing costs directly associated with the acquisition of, the exploration for, and the development of crude oil and natural gas reserves.

For onshore assets, which includes assets from the Oil Sands and Conventional segments, costs accumulated within each area are depleted using the unit-of-production method based on estimated proved reserves determined using forward prices and costs. Offshore assets are depleted using the unit-of-production method based on estimated proved developed producing reserves or proved plus probable reserves determined using forward prices and costs. For the purpose of these calculations, natural gas is converted to crude oil on an energy equivalent basis. The unit-of-production method based on total proved reserves or total proved plus probable reserves takes into account any expenditures incurred to date together with future development costs to be incurred in developing those reserves.

Exchanges of development and production assets are measured at fair value unless the transaction lacks commercial substance or the fair value of either the asset received, or the asset given up, cannot be reliably measured. When fair value is not used, the carrying amount of the asset given up is used as the cost of the asset acquired.

Included in oil and gas properties are information technology assets used to support the upstream business and are depreciated on a straight-line basis over their useful lives of three years. Gross overriding royalty interests ("GORRs") in certain crude oil and natural gas properties are depleted using a unit-of-production method.

Manufacturing Assets

The initial costs of refining and upgrading PP&E are capitalized when incurred. Costs include the cost of constructing or otherwise acquiring the equipment or facilities, the cost of installing the asset and making it ready for its intended use, the associated decommissioning costs and, for qualifying assets, borrowing costs.

Refining assets are depreciated on a straight-line basis over the estimated service life of each component of the refinery. The major components are depreciated as follows:

- Land improvements and buildings: 15 to 40 years.
- Office improvements and buildings: 3 to 15 years.
- Refining equipment: 10 to 60 years.

The residual value, the method of amortization and the useful life of each component are reviewed annually and adjusted on a prospective basis, if appropriate.

Processing, Transportation and Storage Assets, Retail and Other

Depreciation for substantially all other PP&E is calculated on a straight-line basis based on the estimated useful lives of assets, which range from three to 60 years. The useful lives are estimated based upon the period the asset is expected to be available for use by the Company.

The residual value, the method of amortization and the useful life of the assets are reviewed annually and adjusted on a prospective basis, if appropriate.

Share Capital and Warrants

Common shares and preferred shares are classified as equity. Preferred shares are cancellable and redeemable only at the Company's option and dividends are discretionary and payable only if declared by Cenovus's Board of Directors. Transaction costs directly attributable to the issue of common shares and preferred shares are recognized as a deduction from equity, net of any income taxes. Dividends on common shares and preferred shares are recognized within equity. When purchased, common shares are reduced by the average carrying value with the excess of the purchase price recognized as a reduction in Cenovus's paid in surplus. Common shares are cancelled subsequent to being purchased.

Warrants issued in the Arrangement are financial instruments classified as equity and were measured at fair value upon issuance. On exercise, the cash consideration received by the Company and the associated carrying value of the warrants are recorded as share capital.

Stock-Based Compensation

Cenovus has a number of stock-based compensation plans which include stock options with associated net settlement rights ("NSRs"), Cenovus replacement stock options, PSUs, RSUs and DSUs. Stock-based compensation costs are recorded in general and administrative expenses, or recorded to PP&E or E&E assets when directly related to exploration or development activities.

New Accounting Standards and Interpretations not yet Adopted

There are new accounting standards, amendments to accounting standards and interpretations that are effective for annual periods beginning on or after January 1, 2022, and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2021. These standards and interpretations are not expected to have a material impact on the Company's 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, 2021. 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, 2021.

The effectiveness of our ICFR was audited as at December 31, 2021 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, 2021.

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

OUTLOOK

Energy markets have improved significantly in 2021. Successful global COVID-19 vaccine rollouts and solid economic growth have resulted in demand growth for crude oil and refined products, while generally the supply response has lagged. However, in the fourth quarter of 2021, the rapid rise of the Omicron variant and concerns that near-term supply could outpace demand has introduced crude oil and refined products market volatility. Early indications are that the Omicron variant is a milder variant that may not impact demand recovery significantly in the first quarter of 2022. The scale of resurgence and variants of COVID-19 is unpredictable and likely to result in market volatility into 2022. OPEC+ policy continues to support balancing the market. The group began to gradually unwind supply curtailments and is expected to increase production into 2022.

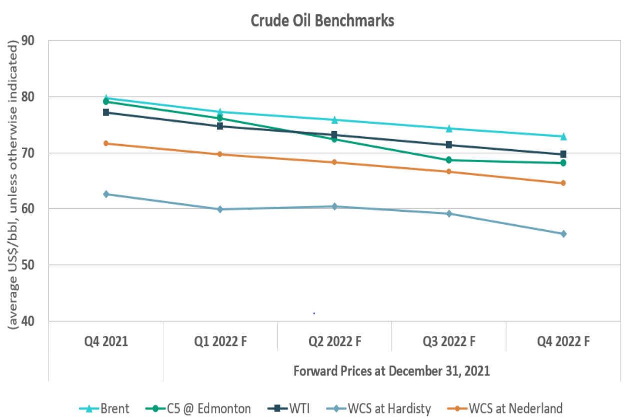
Our strategy is focused on delivering value over the long-term through sustainable, low-cost, diversified and integrated energy leadership. We aim to maximize shareholder value through premium cost structures and optimizing margins while delivering top-tier safety performance and ESG leadership. The Company prioritizes Free Funds Flow generation which enables debt reduction, increased shareholder returns through dividend growth and share buybacks, reinvestment in the business and diversification. We believe that maintaining a strong balance sheet will help Cenovus navigate through commodity price volatility.

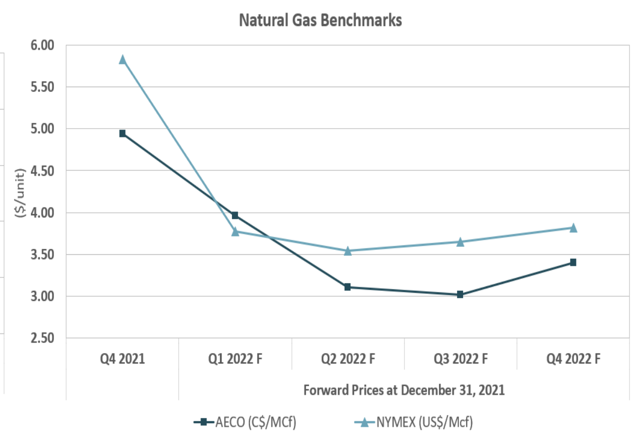
The following outlook commentary is focused on the next 12 months.

Commodity Prices Underlying our Financial Results

Our commodity pricing outlook is influenced by the following:

- We expect the general outlook for crude oil and refined product prices will be volatile and tied primarily to the supply and demand response to the current uncertain price environment, global demand impacts amid COVID-19 variant concerns and effectiveness of COVID-19 vaccines.
- The degree to which OPEC+ members (including Russia) continue to maintain crude oil production cuts, the rate they decide to increase production and the degree to which spare capacity exists to meet quotas.
- We expect that the WTI-WCS differential in Alberta will remain largely tied to the extent to which supply stays within export capacity, the completion of the Trans Mountain Expansion project and the level of crude-by-rail activity.
- Refining market crack spreads are likely to continue to fluctuate, adjusting for seasonal trends and refinery utilization in North America.

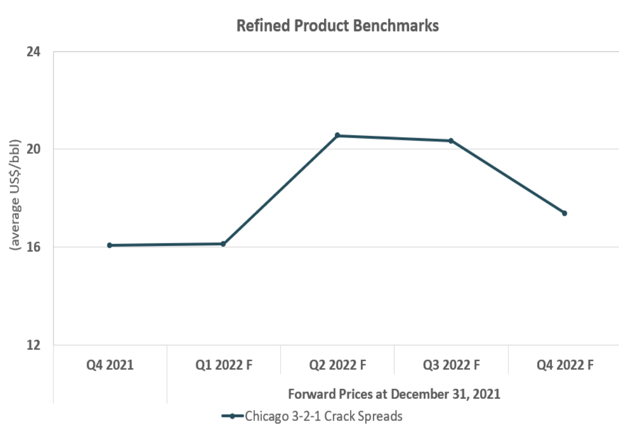


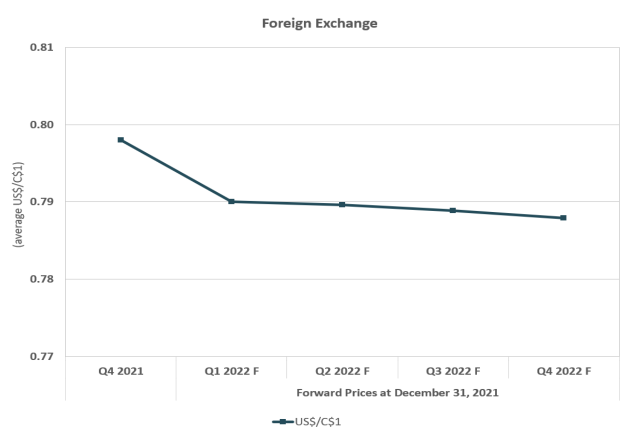


Natural gas prices rose significantly in 2021 compared to 2020. The forward curve shows that the market expects both Henry Hub and AECO prices to remain strong but below the highs in the fourth quarter of 2021. U.S. production has increased recently as a result of well completions, but continued growth will require drilling activity to increase further. Low coal stockpiles, strong gas generation and high liquified natural gas exports are supporting the market. Prices will continue to be impacted by weather throughout the year.

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.

We expect the Canadian dollar to continue to be impacted by 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.





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 in the USGC and Alberta, exposing Cenovus to the market crack spread in all of these markets.

Our WTI 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.
- Financial hedge transactions – limiting the impact of fluctuations in crude oil and refined product prices by entering into financial transactions related to our inventory price exposures.

Key Priorities for 2022

Our five key strategic objectives include delivering top-tier safety performance and ESG leadership; maximizing shareholder value through competitive cost structures and optimizing margins; maintaining and further reducing debt levels; a returns-focused capital allocation, incorporating increased shareholder returns that complement our business; and growing Free Funds Flow through pricing cycles.

Top Tier Safety Performance and ESG Leadership

Underpinning everything we do is the safety of our people and communities, and the integrity of our assets. We've identified safety along with corporate governance as our top value and foundational to our business, providing the backbone for all our operations. We will continue to promote a safety culture in all aspects of our work and use a variety of programs to always keep safety top of mind.

We are committed to demonstrating ESG leadership and continue to take concrete steps to earn our position as a global energy supplier of choice. In December 2021, Cenovus released targets representing our five ESG focus areas:

- Climate & GHG emissions.
- Water stewardship.
- Biodiversity.
- Indigenous reconciliation.
- Inclusion & diversity.

A path and program for achieving each target has been established, including identifying the levers and resources that will be required. These commitments are embedded in the five-year business plan to ensure business decisions are aligned with the targets. Additional information on management's efforts and performance across environmental, social and governance topics, including our ESG targets and plans to achieve them, are available in Cenovus's 2020 ESG report at cenovus.com.

As part of the integration of Cenovus and Husky we completed a policy harmonization initiative in 2021. Our updated Sustainability Policy, together with our revised Code of Business Conduct & Ethics, guides our actions and outlines our commitment to embedding environmental, economic and social considerations in our business decisions. We also formalized and published Human Rights and Indigenous Relations policies that reinforce our commitments, values and behaviours. Our directors, management and employees are annually required to complete policy training to review and commit to our Sustainability Policy, Code of Business Conduct & Ethics and a number of other key policies and standards.

Competitive Cost Structures and Optimizing Margins

We delivered our planned target of $1.2 billion in annual run-rate synergies by the end of 2021. 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 ways to improve efficiencies across Cenovus to drive incremental capital, operating and general and administrative cost reductions.

Maintaining and Further Reducing Debt Levels

Cenovus achieved its interim Net Debt Target of $10 billion in 2021. As at December 31, 2021, our Net Debt position was $9.6 billion. At December 31, 2021, long-term debt was $12.4 billion, and cash and cash equivalents was $2.9 billion. Through a combination of cash on hand and available capacity on our committed credit facility and demand facilities, we have approximately $10.0 billion of liquidity as at year end 2021. Our long-term Net Debt Target is between $6 billion and $8 billion. We aim for a Net Debt to Adjusted EBITDA ratio of between 1.0 to 1.5 times at the bottom of the cycle, which we see as approximately US$45 WTI per barrel.

Returns-focused Capital Allocation

The Company's capital program and current base dividend are sustainable at US$45 WTI per barrel, with the opportunity to grow shareholder returns over the life of the plan as Net Debt is further reduced. Once Cenovus achieves Net Debt below $8 billion we expect to have further expanded capacity for increasing shareholder returns, including share purchases and increasing the common share dividend.

We anticipate our total capital expenditures to be between $2.6 billion and $3.0 billion, including $200 million to $250 million (excluding insurance proceeds) for the Superior Refinery rebuild. We will continue to be disciplined with our capital. The 2022 guidance data dated December 7, 2021, is available on our website at cenovus.com.

Growing Free Funds Flow Through Pricing Cycles

Our top-tier assets and cost structures position us to grow Free Funds Flow through pricing cycles. Cenovus's diversified asset and product mix generates predictable and stable Free Funds Flow, and reduces risk and cash flow volatility through the optimization of the value chain through pipelines, logistics and marketing. We are able to generate strong margins with modest capital investment.

Cenovus has a track record of operational reliability and expects our annual upstream production to average between 780 thousand BOE per day and 820 thousand BOE per day and total downstream crude throughput of 530 thousand barrels per day to 580 thousand barrels per day in 2022. 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 production up or down accordingly. Our decisions around production levels and refinery crude run rates will be focused on maximizing the value we receive for our products.

ADVISORY

Oil and Gas Information

Barrels of Oil Equivalent – natural gas volumes have been converted to BOE on the basis of six Mcf to one bbl. BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. 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 forward-looking statements and other information (collectively "forward-looking information") about the Company's current expectations, estimates and projections, made in light of the Company's experience and perception of historical trends. Although the Company believes that the expectations represented by such forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct.

This forward-looking information is identified by words such as "anticipate", "believe", "capacity", "commit", "continue", "could", "estimate", "expect", "focus", "forecast", "future", "may", "opportunities", "option", "plan", "potential", "project", "progress', "schedule", "seek", "strive", "target", "view", and "will", or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: mitigating the impact of volatility in light-heavy crude oil differentials; capturing value from crude oil and natural gas production; optimizing margin captured across the heavy oil value chain; reducing exposure to Alberta heavy oil price differentials; maintaining exposure to global commodity prices; delivering value over the long-term; safety performance; ESG leadership; free funds flow generation; debt reduction; shareholder value and returns; reinvestment in the business and diversification; maintaining a strong balance sheet; the Company's longer-term

Net Debt target; repurchasing outstanding notes; resuming projects; integrating sustainability considerations into the Company's business decisions; achieving net zero greenhouse GHG emissions from oil sands operations by 2050; the health and safety of the Company's workforce and the public; short cycle, high return development wells; forecast capital investment; forecast production; first steam from Narrows Lake; initial production and exploration of new fields or projects; resumption or production of curtailed fields or projects; evaluating and making decisions regarding deferred projects; restarting the Superior Refinery; near-term funding; maintaining the Company's investment grade credit ratings; Net Debt to adjusted EBITDA ratio; risk reduction; maintaining capital discipline; adjusting capital and operating spending, drawing down on credit facilities or repaying existing debt, adjusting dividends paid to shareholders, repurchasing the Company's common shares for cancellation, issuing new debt, or issuing new shares; evaluating all opportunities based on a US$45 per barrel WTI price; maintaining a prudent and flexible capital structure and strong balance sheet metrics; restructuring working interests in Atlantic Canada; financial resilience; liabilities from legal proceedings; delivering value; generating strong margins; the Company's outlook for commodities and the Canadian dollar; upstream integration; mitigating the impact of crude oil and refined product prices and differentials; the Company's five key strategic objectives and five ESG focus areas; embedding environmental, economic and social considerations in business decisions; cost savings, underlying cost structure and margin enhancements; improving efficiencies; sustaining the current dividend at US$45 WTI; and ramping production up or down. Readers are cautioned not to place undue reliance on forward-looking information as the Company's 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 predicted or estimated, and can be profitably produced in the future. Readers are cautioned that the term reserves life index may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies and does not reflect the actual life of the reserves.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to the Company and others that apply to the industry generally. The factors or assumptions on which the 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; the Company's ability to realize the anticipated benefits and anticipated cost synergies of Arrangement ; the Company's ability to successfully integrate the legacy Husky business with its own and any costs associated therewith; the accuracy of any assessments undertaken in connection with the Arrangement; forecast production volumes; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; the absence of significant adverse changes to government policies, legislation and regulations (including related to climate change), Indigenous relations, interest rates, inflation, 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 the Company 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 the Company'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 the Company's share price and market capitalization over the long term; opportunities to purchase shares for cancellation at prices acceptable to the Company; the sufficiency of cash balances, internally generated cash flows, existing credit facilities, management of the Company's asset portfolio and access to capital and insurance coverage to pursue and fund future investments, sustainability and development plans and dividends, including any increase thereto; production from the Company's Conventional segment providing an economic hedge for the natural gas required as a fuel source at both the Company's oil sands and refining operations; realization of expected capacity to store within the Company's oil sands reservoirs barrels not yet produced, including that the Company 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 future 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 the Company's refining capacity, dynamic storage, existing pipeline commitments, crude-by-rail loading capacity and financial hedge transactions to partially mitigate a portion of the Company's WCS crude oil volumes against wider differentials; the Company's ability to produce from oil sands facilities on an unconstrained 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; the Company's ability to obtain necessary regulatory and partner approvals; the successful, timely and cost effective implementation of capital projects, development projects or stages thereof; the Company's ability to generate sufficient cash flow to meet current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; the Company's ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; the Company's ability to complete acquisitions and dispositions, including with desired transaction metrics and within expected timelines; the accuracy of climate scenarios and assumptions, including third party data on which the Company relies; ability to access and implement all technology and equipment necessary to achieve expected future results, including in respect of climate and GHG emissions targets and ambitions and the commercial viability and scalability of emission reduction strategies and related technology and products; continuing; collaboration with the government, Oil Sands Pathways to Net Zero and other industry organizations; expected impacts of the contingent payment to ConocoPhillips; alignment of realized WCS and WCS prices used to calculate the contingent payment to ConocoPhillips; market and business conditions; forecast inflation and other assumptions inherent in Cenovus's 2022 guidance available on cenovus.com and as set out below; the availability of Indigenous owned or operated businesses and Cenovus's ability to retain them; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2022 guidance, as updated December 7, 2021 and available on cenovus.com, assumes: Brent prices of US$74.00 per barrel, WTI prices of US$71.00 per barrel; WCS of US$55.00 per barrel; Differential WTI-WCS of US$16.00 per barrel; AECO natural gas prices of $3.70 per thousand cubic feet; Chicago 3-2-1 crack spread of US$18.00 per barrel; and an exchange rate of $0.79 US$/C$.

The risk factors and uncertainties that could cause the Company's actual results to differ materially from the forward-looking information, include, but are not limited to: the effect of the COVID-19 pandemic, including any variants thereof, on the Company's business, including any related restrictions, containment, and treatment measures taken by varying levels of government in the jurisdictions in which the Company operates; the success of the Company's new COVID-19 workplace policies and the return of people to the Company's workplace; the Company's ability to realize the anticipated benefits of the Arrangement in a timely manner or at all; the Company's ability to successfully integrate the legacy Husky business with its own in a timely and cost effective manner; unforeseen or underestimated liabilities associated with the Arrangement; risks associated with acquisitions and dispositions; the Company's ability to access or implement some or all of the technology necessary to efficiently and effectively operate its assets and achieve expected future results including in respect of climate and GHG emissions targets and ambitions and the commercial viability and scalability of emission reduction strategies and related technology and products; the development and execution of implementing strategies to meet climate and GHG emissions targets and ambitions; the effect of the Company's increased indebtedness; the effect of new significant shareholders; volatility of and other assumptions regarding commodity prices; the duration of any market downturn; foreign exchange risk, including related to agreements denominated in foreign currencies; the Company's 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; the Company's ability to achieve lower transportation costs as a result of temporarily suspending the crude-by-rail program; the Company's ability to realize the expected impacts of its capacity to store within its 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 the Company's risk management program, including the impact of derivative financial instruments, the success of the Company's hedging strategies and the sufficiency of its liquidity positions; 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 the Company's share price and market capitalization assumptions; market competition, including from alternative energy sources; risks inherent in the Company's 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 the Company's crude-by-rail terminal, including health, safety and environmental risks; the Company's ability to maintain desirable ratios of Net Debt to Adjusted EBITDA as well as Net Debt to Capitalization; the Company's ability to access various sources of debt and equity capital, generally, and on acceptable terms; the Company's ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to the Company or any of its securities; changes to the Company's dividend plans; the Company's ability to utilize tax losses in the future; the accuracy of the Company's reserves, future production and future net revenue estimates; the accuracy of the Company's accounting estimates and judgements; the Company's ability to replace and expand crude oil and natural 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 the Company's assets or goodwill from time to time; the Company's ability to maintain its relationships with its partners and to successfully manage and operate its integrated operations and business; reliability of the Company's 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 the Company's operations; potential failure of products to achieve or maintain acceptance in the market; risks associated with the energy industry's and the Company'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 the Company's business, including potential cyberattacks; geo-political and other risks associated with the Company's international operations; risks associated with climate change and the Company's assumptions relating thereto; the timing and the costs of well and pipeline construction; the Company's 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 the Company's 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 the Company operates or to any of the infrastructure upon which it relies; 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, GHG, 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 the Company's business, its financial results and 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 the Company operates or supplies; the status of the Company's relationships with the communities in which it operates, 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 the Company. In addition, there are risks that the effect of actions taken by us in implementing targets, commitments and ambitions for ESG focus areas may have a negative impact on our existing business, growth plans and future results from operations.

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 the Company's material risk factors, see Risk Management and Risk Factors in this MD&A, and to the risk factors described in other documents the Company 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 Company's website at cenovus.com.

Information on or connected to the Company's website at cenovus.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 barrels of oil equivalent	GJ	gigajoule
WTI	West Texas Intermediate	AECO	Alberta Energy Company
WCS	Western Canadian Select	NYMEX	New York Mercantile Exchange
HSB	Husky Synthetic Blend		

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.

SPECIFIED FINANCIAL MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS including Operating Margin, Operating Margin for the Upstream or Downstream segment, Operating Margin by asset, Total Integration Costs, Adjusted Funds Flow, Free Funds Flow, Net Debt, Total Debt, Net Debt to Adjusted EBITDA Ratio, Net Debt to Capitalization ratio, Net Debt Target, Long-Term Financial Liabilities, Capital Investment by Asset, Gross Margin, Refining Margin, Unit Operating Costs, Forward-looking Operating Costs per Barrel, Forward-looking Capital Investment, Forward-looking Integration Costs, Per Unit DD&A and Netbacks (including the per BOE components of netbacks and total netbacks per BOE).

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 financial measure or specified financial measure is presented in this Advisory and may also be presented in the Operating and Financial Results or Liquidity and Capital Resources sections of this MD&A.

Operating Margin

Operating Margin and Operating Margin by asset are non-GAAP financial measures used to provide a consistent measure of the cash generating performance of our operations and assets for comparability of our underlying financial performance between periods. Operating Margin is defined as revenues less purchased product, transportation and blending, operating expenses, 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.

	Upstream			Downstream			Total		
Year ended December 31, ($ millions)	**2021**	2020	2019	**2021**	2020	2019	**2021**	2020	2019
Revenues									
Gross Sales (1)	**27,844**	9,708	14,036	**26,673**	4,815	8,368	**54,517**	14,523	22,404
Less: Royalties (2)	**2,454**	371	1,173	**—**	—	—	**2,454**	371	1,173
	25,390	9,337	12,863	**26,673**	4,815	8,368	**52,063**	14,152	21,231
Expenses									
Purchased Product (1)(2)	**4,843**	1,530	2,471	**23,526**	4,429	6,735	**28,369**	5,959	9,206
Transportation and Blending (2)	**7,930**	4,764	5,234	**—**	—	—	**7,930**	4,764	5,234
Operating (2)	**3,241**	1,476	1,406	**2,258**	785	918	**5,499**	2,261	2,324
Realized (Gain) Loss on Risk Management	**788**	268	23	**104**	(21)	(16)	**892**	247	7
Operating Margin	**8,588**	1,299	3,729	**785**	(378)	731	**9,373**	921	4,460

(1) Prior period results have been adjusted for the change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Adjustments to the Consolidated Statements of Earnings (Loss) section in this MD&A.

(2) Inventory write-downs prior to January 1, 2021, have been reclassified to royalties, purchased product, transportation and blending or operating expenses to conform with the current presentation of inventory write-downs.

	2021											
	Upstream				Downstream				Total			
($ millions)	**Q4**	Q3	Q2	Q1	**Q4**	Q3	Q2	Q1	**Q4**	Q3	Q2	Q1
Revenues												
Gross Sales (1)	**8,237**	7,354	6,128	6,125	**8,135**	7,530	6,318	4,690	**16,372**	14,884	12,446	10,815
Less: Royalties	**815**	733	533	373	**—**	—	—	—	**815**	733	533	373
	7,422	6,621	5,595	5,752	**8,135**	7,530	6,318	4,690	**15,557**	14,151	11,913	10,442
Expenses												
Purchased Product (1)	**1,410**	1,270	921	1,242	**7,348**	6,708	5,502	3,968	**8,758**	7,978	6,423	5,210
Transportation and Blending	**2,387**	1,941	1,802	1,800	**—**	—	—	—	**2,387**	1,941	1,802	1,800
Operating	**865**	800	791	785	**689**	537	515	517	**1,554**	1,337	1,306	1,302
Realized (Gain) Loss on Risk Management	**202**	168	188	230	**56**	17	10	21	**258**	185	198	251
Operating Margin	**2,558**	2,442	1,893	1,695	**42**	268	291	184	**2,600**	2,710	2,184	1,879

(1) Prior period results have been adjusted for the change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Adjustments to the Consolidated Statements of Earnings (Loss) section in this MD&A.

	2020											
	Upstream				Downstream				Total			
($ millions)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenues												
Gross Sales [1]	2,749	2,746	1,566	2,647	1,124	1,252	857	1,582	3,873	3,998	2,423	4,229
Less: Royalties [2]	143	153	21	54	—	—	—	—	143	153	21	54
	2,606	2,593	1,545	2,593	1,124	1,252	857	1,582	3,730	3,845	2,402	4,175
Expenses												
Purchased Product [1] [2]	334	389	350	457	1,016	1,133	549	1,731	1,350	1,522	899	2,188
Transportation and Blending [2]	1,149	1,036	651	1,928	—	—	—	—	1,149	1,036	651	1,928
Operating [2]	389	367	316	404	192	187	186	220	581	554	502	624
Realized (Gain) Loss on Risk Management	40	137	66	25	(15)	2	(7)	(1)	25	139	59	24
Operating Margin	694	664	162	(221)	(69)	(70)	129	(368)	625	594	291	(589)

(1) Prior period results have been adjusted for the change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Adjustments to the Consolidated Statements of Earnings (Loss) section in this MD&A.

(2) Inventory write-downs prior to January 1, 2021, have been reclassified to royalties, purchased product, transportation and blending or operating expenses to conform with the current presentation of inventory write-downs.

Operating Margin by Asset

	2021		
Year ended December 31, ($ millions)	**Asia Pacific**	**Atlantic**	**Offshore [1]**
Revenues			
Gross Sales	**1,342**	**440**	**1,782**
Less: Royalties	**79**	**29**	**108**
	1,263	**411**	**1,674**
Expenses			
Transportation and Blending	**—**	**15**	**15**
Operating	**103**	**136**	**239**
Operating Margin	**1,160**	**260**	**1,420**

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

	2021											
	Asia Pacific				Atlantic				Offshore [1]			
($ millions)	**Q4**	Q3	Q2	Q1	**Q4**	Q3	Q2	Q1	**Q4**	Q3	Q2	Q1
Revenues												
Gross Sales	**377**	336	308	321	**143**	68	119	110	**520**	404	427	431
Less: Royalties	**26**	20	16	17	**8**	4	9	8	**34**	24	25	25
	351	316	292	304	**135**	64	110	102	**486**	380	402	406
Expenses												
Transportation and Blending	**—**	—	—	—	**5**	3	3	4	**5**	3	3	4
Operating	**29**	28	24	22	**44**	21	35	36	**73**	49	59	58
Operating Margin	**322**	288	268	282	**86**	40	72	62	**408**	328	340	344

(1) Found in Note 1 of the interim consolidated financial statements.

Total Integration Costs

Total Integration Costs is a non-GAAP financial measure representing costs incurred as a result of the Arrangement, excluding share issuance costs.

($ millions)	2021	2021 Q4	2021 Q3	2021 Q2	2021 Q1
Integration Costs [(1)]	**349**	**47**	45	34	223
Capitalized Integration Costs [(2)]	**53**	**4**	15	12	22
Total Integration Costs	**402**	**51**	60	46	245

(1) Per the Consolidated Statements of Earnings (Loss) and interim consolidated financial statements.
(2) Included in Capital Expenditures on the Consolidated Statements of Cash Flows.

Adjusted Funds Flow and Free Funds Flow

Adjusted Funds Flow is a non-GAAP financial 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 settlement of decommissioning liabilities and net change in non-cash working capital. Non-cash working capital is composed of accounts receivable and accrued revenues, inventories (excluding non-cash inventory write-downs and reversals), income tax receivable, accounts payable and accrued liabilities and income tax payable.

Free Funds Flow is a non-GAAP financial measure used to assist in measuring the available funds the Company has after financing its capital programs. Free Funds Flow is defined as cash from (used in) operating activities excluding settlement of decommissioning liabilities and net change in non-cash working capital minus capital investment.

Year ended December 31, ($ millions)	2021	2020	2019
Cash From (Used in) Operating Activities	**5,919**	273	3,285
(Add) Deduct:			
Settlement of Decommissioning Liabilities	**(102)**	(42)	(52)
Net Change in Non-Cash Working Capital	**(1,227)**	198	(333)
Adjusted Funds Flow [(2)]	**7,248**	117	3,670
Capital Investment	**2,563**	841	1,176
Free Funds Flow [(2)]	**4,685**	(724)	2,494

(1) Comparative figures have been restated to conform with the definition in this MD&A.

($ millions)	2021 Q4	2021 Q3	2021 Q2	2021 Q1	2020 Q4	2020 Q3	2020 Q2	2020 Q1
Cash From (Used in) Operating Activities	**2,184**	2,138	1,369	228	250	732	(834)	125
(Add) Deduct:								
Settlement of Decommissioning Liabilities	**(35)**	(38)	(18)	(11)	(6)	(3)	(2)	(31)
Net Change in Non-Cash Working Capital	**271**	(166)	(430)	(902)	(77)	328	(363)	310
Adjusted Funds Flow [(1)]	**1,948**	2,342	1,817	1,141	333	407	(469)	(154)
Capital Investment	**835**	647	534	547	242	148	147	304
Free Funds Flow [(1)]	**1,113**	1,695	1,283	594	91	259	(616)	(458)

(1) Comparative figures have been restated to conform with the definition in this MD&A.

Net Debt, Total Debt, Net Debt Target, Net Debt to Capitalization Ratio, Net Debt to Adjusted EBITDA Ratio and Net Debt to Adjusted EBITDA Ratio Target

These measures are used to steward our overall debt position and as measures of our overall financial strength.

Net Debt is a specified financial measure used to monitor our capital structure. Our forward-looking Net Debt Target is the desired amount of Net Debt that the Company strives to achieve and maintain. Net Debt is defined as Total Debt net of cash and cash equivalents and short-term investments. Total Debt is defined as short-term borrowings plus the current and long-term portions of long-term debt.

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, exploration expense, goodwill impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), revaluation gain, re-measurement of contingent payment, gains (losses) on divestiture of assets, other income (loss), net and share of income (loss) from equity-accounted investees calculated on a trailing 12-month basis.

Our forward-looking Net Debt to Adjusted EBITDA Ratio Target is the desired Net Debt to Adjusted EBITDA Ratio that the Company strives to achieve and maintain.

As at ($ millions)	**December 31, 2021**	January 1, 2021 (1)	December 31, 2020	December 31, 2019
Short-Term Borrowings	**79**	161	121	—
Current Portion of Long-Term Debt	**—**	—	—	—
Long-Term Debt	**12,385**	14,043	7,441	6,699
Total Debt	**12,464**	14,204	7,562	6,699
Less: Cash and Cash Equivalents	**(2,873)**	(1,113)	(378)	(186)
Net Debt	**9,591**	13,091	7,184	6,513
Shareholders' Equity	**23,596**		16,707	19,201
Capitalization	**33,187**		23,891	25,714
Net Debt to Capitalization Ratio (percent)	**29**		30	25
Adjusted EBITDA	**8,086**		606	4,143
Net Debt to Adjusted EBITDA Ratio (times)	**1.2**		11.9	1.6

(1) Includes balances at December 31, 2020, plus the fair value of amounts assumed from the Arrangement. The fair value of amounts assumed from the Arrangement are short-term borrowings of $40 million, long-term debt of $6.6 billion, and cash and cash equivalents of $735 million.

	2021				2020			
As at ($ millions)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Short-Term Borrowings	**79**	48	65	266	121	137	299	602
Current Portion of Long-Term Debt	**—**	545	632	—	—	—	—	—
Long-Term Debt	**12,385**	12,441	12,748	13,947	7,441	7,797	8,085	6,979
Total Debt	**12,464**	13,034	13,445	14,213	7,562	7,934	8,384	7,581
Less: Cash and Cash Equivalents	**(2,873)**	(2,010)	(1,055)	(873)	(378)	(404)	(152)	(160)
Net Debt	**9,591**	11,024	12,390	13,340	7,184	7,530	8,232	7,421
Shareholders' Equity	**23,596**	24,373	23,629	23,618	16,707	17,032	17,311	17,734
Capitalization	**33,187**	35,397	36,019	36,958	23,891	24,562	25,543	25,155
Net Debt to Capitalization Ratio (percent)	**29**	31	34	36	30	31	32	30
Adjusted EBITDA	**8,086**	6,327	4,369	2,584	606	900	1,360	2,386
Net Debt to Adjusted EBITDA Ratio (times)	**1.2**	1.7	2.8	5.2	11.9	8.4	6.1	3.1

Total Long-Term Liabilities

Total Long-Term Liabilities is a non-GAAP financial measure. The measure is disclosed to fulfill the requirements of National Instrument 51-102, "*Continuous Disclosure Obligations*" and is defined as total liabilities less total current liabilities.

As at December 31, ($ millions)	**2021**	2020	2019
Long-Term Debt	**12,385**	7,441	6,699
Lease Liabilities	**2,685**	1,573	1,720
Contingent Payment	**—**	27	64
Decommissioning Liabilities	**3,906**	1,248	1,235
Other Liabilities	**929**	181	241
Deferred Income Taxes	**3,286**	3,234	4,032
Total Long-Term Liabilities	**23,191**	13,704	13,991

Capital Investment by Asset and Forward-Looking Capital Investment

Capital Investment by asset is a specified financial measure that represents historical capital expenditures for the assets identified. Forward-looking capital investment is a specified financial measure representing anticipated future capital expenditures.

Gross Margin, Refining Margin and Unit Operating Expense

Gross Margin, Refining Margin and Unit Operating Expense are specified financial measures used to evaluate performance of our downstream operations. We define Gross Margin as revenues less purchased product. We define Refining Margin as Gross Margin divided by barrels of crude throughput. We define Unit Operating Expense as operating expenses divided by barrels of crude throughput.

Canadian Manufacturing

	2021			
Year ended December 31, ($ millions)	**Lloydminster Upgrader**	**Lloydminster Refinery**	**Other [1]**	**Per Consolidated Financial Statements**
Revenues	**2,559**	**817**	**1,096**	**4,472**
Purchased Product	**2,041**	**659**	**852**	**3,552**
Gross Margin	**518**	**158**	**244**	**920**

	Operating Statistics			
	Lloydminster Upgrader	**Lloydminster Refinery**		**Consolidated**
Crude Throughput (Mbbls/d)	**79.0**	**27.5**		**106.5**
Refining Margin ($/bbl)	**17.99**	**15.64**		**23.64**

(1) Includes ethanol and crude-by-rail operations, and marketing activities.

	2021															
	Lloydminster Upgrader				**Lloydminster Refinery**				**Other [1]**				**Per Consolidated Interim Financial Statements**			
($ millions)	**Q4**	Q3	Q2	Q1	**Q4**	Q3	Q2	Q1	**Q4**	Q3	Q2	Q1	**Q4**	Q3	Q2	Q1
Revenues	**748**	684	601	526	**206**	278	197	136	**409**	253	290	144	**1,363**	1,215	1,088	806
Purchased Product	**592**	556	484	409	**172**	230	152	105	**364**	200	171	117	**1,128**	986	807	631
Gross Margin	**156**	128	117	117	**34**	48	45	31	**45**	53	119	27	**235**	229	281	175

	Operating Statistics											
	Lloydminster Upgrader				**Lloydminster Refinery**				**Consolidated**			
	Q4	Q3	Q2	Q1	**Q4**	Q3	Q2	Q1	**Q4**	Q3	Q2	Q1
Crude Throughput (Mbbls/d)	**80.4**	81.2	76.1	78.4	**27.9**	27.1	27.4	27.8	**108.3**	108.3	103.5	106.2
Refining Margin ($/bbl)	**21.05**	16.93	16.90	16.64	**13.25**	19.29	18.03	12.43	**23.60**	22.89	29.78	18.40

(1) Includes ethanol and crude-by-rail operations, and marketing activities.

U.S. Manufacturing

Year ended December 31, ($ millions)	**2021**	2020 [1]	2019 [1]
Revenues [2]	**20,043**	4,733	8,291
Purchased Product [2]	**17,955**	4,429	6,735
Gross Margin	**2,088**	304	1,556
Crude Throughput (Mbbls/d)	**401.5**	185.9	221.3
Refining Margin ($/bbl)	**14.25**	4.47	19.26

(1) Prior periods have been reclassified to conform with current period's operating segments.
(2) Found in Note 1 of the Consolidated Financial Statements.

($ millions)	2021 Q4	2021 Q3	2021 Q2	2021 Q1	2020 [1] Q4	2020 [1] Q3	2020 [1] Q2	2020 [1] Q1
Revenues [2]	**6,154**	5,723	4,729	3,437	1,100	1,237	841	1,555
Purchased Product [2]	**5,635**	5,171	4,229	2,920	1,016	1,133	549	1,731
Gross Margin	**519**	552	500	517	84	104	292	(176)
Crude Throughput (Mbbls/d)	**361.6**	445.8	435.5	362.9	169.0	191.1	162.3	221.1
Refining Margin ($/bbl)	**15.63**	13.45	12.59	15.84	5.40	5.91	19.77	(8.75)

(1) Prior periods have been reclassified to conform with current period's operating segments.
(2) Found in Note 1 of the interim consolidated financial statements.

Retail [1]

($ millions)	Three Months Ended December 31, 2021	Year Ended December 31, 2021
Revenues	**618**	**2,158**
Purchased Product	**585**	**2,019**
Gross Margin	**33**	**139**

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

Per Unit DD&A

Per Unit DD&A is a specified financial measure used to measure DD&A on a per-unit of production basis. We define Per Unit DD&A as DD&A divided by production.

Year Ended December 31, 2021 ($ millions)	Per Consolidated Financial Statements [1]	(Impairments) Reversals	Equity Adjustment [2]	Other	Basis of DD&A per BOE calculation
Oil Sands	**2,666**	**—**	**—**	**(263)**	**2,403**
Conventional	**3**	**378**	**—**	**63**	**444**
Offshore	**492**	**—**	**70**	**134**	**696**

Year Ended December 31, 2020 ($ millions)	Per Consolidated Financial Statements [1]	(Impairments) Reversals	Other	Basis of DD&A per BOE calculation
Oil Sands	**1,687**	**—**	**(238)**	**1,449**
Conventional	**880**	**(555)**	**(2)**	**323**

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.

Netback Reconciliations

Netback is a non-GAAP financial 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. 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 crude oil to transport it to market.

The following tables provide a reconciliation of the items comprising Netbacks to Operating Margin found in our Consolidated Financial Statements. Netback reconciliations for the first, second and third quarters of 2021 can be found in the respective quarters' MD&A, with the exception of Upstream and Oil Sands results which have been represented below.

Total Production

Upstream Financial Results

	Per Consolidated Financial Statements	Adjustments					Basis of Netback Calculation
Year Ended December 31, 2021 ($ millions)	Total Upstream (1)	Condensate	Third-party Sourced	Internal Consumption (2)	Equity Adjustment (3)	Other (4)	Total Upstream
Gross Sales	**27,844**	(6,311)	(4,545)	(710)	224	(390)	**16,112**
Royalties	**2,454**	—	—	—	52	—	**2,506**
Purchased Product	**4,843**	—	(4,545)	—	—	(298)	**—**
Transportation and Blending	**7,930**	(6,311)	—	—	—	—	**1,619**
Operating	**3,241**	—	(8)	(710)	25	(36)	**2,512**
Netback	**9,376**	—	8	—	147	(56)	**9,475**
Realized (Gain) Loss on Risk Management	**788**	**—**	**(2)**	**—**	**—**	**—**	**786**
Operating Margin	**8,588**	**—**	**10**	**—**	**147**	**(56)**	**8,689**

	Per Consolidated Financial Statements	Adjustments					Basis of Netback Calculation
Year Ended December 31, 2020 ($ millions) (6)	Total Upstream (1)	Condensate	Third-party Sourced (5)	Inventory Write-Down (7)	Internal Consumption (2)	Other (4)	Total Upstream
Gross Sales (5)	9,708	(3,452)	(1,559)	—	(295)	(58)	4,344
Royalties	371	—	—	(1)	—	—	370
Purchased Product (5)	1,530	—	(1,559)	—	—	29	—
Transportation and Blending	4,764	(3,452)	—	1	—	—	1,313
Operating	1,476	—	—	—	(295)	(72)	1,109
Netback	1,567	—	—	—	—	(15)	1,552
Realized (Gain) Loss on Risk Management	268	—	—	—	—	—	268
Operating Margin	1,299	—	—	—	—	(15)	1,284

	Per Consolidated Financial Statements					Basis of Netback Calculation
Year Ended December 31, 2019 ($ millions) (6)	Total Upstream (1)	Condensate	Third-party Sourced (5)	Internal Consumption (2)	Other (4)	Total Upstream
Gross Sales (5)	14,036	(4,021)	(2,507)	(222)	(64)	7,222
Royalties	1,173	—	—	—	(7)	1,166
Purchased Product (5)	2,471	—	(2,507)	—	36	—
Transportation and Blending	5,234	(4,021)	—	—	1	1,214
Operating	1,406	—	—	(222)	(63)	1,121
Netback	3,752	—	—	—	(31)	3,721
Realized (Gain) Loss on Risk Management	23	—	—	—	—	23
Operating Margin	3,729	—	—	—	(31)	3,698

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Represents natural gas volumes produced by the Conventional segment used for internal consumption by the Oil Sands segment.
(3) Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.
(4) Other includes construction, transportation and blending and third-party processing margin.
(5) Prior period results have been adjusted for the change in presentation of product swaps and certain third-party purchases used in blending and optimization activities.See the Adjustments to the Consolidated Statements of Earnings (Loss) section in this MD&A.
(6) Prior periods have been reclassified to conform with current period's operating segments.
(7) Netbacks do not reflect non-cash write-downs or reversals of product inventory until it is realized when the product is sold. These amounts are net of inventory write-down reversals.

Three Months Ended December 31, 2021 ($ millions)	Per Interim Consolidated Financial Statements Total Upstream [1]	Adjustments Condensate	Third-Party Sourced	Internal Consumption [2]	Equity Adjustment [3]	Other [4][7]	Basis of Netback Calculation Total Upstream
Gross Sales	**8,237**	(1,989)	(1,291)	(241)	62	(146)	**4,632**
Royalties	**815**	—	—	—	29	—	**844**
Purchased Product	**1,410**	—	(1,291)	—	—	(119)	**—**
Transportation and Blending	**2,387**	(1,989)	—	—	—	—	**398**
Operating	**865**	—	(8)	(241)	7	(3)	**620**
Netback	**2,760**	**—**	**8**	**—**	**26**	**(24)**	**2,770**
Realized (Gain) Loss on Risk Management	**202**	**—**	**—**	**—**	**—**	**—**	**202**
Operating Margin	**2,558**	**—**	**8**	**—**	**26**	**(24)**	**2,568**

Three Months Ended December 31, 2020 ($ millions) [5]	Per Interim Consolidated Financial Statements Total Upstream [1]	Adjustments Condensate	Third-party Sourced	Internal Consumption [2]	Other [4]	Basis of Netback Calculation Total Upstream
Gross Sales [8]	2,749	(853)	(339)	(92)	(16)	1,449
Royalties	143	—	—	—	—	143
Purchased Product [8]	334	—	(339)	—	5	—
Transportation and Blending	1,149	(853)	—	—	—	296
Operating	389	—	—	(92)	(18)	279
Netback	734	—	—	—	(3)	731
Realized (Gain) Loss on Risk Management	40	—	—	—	—	40
Operating Margin	694	—	—	—	(3)	691

(1) *Found in Note 1 of the Consolidated Financial Statements.*
(2) *Represents natural gas volumes produced by the Conventional segment used for internal consumption by the Oil Sands segment.*
(3) *Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.*
(4) *Other includes construction, transportation and blending and third-party processing margin.*
(5) *Prior periods have been reclassified to conform with current period's operating segments.*
(6) *Realization of prior period inventory write-down reversals.*
(7) *Sunrise gross sales, transportation and blending and operating costs have been represented to reflect a change in classification of marketing activities for the third quarter of 2021.*
(8) *Prior period results have been adjusted for the change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Adjustments to the Consolidated Statements of Earnings (Loss) section in this MD&A.*

Oil Sands

Year Ended December 31, 2021 ($ millions)	Basis of Netback Calculation Foster Creek	Christina Lake	Sunrise	Other Oil Sands [2]	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
Gross Sales	**4,341**	**5,115**	**616**	**3,212**	**13,284**	**13**	**13,297**
Royalties	**767**	**1,078**	**20**	**330**	**2,195**	**1**	**2,196**
Purchased Product	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Transportation and Blending	**686**	**526**	**111**	**207**	**1,530**	**—**	**1,530**
Operating	**701**	**700**	**157**	**858**	**2,416**	**21**	**2,437**
Netback	**2,187**	**2,811**	**328**	**1,817**	**7,143**	**(9)**	**7,134**
Realized (Gain) Loss on Risk Management							**786**
Operating Margin							**6,348**

Year Ended December 31, 2021 ($ millions)	Basis of Netback Calculation Total Oil Sands	Adjustments Condensate	Third-party Sourced	Other [3]	Per Consolidated Financial Statements [1] Total Oil Sands
Gross Sales	**13,297**	**6,311**	**2,890**	**329**	**22,827**
Royalties	**2,196**	**—**	**—**	**—**	**2,196**
Purchased Product	**—**	**—**	**2,890**	**298**	**3,188**
Transportation and Blending	**1,530**	**6,311**	**—**		**7,841**
Operating	**2,437**	**—**	**—**	**14**	**2,451**
Netback	**7,134**	**—**	**—**	**17**	**7,151**
Realized (Gain) Loss on Risk Management	**786**	**—**	**—**	**—**	**786**
Operating Margin	**6,348**	**—**	**—**	**17**	**6,365**

(1) *Found in Note 1 of the Consolidated Financial Statements.*
(2) *Includes Tucker, Lloydminster thermal and Lloydminster conventional heavy oil assets.*
(3) *Other includes construction, transportation and blending margin.*

Year Ended December 31, 2020 ($ millions)	Basis of Netback Calculation Foster Creek	Christina Lake	Total Oil Sands
Gross Sales	1,859	2,194	4,053
Royalties	95	235	330
Purchased Product	—	—	—
Transportation and Blending	667	565	1,232
Operating	558	551	1,109
Netback	539	843	1,382
Realized (Gain) Loss on Risk Management			268
Operating Margin			1,114

	Basis of Netback Calculation	Adjustments				Per Consolidated Financial Statements (1)
Year Ended December 31, 2020 ($ millions) (3)	Total Oil Sands	Condensate	Third-party Sourced	Inventory Write-down (5)	Other	Total Oil Sands
Gross Sales (6)	4,053	3,452	1,290	—	9	8,804
Royalties	330	—	—	1	—	331
Purchased Product (6)	—	—	1,290	—	(28)	1,262
Transportation and Blending	1,232	3,452	—	(1)	—	4,683
Operating	1,109	—	—	—	47	1,156
Netback	1,382	—	—	—	(10)	1,372
Realized (Gain) Loss on Risk Management	268	—	—	—	—	268
Operating Margin	1,114	—	—	—	(10)	1,104

Year Ended December 31, 2019 ($ millions)	Basis of Netback Calculation Foster Creek	Christina Lake	Total Oil Sands
Gross Sales	3,295	3,511	6,806
Royalties	486	650	1,136
Purchased Product	—	—	—
Transportation and Blending	674	458	1,132
Operating	526	505	1,031
Netback	1,609	1,898	3,507
Realized (Gain) Loss on Risk Management			23
Operating Margin			3,484

	Basis of Netback Calculation	Adjustments			Per Consolidated Financial Statements (1)
Year Ended December 31, 2019 ($ millions)	Total Oil Sands	Condensate	Third-party Sourced	Other (3)	Total Oil Sands
Gross Sales (6)	6,806	4,021	2,263	11	13,101
Royalties	1,136	—	—	7	1,143
Purchased Product (6)	—	—	2,263	(32)	2,231
Transportation and Blending	1,132	4,021	—	(1)	5,152
Operating	1,031	—	—	36	1,067
Netback	3,507	—	—	1	3,508
Realized (Gain) Loss on Risk Management	23	—	—	—	23
Operating Margin	3,484	—	—	1	3,485

(1) *Found in Note 1 of the Consolidated Financial Statements.*
(2) *Includes Tucker, Lloydminster thermal and Lloydminster conventional heavy oil assets.*
(3) *Other includes construction, transportation and blending margin.*
(4) *Prior periods have been reclassified to conform with current period's operating segments.*
(5) *Netbacks do not reflect non-cash write-downs or reversals of product inventory until it is realized when the product is sold. These amounts are net of inventory write-down reversals.*
(6) *Prior period results have been adjusted for the change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Adjustments to the Consolidated Statements of Earnings (Loss) section in this MD&A.*

Three Months Ended December 31, 2021 ($ millions)	Basis of Netback Calculation						
	Foster Creek	Christina Lake	Sunrise[6]	Other Oil Sands [2]	Total Bitumen and Heavy Oil	Natural Gas	Total Oil sands
Gross Sales	1,304	1,441	189	903	3,837	4	3,841
Royalties	280	345	7	102	734	—	734
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	166	140	28	42	376	—	376
Operating	184	194	39	230	647	6	653
Netback	674	762	115	529	2,080	(2)	2,078
Realized (Gain) Loss on Risk Management							202
Operating Margin							1,876

Three Months Ended December 31, 2021 ($ millions)	Basis of Netback Calculation	Adjustments			Per Consolidated Financial Statements [1]
	Total Oil Sands	Condensate	Third-party Sourced	Other [3][6]	Total Oil Sands
Gross Sales	3,841	1,989	749	138	6,717
Royalties	734	—	—	—	734
Purchased Product	—	—	749	119	868
Transportation and Blending	376	1,989	—	—	2,365
Operating	653	—	—	5	658
Netback	2,078	—	—	14	2,092
Realized (Gain) Loss on Risk Management	202	—	—	—	202
Operating Margin	1,876	—	—	14	1,890

Three Months Ended December 31, 2020 ($ millions)	Basis of Netback Calculation			
	Foster Creek	Christina Lake	Total Bitumen and Heavy Oil	Total Oil Sands
Gross Sales	615	756	1,371	1,371
Royalties	28	103	131	131
Purchased Product	—	—	—	—
Transportation and Blending	144	134	278	278
Operating	154	152	306	306
Netback	289	367	656	656
Realized (Gain) Loss on Risk Management				40
Operating Margin				616

Three Months Ended December 31, 2020 ($ millions) [4]	Basis of Netback Calculation	Adjustments			Per Consolidated Financial Statements [1]
	Total Oil Sands	Condensate	Third-party Sourced	Other	Total Oil Sands
Gross Sales [7]	1,371	853	256	1	2,481
Royalties	131	—	—	—	131
Purchased Product [7]	—	—	256	(6)	250
Transportation and Blending	278	853	—	—	1,131
Operating	306	—	—	11	317
Netback	656	—	—	(4)	652
Realized (Gain) Loss on Risk Management	40	—	—	—	40
Operating Margin	616	—	—	(4)	612

(1) *Found in Note 1 of the Consolidated Financial Statements.*
(2) *Includes Tucker, Lloydminster thermal and Lloydminster conventional heavy oil assets.*
(3) *Other includes construction, transportation and blending margin.*
(4) *Prior periods have been reclassified to conform with current period's operating segments.*
(5) *Netbacks do not reflect non-cash write-downs or reversals of product inventory until it is realized when the product is sold. These amounts are net of inventory write-down reversals.*
(6) *Sunrise gross sales, transportation and blending and operating expenses have been re-presented to reflect a change in classification of marketing activities for the third quarter of 2021.*
(7) *Prior period results have been adjusted for the change in presentation of product swaps and certain third-party purchases used in blending and optimization activities. See the Adjustments to the Consolidated Statements of Earnings (Loss) section in this MD&A.*

Conventional

	Basis of Netback Calculation	Adjustments		Per Consolidated Financial Statements [1]
Year Ended December 31, 2021 ($ millions)	**Conventional**	**Third-party Sourced**	**Other [2]**	**Conventional**
Gross Sales	1,519	1,655	61	3,235
Royalties	150	—	—	150
Purchased Product	—	1,655	—	1,655
Transportation and Blending	74	—	—	74
Operating	521	8	22	551
Netback	774	(8)	39	805
Realized (Gain) Loss on Risk Management	—	2	—	2
Operating Margin	774	(10)	39	803

	Basis of Netback Calculation	Adjustments		Per Consolidated Financial Statements [1]
Year Ended December 31, 2020 ($ millions) [3]	Conventional	Third-party Sourced	Other [2]	Conventional
Gross Sales	586	269	49	904
Royalties	40	—	—	40
Purchased Product	—	269	(1)	268
Transportation and Blending	81	—		81
Operating	295	—	25	320
Netback	170	—	25	195
Realized (Gain) Loss on Risk Management	—	—	—	—
Operating Margin	170	—	25	195

	Basis of Netback Calculation	Adjustments		Per Consolidated Financial Statements [1]
Year Ended December 31, 2019 ($ millions) [3]	Conventional	Third-party Sourced	Other [2]	Conventional
Gross Sales	638	244	53	935
Royalties	30	—	—	30
Purchased Product	—	244	(4)	240
Transportation and Blending	82	—		82
Operating	312	—	27	339
Netback	214	—	30	244
Realized (Gain) Loss on Risk Management	—	—	—	—
Operating Margin	214	—	30	244

	Basis of Netback Calculation	Adjustments		Per Consolidated Financial Statements [1]
Three Months Ended December 31, 2021 ($ millions)	**Conventional**	**Third-party Sourced**	**Other [2]**	**Conventional**
Gross Sales	450	542	8	1,000
Royalties	47	—	—	47
Purchased Product	—	542	—	542
Transportation and Blending	17	—	—	17
Operating	128	8	(2)	134
Netback	258	(8)	10	260
Realized (Gain) Loss on Risk Management	—	—	—	—
Operating Margin	258	(8)	10	260

	Basis of Netback Calculation	Adjustments		Per Consolidated Financial Statements [1]
Three Months Ended December 31, 2020 ($ millions) [3]	Conventional	Third-party Sourced	Other [2]	Conventional
Gross Sales	170	83	15	268
Royalties	12	—	—	12
Purchased Product	—	83	1	84
Transportation and Blending	18	—	—	18
Operating	65	—	7	72
Netback	75	—	7	82
Realized (Gain) Loss on Risk Management	—	—	—	—
Operating Margin	75	—	7	82

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Reflects operating margin from processing facility.
(3) Prior periods have been reclassified to conform with current period's operating segments.

Offshore

Year Ended December 31,2021 ($ millions)	Basis of Netback Calculation: China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Adjustment: Equity Adjustment [1]	Per Consolidated Financial Statements [2]: Total Offshore
Gross Sales	**1,342**	**224**	**1,566**	**440**	**2,006**	**(224)**	**1,782**
Royalties	**79**	**52**	**131**	**29**	**160**	**(52)**	**108**
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	**15**	**15**	—	**15**
Operating	**94**	**33**	**127**	**137**	**264**	**(25)**	**239**
Netback	**1,169**	**139**	**1,308**	**259**	**1,567**	**(147)**	**1,420**
Realized (Gain) Loss on Risk Management					—	—	—
Operating Margin					**1,567**	**(147)**	**1,420**

Three Months Ended December 31, 2021 ($ millions)	Basis of Netback Calculation: China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Adjustment: Equity Adjustment [1]	Per Consolidated Financial Statements [2]: Total Offshore
Gross Sales	**377**	**62**	**439**	**143**	**582**	**(62)**	**520**
Royalties	**26**	**29**	**55**	**8**	**63**	**(29)**	**34**
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	**5**	**5**	—	**5**
Operating	**23**	**12**	**35**	**45**	**80**	**(7)**	**73**
Netback	**328**	**21**	**349**	**85**	**434**	**(26)**	**408**
Realized (Gain) Loss on Risk Management					—	—	—
Operating Margin					**434**	**(26)**	**408**

(1) Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.
(2) Found in Note 1 of the Consolidated Financial Statements.

Sales Volumes [1]

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

(MBOE/d, unless otherwise stated)	Three Months Ended December 31, 2021	2020	Year Ended December 31, 2021	2020	2019
Oil Sands					
Foster Creek	**194.5**	161.1	**178.8**	164.9	157.8
Christina Lake	**239.1**	220.7	**232.7**	221.7	188.9
Sunrise	**29.9**	—	**25.2**	—	—
Other Oil Sands	**141.2**	—	**143.2**	—	—
Total Oil Sands	**604.7**	381.8	**579.9**	386.6	346.7
Conventional	**125.3**	86.1	**133.4**	89.8	97.4
Sales before Internal Consumption	**730.0**	467.9	**713.3**	476.4	444.1
Less: Internal Consumption [2]	**(88.8)**	(57.0)	**(86.0)**	(55.9)	(53.3)
Sales after Internal Consumption	**641.2**	410.9	**627.3**	420.5	390.8
Offshore					
Asia Pacific - China	**52.7**	—	**50.8**	—	—
Asia Pacific - Indonesia	**9.8**	—	**9.5**	—	—
Asia Pacific - Total	**62.5**	—	**60.3**	—	—
Atlantic	**15.0**	—	**13.2**	—	—
Total Offshore	**77.5**	—	**73.5**	—	—
Total Sales	**718.7**	410.9	**700.8**	420.5	390.8

(1) Presented on dry bitumen basis.
(2) Less natural gas volumes used for internal consumption by the Oil Sands segment.

The following tables have been represented for the first, second and third quarters of 2021 for a change in the presentation of product swaps and certain third-party purchases used in blending and optimization activities, and the classification of marketing activities at Sunrise. Sunrise sales volumes, gross sales, royalties, transportation and blending, and operating expenses have been represented to reflect a change in the classification of marketing activities for the first, second and third quarters of 2021. See Adjustments to the Consolidated Statements of Earnings (Loss) below for additional details about the changes in product swaps and third-party purchases.

Upstream Financial Results

	Per Interim Consolidated Financial Statements	**Adjustments**					**Basis of Netback Calculation**
Three Months Ended September 30, 2021 ($ millions)	**Total Upstream [1]**	**Condensate**	**Third-Party Sourced**	**Internal Consumption [2]**	**Equity Adjustment [3]**	**Other [4]**	**Total Upstream**
Gross Sales	**7,354**	(1,538)	(1,203)	(175)	60	(49)	**4,449**
Royalties	**733**	—	—	—	11	—	**744**
Purchased Product	**1,270**	—	(1,203)	—	—	(67)	**—**
Transportation and Blending	**1,941**	(1,538)	—	—	—	20	**423**
Operating	**800**	—	—	(175)	6	(11)	**620**
Netback	**2,610**	**—**	**—**	**—**	**43**	**9**	**2,662**
Realized (Gain) Loss on Risk Management	**168**	—	(2)	—	—	—	**166**
Operating Margin	**2,442**	**—**	**2**	**—**	**43**	**9**	**2,496**

	Per Interim Consolidated Financial Statements	**Adjustments**					**Basis of Netback Calculation**
Three Months Ended June 30, 2021 ($ millions)	**Total Upstream [1]**	**Condensate**	**Third-Party Sourced**	**Internal Consumption [2]**	**Equity Adjustment [3]**	**Other [4]**	**Total Upstream**
Gross Sales	**6,128**	(1,416)	(855)	(145)	50	(105)	**3,657**
Royalties	**533**	—	—	—	5	—	**538**
Purchased Product	**921**	—	(855)	—	—	(66)	**—**
Transportation and Blending	**1,802**	(1,416)	—	—	—	(17)	**369**
Operating	**791**	—	—	(145)	7	(11)	**642**
Netback	**2,081**	**—**	**—**	**—**	**38**	**(11)**	**2,108**
Realized (Gain) Loss on Risk Management	**188**	—	—	—	—	—	**188**
Operating Margin	**1,893**	**—**	**—**	**—**	**38**	**(11)**	**1,920**

	Per Interim Consolidated Financial Statements	**Adjustments**					**Basis of Netback Calculation**
Three Months Ended March 31, 2021 ($ millions)	**Total Upstream [1]**	**Condensate**	**Third-Party Sourced**	**Internal Consumption [2]**	**Equity Adjustment [3]**	**Other [4]**	**Total Upstream**
Gross Sales	**6,125**	(1,368)	(1,196)	(149)	52	(90)	**3,374**
Royalties	**373**	—	—	—	7	—	**380**
Purchased Product	**1,242**	—	(1,196)	—	—	(46)	**—**
Transportation and Blending	**1,800**	(1,368)	—	—	—	(3)	**429**
Operating	**785**	—	—	(149)	5	(11)	**630**
Netback	**1,925**	**—**	**—**	**—**	**40**	**(30)**	**1,935**
Realized (Gain) Loss on Risk Management	**230**	—	—	—	—	—	**230**
Operating Margin	**1,695**	**—**	**—**	**—**	**40**	**(30)**	**1,705**

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Represents natural gas volumes produced by the Conventional segment used for internal consumption by the Oil Sands segment.
(3) Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.
(4) Other includes construction, transportation and blending and third-party processing margin.

Oil Sands

Three Months Ended September 30, 2021 ($ millions)	Foster Creek	Christina Lake	Sunrise	Other Oil Sands [(2)]	Total Bitumen and Heavy Oil	Natural Gas	Total Oil sands
	Basis of Netback Calculation						
Gross Sales	1,325	1,405	173	876	3,779	3	3,782
Royalties	238	324	8	98	668	1	669
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	192	125	33	50	400	—	400
Operating	194	171	33	212	610	5	615
Netback	701	785	99	516	2,101	(3)	2,098
Realized (Gain) Loss on Risk Management							166
Operating Margin							1,932

Three Months Ended September 30, 2021 ($ millions)	Basis of Netback Calculation	Adjustments			Per Interim Consolidated Financial Statements [(1)]
	Total Oil Sands	Condensate	Third-party Sourced	Other [(3)]	Total Oil Sands
Gross Sales	3,782	1,538	758	39	6,117
Royalties	669	—	—	—	669
Purchased Product	—	—	758	67	825
Transportation and Blending	400	1,538	—	(20)	1,918
Operating	615	—	—	1	616
Netback	2,098	—	—	(9)	2,089
Realized (Gain) Loss on Risk Management	166	—	—	—	166
Operating Margin	1,932	—	—	(9)	1,923

Three Months Ended June 30, 2021 ($ millions)	Foster Creek	Christina Lake	Sunrise	Other Oil Sands [(2)]	Total Bitumen and Heavy Oil	Natural Gas	Total Oil sands
	Basis of Netback Calculation						
Gross Sales	860	1,274	131	737	3,002	3	3,005
Royalties	142	242	2	83	469	—	469
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	155	131	26	35	347	—	347
Operating	154	171	54	205	584	5	589
Netback	409	730	49	414	1,602	(2)	1,600
Realized (Gain) Loss on Risk Management							189
Operating Margin							1,411

Three Months Ended June 30, 2021 ($ millions)	Basis of Netback Calculation	Adjustments			Per Interim Consolidated Financial Statements [(1)]
	Total Oil Sands	Condensate	Third-party Sourced	Other [(3)]	Total Oil Sands
Gross Sales	3,005	1,416	568	86	5,075
Royalties	469	—	—	—	469
Purchased Product	—	—	568	66	634
Transportation and Blending	347	1,416	—	17	1,780
Operating	589	—	—	3	592
Netback	1,600	—	—	—	1,600
Realized (Gain) Loss on Risk Management	189	—	—	—	189
Operating Margin	1,411	—	—	—	1,411

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Includes Tucker, Lloydminster thermal and Lloydminster conventional heavy oil assets.
(3) Other includes construction, transportation and blending margin.

Three Months Ended March 31, 2021 ($ millions)	Basis of Netback Calculation						
	Foster Creek	Christina Lake	Sunrise	Other Oil Sands [2]	Total Bitumen and Heavy Oil	Natural Gas	Total Oil sands
Gross Sales	852	995	123	696	2,666	3	2,669
Royalties	107	167	3	47	324	—	324
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	173	130	24	80	407	—	407
Operating	169	164	31	211	575	5	580
Netback	403	534	65	358	1,360	(2)	1,358
Realized (Gain) Loss on Risk Management							229
Operating Margin							1,129

Three Months Ended March 31, 2021 ($ millions)	Basis of Netback Calculation	Adjustments			Per Interim Consolidated Financial Statements [1]
	Total Oil Sands	Condensate	Third-party Sourced	Other [3]	Total Oil Sands
Gross Sales	2,669	1,368	815	66	4,918
Royalties	324	—	—	—	324
Purchased Product	—	—	815	46	861
Transportation and Blending	407	1,368	—	3	1,778
Operating	580	—	—	5	585
Netback	1,358	—	—	12	1,370
Realized (Gain) Loss on Risk Management	229	—	—	—	229
Operating Margin	1,129	—	—	12	1,141

(1) *Found in Note 1 of the Consolidated Financial Statements.*
(2) *Includes Tucker, Lloydminster thermal and Lloydminster conventional heavy oil assets.*
(3) *Other includes construction, transportation and blending margin.*

Adjustments to the Consolidated Statements of Earnings (Loss)

Certain comparative information presented in the Consolidated Statements of Earnings (Loss), within the Oil Sands segment, has been revised. During the three and twelve months ended December 31, 2021, the Company made adjustments to more appropriately record certain third-party purchases used for blending and optimization activities. A portion of third-party purchases and sales were previously recorded on a net basis in gross sales. It was determined that the purchases were more appropriately reported as as purchased product. These amounts have now been re-presented as purchased product to be consistent with similar transactions. In addition, the Company identified the inconsistent treatment of product swaps, which were being recorded appropriately on a net basis to either gross sales or purchased product. Going forward, all gains or losses on product swaps will be recorded to purchased product. As a result, Cenovus revised the comparative periods increasing revenues and purchased product, with no impact to net earnings (loss), segment income (loss), netbacks, cash flows or financial position.

The following table reconciles the amounts previously reported in the Consolidated Statements of Earnings (Loss) to the corresponding revised amounts:

2021 Revisions

	Three Months Ended March 31, 2021			**Three Months Ended June 30, 2021**			**Three Months Ended September 30, 2021**		
Oil Sands Segment	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**
Gross Sales	4,775	143	**4,918**	5,015	60	**5,075**	6,114	3	**6,117**
Purchased Product	718	143	**861**	574	60	**634**	822	3	**825**

2020 Revisions

	Three Months Ended March 31, 2020			**Three Months Ended June 30, 2020**			**Three Months Ended September 30, 2020**		
Oil Sands Segment	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**
Gross Sales	2,434	(9)	**2,425**	1,247	137	**1,384**	2,436	78	**2,514**
Purchased Product	405	(9)	**396**	166	137	**303**	235	78	**313**

	Three Months Ended December 31, 2020			**Twelve Months Ended December 31, 2020**		
Oil Sands Segment	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**
Gross Sales	2,364	117	**2,481**	8,481	323	**8,804**
Purchased Product	133	117	**250**	939	323	**1,262**

2019 Revisions

	Twelve Months Ended December 31, 2019		
Oil Sands Segment	Previously Reported	Revision	**Revised**
Gross Sales	12,739	362	**13,101**
Purchased Product	1,869	362	**2,231**