



MANAGEMENT'S DISCUSSION AND ANALYSIS

For the periods ended September 30, 2021

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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 November 2, 2021, should be read in conjunction with our September 30, 2021, unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2020 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2020, MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of November 2, 2021, unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus management ("Management") prepared the MD&A. The interim MD&As and the annual MD&A are reviewed by the Audit Committee and recommended for approval by the Cenovus Board of Directors ("the Board"). Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

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. In connection with its acquisition of Husky and in accordance with applicable securities laws, Cenovus filed a business acquisition report on March 26, 2021, containing the pro forma financial statements of the combined company as at December 31, 2020. Additional information concerning Husky's business and assets as at December 31, 2020 may be found in the annual information form of Husky dated February 8, 2021, for the year ended December 31, 2020, (the "Husky AIF") and Husky's management's discussion and analysis of the financial and operating results for the year ended December 31, 2020, (the "Husky MD&A"), each of which is filed and available on SEDAR under Husky's profile at sedar.com.

Basis of Presentation

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

Non-GAAP Measures and Additional Subtotals

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

OVERVIEW OF CENOVUS

We are a Canadian-based integrated energy company headquartered in Calgary, Alberta. Our common shares and warrants are listed on the Toronto ("TSX") and New York ("NYSE") stock exchanges. Our cumulative redeemable preferred shares Series 1, 2, 3, 5 and 7 are listed on the TSX. We are the third 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. 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 operations include upgrading, refining and retail operations in Canada and the U.S.

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 like transportation fuels.

During the three months ended September 30, 2021, crude oil production from our Oil Sands assets averaged 597.0 thousand barrels per day, which is generally aligned with our downstream crude oil throughput of 554.1 thousand barrels per day. Total upstream production averaged 804.8 thousand barrels of oil equivalent ("BOE") per day.

Year-to-date, crude oil production from our Oil Sands assets averaged 566.8 thousand barrels per day and downstream crude oil throughput averaged 521.0 thousand barrels per day. Total upstream production averaged 780.1 thousand 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.

Cenovus and Husky Arrangement

On January 1, 2021, Cenovus and Husky Energy Inc. ("Husky") closed the 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 common share purchase warrants of Cenovus. In addition, all of the issued and outstanding Husky preferred shares were exchanged for Cenovus preferred shares with substantially identical terms.

The Arrangement combines high quality oil sands and heavy oil assets with extensive trading, supply 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 Strategy

Our strategy remains focused on maximizing shareholder value through cost leadership and realizing the best margins for our products. Our diverse and integrated portfolio will help us to deliver stable cash flow through price cycles while maintaining safe and reliable operations. The Company has a cost-and-market-advantaged asset portfolio, and prioritizes Free Funds Flow generation, balance sheet strength and returns to shareholders. We remain focused on reducing Net Debt (as defined in this MD&A) and sustainably growing shareholder returns. We believe that maintaining a strong balance sheet will help Cenovus navigate through commodity price volatility.

Our financial framework has established an interim Net Debt target of \$10 billion and \$8 billion or lower in the longer term. This aligns with our target of a Net Debt to Adjusted EBITDA ratio of less than two times at the bottom of the cycle, which we see as approximately US\$45 per barrel West Texas Intermediate ("WTI"). We plan to use our capital allocation framework to evaluate disciplined investments in our portfolio against dividends, share repurchases and managing to the optimal debt level while maintaining investment grade status. Environmental, Social and Governance ("ESG") considerations are embedded into our framework and business plan. Our investment focus will be on areas where we believe we have the greatest competitive advantage to generate the highest returns.

On January 28, 2021, we announced our 2021 budget focused on sustaining capital and generating Free Funds Flow to strengthen the balance sheet, accelerated by capturing transaction-related synergies across the organization. 2021 guidance dated July 28, 2021, is available on our website at cenovus.com.

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 cold and enhanced oil recovery ("EOR") 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 other 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 into synthetic crude oil, diesel fuel, asphalt and other ancillary products. Cenovus seeks to maximize the value per barrel from its heavy oil 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 diesel fuel, gasoline, jet fuel, asphalt and other products at the wholly-owned Lima Refinery and Superior Refinery, the Wood River and Borger refineries (jointly owned with operator Phillips 66) and the Toledo Refinery (jointly owned with operator BP Products North America Inc. ("BP")). Cenovus also markets 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 and crude oil production used as feedstock by the Canadian Manufacturing and U.S. Manufacturing segments. Eliminations are recorded at transfer prices based on current market prices.

To conform to the presentation adopted for the current period's operating segments, the following comparatives prior to January 1, 2021, have been reclassified:

- The Company's market optimization activities, previously reported in the Refining and Marketing segment, have been reclassified to the Oil Sands and Conventional segments.
- The Bruderheim crude-by-rail terminal results, previously reported under the Refining and Marketing segment, have been reclassified to the Canadian Manufacturing segment.
- The refining activities in the U.S. with operator Phillips 66, previously reported in the Refining and Marketing segment, have been reclassified to the U.S. Manufacturing segment.
- The Company's unrealized gain and loss on risk management, previously reported in the Corporate and Eliminations segment, have been reclassified to the reportable segment to which the derivative instrument relates.

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 preliminary purchase price allocation is based on Management's best estimate of the assets acquired and liabilities assumed. The Company will finalize the value of net assets acquired by December 31, 2021, and adjustments to initial estimates, including goodwill, may be required. No significant adjustments were made to the preliminary purchase price allocation as at September 30, 2021.

QUARTERLY RESULTS OVERVIEW

During the third quarter, we continued to build on our strong operational performance from the first half of 2021, focusing on health and safety as our top priority while maintaining our low operating and capital cost structure. Our solid financial results, driven by our integrated asset base and the improving commodity price environment, helped us reduce our Net Debt by \$1.4 billion during the three months ended September 30, 2021. We have reduced our Net Debt by \$2.1 billion since the Arrangement.

Summary of Quarterly Results

	Nine Months Ended September 30,		2021			2020				2019	
(\$ millions, except where indicated)	2021	2020	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Production Volumes ⁽¹⁾ (MBOE/d)	780.1	473.3	804.8	765.9	769.3	467.2	471.8	465.4	482.6	467.4	448.5
Crude Throughput ⁽²⁾ (Mbbbls/d)	521.0	191.5	554.1	539.0	469.1	169.0	191.1	162.3	221.1	227.9	232.4
Revenues ⁽³⁾	32,425	9,794	12,698	10,577	9,150	3,426	3,659	2,174	3,961	4,838	4,736
Operating Margin ⁽⁴⁾	6,773	296	2,710	2,184	1,879	625	594	291	(589)	864	1,080
Cash From (Used in) Operating Activities	3,735	23	2,138	1,369	228	250	732	(834)	125	740	834
Adjusted Funds Flow ⁽⁵⁾	5,300	(216)	2,342	1,817	1,141	333	407	(469)	(154)	679	917
Net Earnings (Loss)	995	(2,226)	551	224	220	(153)	(194)	(235)	(1,797)	113	187
Per Share - basic (\$)	0.48	(1.81)	0.27	0.11	0.10	(0.12)	(0.16)	(0.19)	(1.46)	0.09	0.15
Per Share - diluted (\$)	0.47	(1.81)	0.27	0.11	0.10	(0.12)	(0.16)	(0.19)	(1.46)	0.09	0.15
Capital Investment ⁽⁶⁾	1,728	599	647	534	547	242	148	147	304	317	294
Net Debt ⁽⁷⁾	11,024	7,530	11,024	12,390	13,340	7,184	7,530	8,232	7,421	6,513	6,802
Cash Dividends											
Common Shares	106	77	35	36	35	—	—	—	77	77	60
Per Common Share (\$)	0.0525	0.0625	0.0175	0.0175	0.0175	—	—	—	0.0625	0.0625	0.0500
Preferred Shares	26	—	9	8	9	—	—	—	—	—	—

(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 portion of inventory write-downs reclassified to royalties.

(4) Additional subtotal found in Note 1 of the interim Consolidated Financial Statements and defined in this MD&A.

(5) Non-GAAP measure defined in this MD&A. Comparative figures have been restated to conform with the definition in this MD&A.

(6) Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets.

(7) Non-GAAP measure defined in this MD&A. Includes long-term debt and short-term borrowings assumed at fair value of \$6.6 billion as part of the Arrangement.

Crude oil prices and market crack spreads continued to improve in the third quarter compared with the second quarter and first nine months of 2020. Increased crude oil global demand amid roll out efforts of the novel coronavirus ("COVID-19") vaccines, economic recoveries, and declines in crude oil inventories drove improved commodity markets.

Operationally, variables under Management's control performed very well. Our upstream production averaged 804.8 thousand BOE per day in the third quarter, compared with 471.8 thousand BOE per day in the third quarter of 2020. Assets acquired in the Arrangement averaged approximately 295.0 thousand BOE per day during the quarter.

Our downstream crude throughput averaged 554.1 thousand barrels per day in the third quarter compared with 191.1 thousand barrels per day in the third quarter of 2020. Assets acquired in the Arrangement averaged 342.4 thousand barrels per day of crude throughput during the quarter.

In the third quarter we incurred \$60 million of integration expenditures, including capital of \$15 million. Year-to-date integration expenditures, including capital, are approximately \$351 million of the \$400 million to \$450 million expected in 2021 as integration work continues throughout the year.

In the third quarter we:

- Generated cash from operating activities of \$2.1 billion. Adjusted funds flow was \$2.3 billion and capital investment was \$647 million, resulting in Free Funds Flow of \$1.7 billion.
- Generated Operating Margin of \$2.7 billion compared with \$594 million in the third quarter of 2020, primarily due to higher average realized crude oil, NGLs and natural gas sales prices, higher market crack spreads, increased sales volumes from assets acquired in the Arrangement, and increased production at Foster Creek and Christina Lake.
- Reduced our Net Debt by \$1.4 billion.
- Achieved record single-day production at Foster Creek and Christina Lake.

During the quarter we entered into an agreement to sell 50 million shares of Headwater Exploration Inc. ("Headwater") for gross proceeds of \$228 million. The transaction closed in October.

In addition, during the third quarter, we closed \$82 million out of approximately \$110 million in combined gross proceeds of previously announced asset sales within the Conventional segment located in the East Clearwater and Kaybob areas. The remainder of the asset sales closed in October.

In the third quarter, we restructured our interests in the Atlantic region. 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 will proceed, extending the life of the field to 2033. Production, which has been suspended since 2019, is expected to resume before the end of 2022. In addition, we entered into an agreement with our partners in the White Rose field to decrease our working interest contingent on the approval of restarting the West White Rose project.

In September we issued US\$1.25 billion of 10-year and 30-year notes and used the proceeds and cash on hand to repurchase approximately US\$1.7 billion in principal of our outstanding notes. We redeemed an additional US\$425 million in principal of our outstanding notes in October. These transactions reduced our total debt by approximately US\$900 million, will generate substantial interest expense savings going forward and extend the maturity profile of our existing debt. This set of transactions, along with our updated bank lines of credit, help reduce financing risk in the near-term.

Since the Arrangement, we have reduced our Net Debt by \$2.1 billion to \$11.0 billion on September 30, 2021. As we approach our Net Debt target of \$10.0 billion, we are positioned to increase our allocation of Free Funds Flow towards shareholder returns.

On November 2, 2021, the Company's Board of Directors approved filing an application with the TSX for the implementation of a normal course issuer bid ("NCIB") to purchase up to 146.5 million of the Company's common shares.

On November 2, 2021, the Company's Board of Directors declared a fourth quarter dividend of \$0.035 per common share, payable on December 31, 2021, to common shareholders of record as at December 15, 2021. This is an increase of \$0.0175 per common share compared with our dividends declared and paid in the third quarter of 2021.

We expect our total capital expenditures to be between \$2.3 billion and \$2.7 billion in 2021, including \$520 million to \$570 million (excluding insurance proceeds) for the Superior Refinery rebuild. We will continue to be disciplined with our capital. Our guidance dated July 28, 2021 is available on our website at cenovus.com.

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 for the quarter 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

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2021	Percent Change	2020	2021	Percent Change	2020
Upstream Production Volumes by Segment						
Oil Sands (Mbbbls/d)						
Foster Creek	187.1	13	165.0	169.1	3	164.9
Christina Lake	242.5	10	221.0	232.0	7	217.1
Sunrise ⁽¹⁾	28.3	—	—	26.1	—	—
Lloydminster Thermal	98.0	—	—	97.3	—	—
Tucker	20.6	—	—	21.7	—	—
Lloydminster Cold/EOR	20.5	—	—	20.6	—	—
Total Oil Sands Crude Oil ⁽²⁾	597.0	55	386.0	566.8	48	382.0
Oil Sands Natural Gas ⁽³⁾ (MMcf/d)	11.9	—	—	12.7	—	—
Conventional ⁽⁴⁾ (MBOE/d)	132.0	54	85.9	136.4	50	91.2
Offshore (MBOE/d)						
Asia Pacific ^{(5) (6)}	59.8	—	—	59.5	—	—
Atlantic ⁽⁷⁾	13.9	—	—	15.3	—	—
Offshore Total	73.7	—	—	74.8	—	—
Total Production Volumes (MBOE/d)	804.8	71	471.8	780.1	65	473.3
Upstream Production Volumes by Product						
Bitumen (Mbbbls/d)	576.5	49	386.0	546.2	43	382.0
Heavy Crude Oil (Mbbbls/d)	19.3	—	—	19.4	—	—
Light and Medium Crude Oil (Mbbbls/d)	23.8	217	7.5	25.3	233	7.6
NGLs (Mbbbls/d)	35.5	94	18.3	39.3	97	19.9
Conventional Natural Gas (MMcf/d)	897.9	149	360.1	899.5	135	382.3
Total Production Volumes (MBOE/d)	804.8	71	471.8	780.1	65	473.3
Total Upstream Sales Volumes ⁽⁸⁾ (MBOE/d)	728.1	70	428.7	694.5	64	423.7
Downstream Manufacturing Crude Throughput						
Canadian Manufacturing (Mbbbls/d)						
Lloydminster Upgrader	81.2	—	—	78.6	—	—
Lloydminster Refinery	27.1	—	—	27.4	—	—
Canadian Manufacturing Total	108.3	—	—	106.0	—	—
U.S. Manufacturing (Mbbbls/d)						
Lima Refinery	163.1	—	—	149.6	—	—
Wood River and Borger Refineries ⁽¹⁾	211.7	11	191.1	197.1	3	191.5
Toledo Refinery ⁽¹⁾	71.0	—	—	68.3	—	—
U.S. Manufacturing Total	445.8	133	191.1	415.0	117	191.5
Total Throughput (Mbbbls/d)	554.1	190	191.1	521.0	172	191.5
Retail (millions of litres/d)						
Fuel sales, including wholesale	7.3	—	—	6.9	—	—

(1) Represents Cenovus's 50 percent interest in Sunrise, Wood River, Borger and Toledo operations.

(2) Oil Sands production is comprised of bitumen except for Lloydminster Cold/EOR, which is comprised of medium crude oil and heavy crude oil. For the three and nine months ended September 30, 2021, Lloydminster Cold/EOR heavy crude oil production was 19.3 thousand barrels per day and 19.4 thousand barrels per day, respectively. For the three and nine months ended September 30, 2021, Lloydminster Cold/EOR medium crude oil production was 1.2 thousand barrels per day.

(3) Conventional natural gas product type.

(4) Refer to the Conventional Operating Results section of this MD&A for a summary of Conventional production by product type.

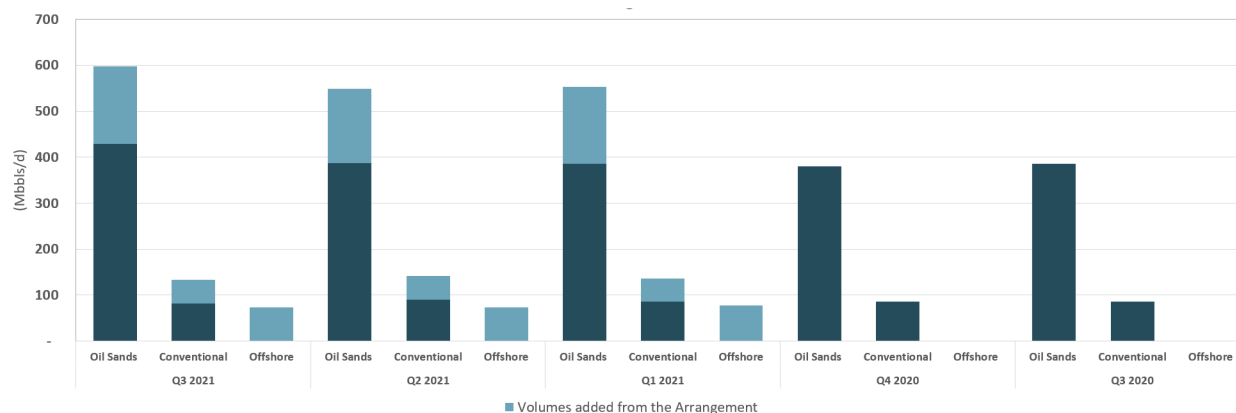
(5) Reported production volumes reflect Cenovus's 40 percent interest in the Madura-BD gas project. Revenues and expenses related to the HCML joint venture are accounted for using the equity method for consolidated financial statement purposes.

(6) Refer to the Asia Pacific Operating Results section of this MD&A for a summary of Asia Pacific production by product type.

(7) Refer to the Atlantic Operating Results section of this MD&A for a summary of Atlantic production by product type.

(8) Has been reduced for natural gas volumes used for internal consumption by the Oil Sands segment of 504 MMcf/d and 511 MMcf/d for the three and nine months ended September 30, 2021, respectively (321 MMcf/d and 333 MMcf/d for the three and nine months ended September 30, 2020, respectively).

Upstream Production Volumes



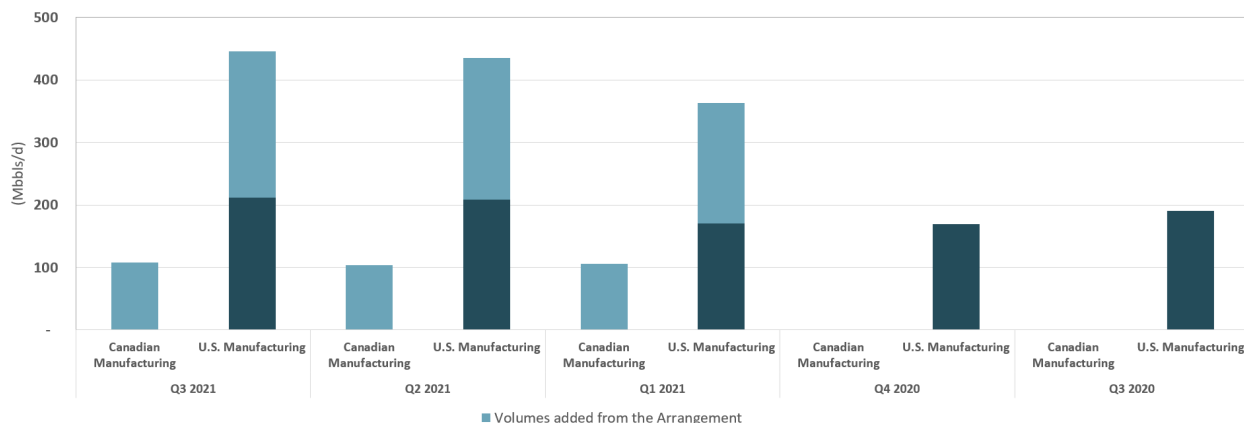
Our Oil Sands assets continued their strong performance from the first six months of 2021. Foster Creek and Christina Lake increased production from the first and second quarters as new wells came online. We achieved single-day record production at both assets. Assets acquired in the Arrangement averaged 167.4 thousand barrels per day in the third quarter. Our Lloydminster thermal assets continued to perform well as we apply our operating strategy and production and well delivery techniques.

Conventional production decreased in the third quarter primarily due to the disposition of assets in the East Clearwater and Kaybob areas, which produced approximately 11.0 thousand BOE per day. Assets acquired in the Arrangement continued their strong performance, averaging 51.5 thousand BOE per day during the quarter.

In the third quarter, Offshore production was relatively flat compared with the first six months of 2021. Offshore production is entirely from assets acquired in the Arrangement.

Downstream Manufacturing

Crude Throughput by Segment



Crude throughput increased in the third quarter as the market for refined products continued to improve. Our U.S. refineries averaged a crude utilization rate of 89 percent driven by increased demand, partially offset by the impact of planned and unplanned outages. The Lloydminster Upgrader and Lloydminster Refinery ran at or near capacity throughout the first nine months of 2021.

At the Wood River and Borger refineries, throughput was temporarily impacted by unplanned outages during the third quarter.

We maintained high throughput rates at the Lima Refinery in the third quarter. Production slowed at the end of September as we prepared for a turnaround to be completed in the fourth quarter.

At the Toledo Refinery, throughput was optimized in line with market demand in the first nine months of 2021.

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 interim Consolidated Financial Statements.

Selected Consolidated Financial Results

Operating Margin

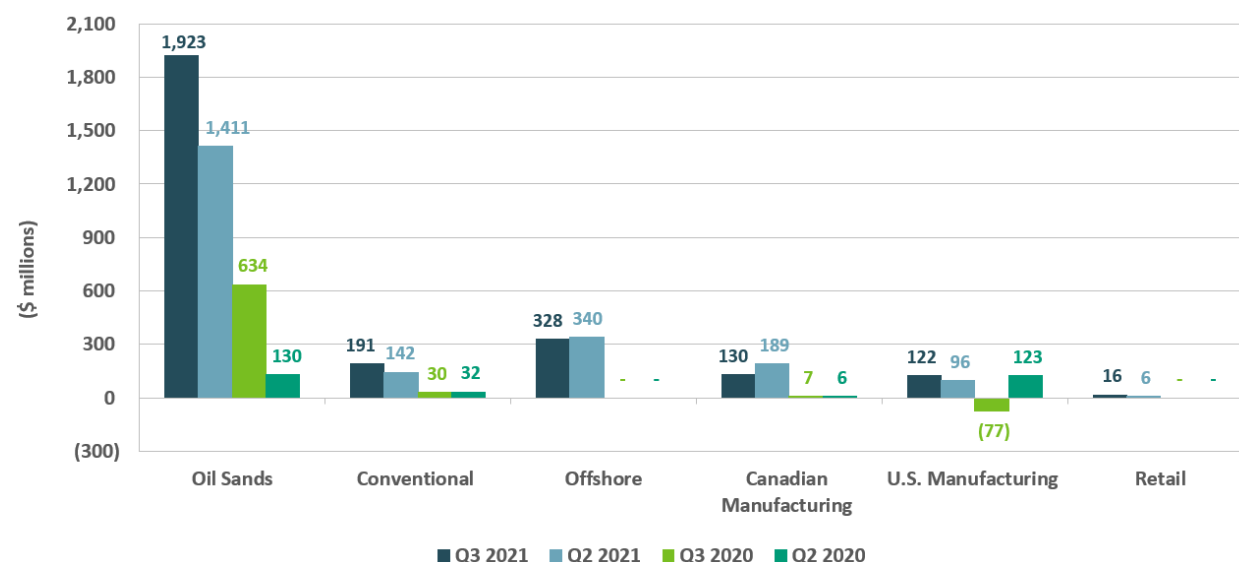
Operating Margin is an additional subtotal found in Note 1 of the interim Consolidated Financial Statements and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Margin is defined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

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020 ⁽¹⁾	2021	2020 ⁽¹⁾
Gross Sales	14,881	3,920	37,939	10,444
Less: Royalties	733	153	1,639	228
Revenues	14,148	3,767	36,300	10,216
Expenses				
Purchased Product	7,975	1,444	19,405	4,403
Transportation and Blending	1,941	1,036	5,543	3,615
Operating Expenses	1,337	554	3,945	1,680
Realized (Gain) Loss on Risk Management Activities	185	139	634	222
Operating Margin	2,710	594	6,773	296

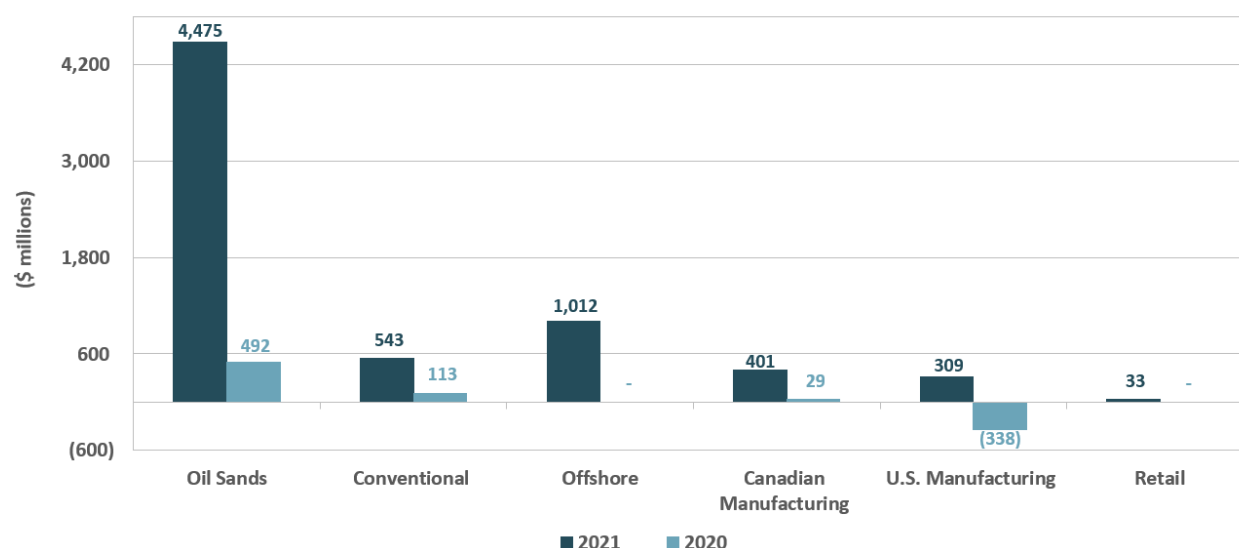
(1) Inventory write-downs prior to January 1, 2021, have been reclassified to royalties, purchased product, transportation and blending or operating expenses to conform with the current presentation of inventory write-downs.

Operating Margin by Segment

Three Months Ended September 30, 2021



Nine Months Ended September 30, 2021



Operating Margin increased in the three and nine months ended September 30, 2021, compared with 2020 primarily due to:

- Higher average crude oil, NGLs and natural gas sales prices resulting from higher benchmark pricing.
- Increased upstream sales volumes from assets acquired in the Arrangement.
- Increased sales at Foster Creek and Christina Lake.
- Higher crude throughput and 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 realized risk management losses due to the settlement of benchmark prices relative to our risk management contract prices.
- Higher Renewable Identification Numbers ("RINs") pricing impacting our U.S. Manufacturing segment.

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

Adjusted Funds Flow is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations. Adjusted Funds Flow is defined as cash from (used in) operating activities excluding settlement of decommissioning liabilities and net change in non-cash working capital. Non-cash working capital is composed of accounts receivable, inventories (excluding non-cash inventory write-downs and reversals), income tax receivable, accounts payable and income tax payable.

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Cash From (Used in) Operating Activities	2,138	732	3,735	23
(Add) Deduct:				
Settlement of Decommissioning Liabilities	(38)	(3)	(67)	(36)
Net Change in Non-Cash Working Capital	(166)	328	(1,498)	275
Adjusted Funds Flow⁽¹⁾	2,342	407	5,300	(216)

(1) The comparative period has been restated to conform with the current period definition of Adjusted Funds Flow.

Cash From Operating Activities and Adjusted Funds Flow were higher in the three months ended September 30, 2021, compared with 2020 due to increased Operating Margin, as discussed above. The increase was partially offset by:

- Higher finance costs due to interest expense on long-term debt assumed as part of the Arrangement, and a \$115 million net premium on the redemption of long-term debt in the third quarter of 2021.
- Increased general and administrative expenses due to a larger workforce resulting from the Arrangement.
- Contingent payment of \$90 million, of which \$56 million was recognized as a reduction to Cash from Operating Activities in the third quarter.
- Integration costs of \$45 million.

The change in non-cash working capital in the third quarter of 2021 was primarily due to an increase in inventories and accounts receivable, partially offset by an increase in accounts payable on September 30, 2021, compared with June 30, 2021.

In the three months ended September 30, 2021, the increase in accounts receivable was primarily due to higher commodity prices and sales volumes, partially offset by the receipt of insurance proceeds from the Superior Refinery rebuild project. The increase in inventory was primarily due to higher crude oil and refined product prices, higher volumes held in inventory in the Atlantic region due to the timing of liftings, and higher volumes held in inventory at the Wood River and Borger refineries. The increases were partially offset by lower crude oil volumes held at Foster Creek and Christina Lake. The increase in accounts payable relates to higher condensate prices in the Oil Sands segment, higher feedstock prices in the U.S. Manufacturing segment, and higher accrued royalties, contingent payment, and income taxes payable.

Cash From Operating Activities and Adjusted Funds Flow were higher in the nine months ended September 30, 2021, compared with the first nine months of 2020 due to increased Operating Margin, as discussed above, and distributions received from equity-accounted affiliates. The increase was partially offset by:

- Integration costs of \$302 million.
- Higher finance costs due to interest expense on long-term debt assumed as part of the Arrangement, and a \$115 million net premium on the redemption of long-term debt in the third quarter of 2021.
- Increased general and administrative expenses due to a larger workforce resulting from the Arrangement.
- Long-term incentives of \$111 million paid related to the accelerated payout to our employees in connection with the Arrangement.

The change in non-cash working capital in the first nine months of 2021 was primarily due to an increase in inventories and accounts receivable, partially offset by an increase in accounts payable on September 30, 2021, compared with December 31, 2020.

In the nine months ended September 30, 2021, the increase in accounts receivable was primarily due to the higher crude oil pricing in the Oil Sands segment and higher refined product pricing in the U.S. Manufacturing segment, partially offset by the receipt of insurance proceeds from the Superior Refinery rebuild project. The increase in inventory was primarily due to higher commodity prices and higher volumes held in inventory at Foster Creek and Christina Lake. The increase in accounts payable was primarily due to higher condensate prices in the Oil Sands segment, and higher accrued royalties payable, risk management liabilities, contingent payment, and income taxes payable. The increases were partially offset by the settlement of integration costs, long-term incentive costs to Cenovus employees and the payment of long-term incentives liability assumed as part of the Arrangement.

Net Earnings (Loss)

(\$ millions)	Three Months Ended	Nine Months Ended
Net Earnings (Loss) for the Periods Ended September 30, 2020	(194)	(2,226)
Increase (Decrease) due to:		
Operating Margin	2,116	6,477
Corporate and Eliminations:		
Unrealized Foreign Exchange Gain (Loss)	(251)	449
Re-measurement of Contingent Payment	(166)	(668)
Integration costs	(45)	(302)
General and Administrative	(107)	(367)
Finance costs	(215)	(445)
Other ⁽¹⁾	28	41
Unrealized Risk Management Gain (Loss)	(113)	(235)
Depreciation, Depletion and Amortization	(61)	(619)
Exploration Expense	20	17
Income Tax Recovery (Expense)	(461)	(1,127)
Net Earnings (Loss) for the Periods Ended September 30, 2021	551	995

(1) Includes interest income, realized foreign exchange (gains) losses, (gain) loss on divestiture of assets, other (income) loss, net, and 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 the third quarter of 2021 was significantly higher than the Net Loss in 2020 due to higher Operating Margin, as discussed above, an impairment loss of \$450 million in the third quarter of 2020 and higher other income. The increase was partially offset by:

- Unrealized foreign exchange losses compared with gains in 2020.
- A loss on the re-measurement of the contingent payment of \$135 million (2020 – \$31 million gain).
- Lower unrealized risk management gains.
- Net premiums of \$115 million on the redemption of long-term debt.
- Increased general and administrative costs, finance expenses, depreciation, depletion and amortization (“DD&A”) expense and income tax expense as a result of the Arrangement.

On a year-to-date basis, Net Earnings was significantly higher than the Net Loss in the first nine months of 2020 due to:

- Higher Operating Margin, as discussed above.
- Impairment losses of \$765 million in the first nine months of 2020.
- Gains on unrealized foreign exchange compared with losses in 2020.
- Higher other income.

The increase was partially offset by:

- A loss on the re-measurement of the contingent payment of \$571 million (2020 – \$97 million gain).
- Integration costs of \$302 million.
- Higher unrealized risk management losses.
- Net premiums of \$115 million on the redemption of long-term debt, compared with a net discount of \$25 million in 2020.
- Higher general and administrative costs, finance costs, DD&A expense and income tax expense as a result of the Arrangement.

Net Debt

Net Debt is a non-GAAP measure used to monitor our capital structure. Net Debt is defined 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.

(\$ millions) As at	September 30, 2021	December 31, 2020
Short-Term Borrowings	48	121
Long-Term Debt, including current portion	12,986	7,441
Less: Cash and Cash Equivalents	(2,010)	(378)
Net Debt	11,024	7,184

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 Net Debt by \$2.1 billion, including \$1.4 billion during the third quarter of 2021.

Capital Investment ^{(1) (2)}

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Upstream				
Oil Sands	198	65	617	337
Conventional	41	12	135	39
Offshore	69	—	130	—
	308	77	882	376
Downstream				
Canadian Manufacturing	9	5	23	22
U.S. Manufacturing	301	60	743	150
Retail	16	—	22	—
	326	65	788	172
Corporate and Eliminations	13	6	58	51
Capital Investment	647	148	1,728	599

(1) Includes expenditures on PP&E and E&E assets.

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

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

Conventional capital investment focused on predictable 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 the first nine months of 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.

Drilling Activity

Nine months ended September 30,	Gross Stratigraphic Test Wells		Gross Production Wells ⁽¹⁾	
	2021	2020	2021	2020
Foster Creek	17	38	6	—
Christina Lake	25	42	9	—
Lloydminster Thermal	—	—	21	—
Lloydminster Cold/EOR	—	—	2	—
Other ⁽²⁾	17	75	—	—
	59	155	38	—

(1) Steam-assisted gravity drainage ("SAGD") well pairs in the Oil Sands segment are counted as a single producing well.

(2) Includes Narrows Lake and 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.

(net wells, unless otherwise stated)	Nine Months Ended September 30, 2021			Nine Months Ended September 30, 2020		
	Drilled	Completed	Tied-in	Drilled	Completed	Tied-in
Conventional	14	17	18	—	—	2

There were no wells drilled, completed or tied-in during the first nine months of 2021 in the Offshore segment. We drilled a planned exploration well in China in October 2021.

Future Capital Investment

Our Oil Sands capital investment for 2021 is forecast to be between \$950 million and \$1,050 million, focused primarily on sustaining production at Christina Lake, Foster Creek and the Lloydminster thermal assets. Our Oil Sands production is expected to range between 540.0 thousand barrels per day and 596.0 thousand barrels per day.

Our Conventional capital investment for 2021 is forecast to be between \$170 million and \$210 million. This includes economic development in various plays to generate strong returns, improve underlying cost structures through volume enhancement and offset declines. Our Conventional production is expected to range between 131.0 thousand BOE per day and 140.0 thousand BOE per day.

Our Offshore capital investment for 2021 is expected to be between \$200 million and \$250 million. This capital spend includes a planned well in China as well as preservation capital for the West White Rose project. Production from our Offshore segment is expected to range between 66.0 thousand BOE per day and 74.0 thousand BOE per day.

In 2021, we plan to invest between \$900 million and \$1.1 billion in the U.S. Manufacturing, Canadian Manufacturing and Retail segments and will continue to focus on refining reliability and maintenance, safety projects and high-return optimization opportunities. We also plan to invest between \$520 million and \$570 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 500.0 thousand barrels per day to 550.0 thousand barrels per day.

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

Our guidance dated July 28, 2021, is available on our website at cenovus.com.

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 the U.S./Canadian dollar and RMB/Canadian dollar average exchange rates to assist in understanding our financial results.

Selected Benchmark Prices and Exchange Rates ⁽¹⁾

Nine months ended September 30,						
(Average US\$/bbl, unless otherwise indicated)	2021	Percent Change	2020	Q3 2021	Q2 2021	Q3 2020
Brent ⁽²⁾	67.73	66	40.82	73.47	68.83	42.99
WTI	64.82	69	38.32	70.56	66.07	40.93
Differential Brent-WTI	2.91	16	2.50	2.91	2.76	2.06
WCS at Hardisty ("WCS")	52.31	112	24.63	56.98	54.58	31.84
Differential WTI-WCS	12.51	(9)	13.69	13.58	11.49	9.09
WCS (C\$/bbl)	65.41	98	32.98	71.80	66.99	42.41
WCS at Nederland	61.58	79	34.36	65.79	63.03	38.73
Differential WTI-WCS at Nederland	3.24	(18)	3.96	4.77	3.04	2.20
Condensate (C\$ @ Edmonton)	64.56	82	35.38	69.24	66.40	37.55
Differential WTI-Condensate (Premium)/Discount	0.26	(91)	2.94	1.32	(0.33)	3.38
Differential WCS-Condensate (Premium)/Discount	(12.25)	14	(10.75)	(12.26)	(11.82)	(5.71)
Average (C\$/bbl)	80.73	70	47.47	87.18	81.51	49.99
Synthetic @ Edmonton	63.24	80	35.13	68.98	66.41	38.47
WTI-Synthetic (Premium)/Discount Differential	1.58	(50)	3.19	1.58	(0.34)	2.46
Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	82.81	86	44.55	91.90	87.03	48.75
Chicago Ultra-low Sulphur Diesel ("ULSD")	82.99	70	48.71	89.96	85.73	48.91
Refining Benchmarks						
Chicago 3-2-1 Crack Spread ⁽³⁾	18.04	134	7.71	20.67	20.50	7.89
Group 3 3-2-1 Crack Spread ⁽³⁾	18.49	105	9.04	20.35	19.44	8.29
RINs	6.97	225	2.14	7.32	8.12	2.64
Natural Gas Prices						
AECO ⁽⁴⁾ (C\$/Mcf)	3.11	50	2.07	3.54	2.85	2.15
NYMEX (US\$/Mcf)	3.18	69	1.88	4.01	2.83	1.98
Foreign Exchange Rate						
US\$ per C\$1 - Average	0.799	8	0.739	0.794	0.814	0.751
US\$ per C\$1 - End of Period	0.785	8	0.730	0.785	0.807	0.750
RMB per C\$1 - Average	5.172	—	5.168	5.136	5.259	5.192

(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.

(4) Alberta Energy Company ("AECO") natural gas monthly index.

Crude Oil and Condensate Benchmarks

In the third quarter, Brent and WTI crude oil benchmarks continued to improve due to increased global crude oil demand amid roll out efforts of COVID-19 vaccines, economic recovery and declines in crude oil inventories. 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.

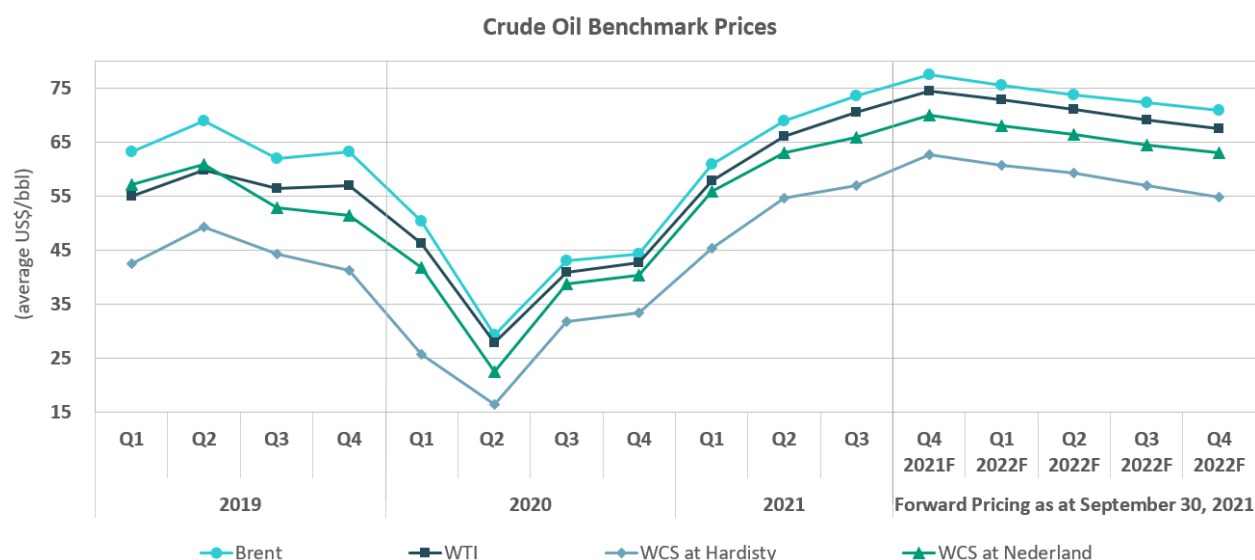
The price received for our Atlantic crude oil and Asia Pacific NGLs is primarily driven by the price of Brent.

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 the third quarter, the Brent-WTI differential remained narrow 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 the third quarter, the average WTI-WCS differential widened slightly compared with the first half of 2021 and the third quarter of 2020 due to modest increases to production and inventory levels. Average differentials in the first nine months of 2021 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 the third quarter of 2021, consistent with increasing crude oil prices globally, as refiners increased crude runs to adjust to increased demand for products. In the third quarter, 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.

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 discount relative to WTI in the third quarter of 2021. The differential has narrowed compared with the third quarter of 2020 as a result of higher oil sands production leading to an increase in blending requirements.

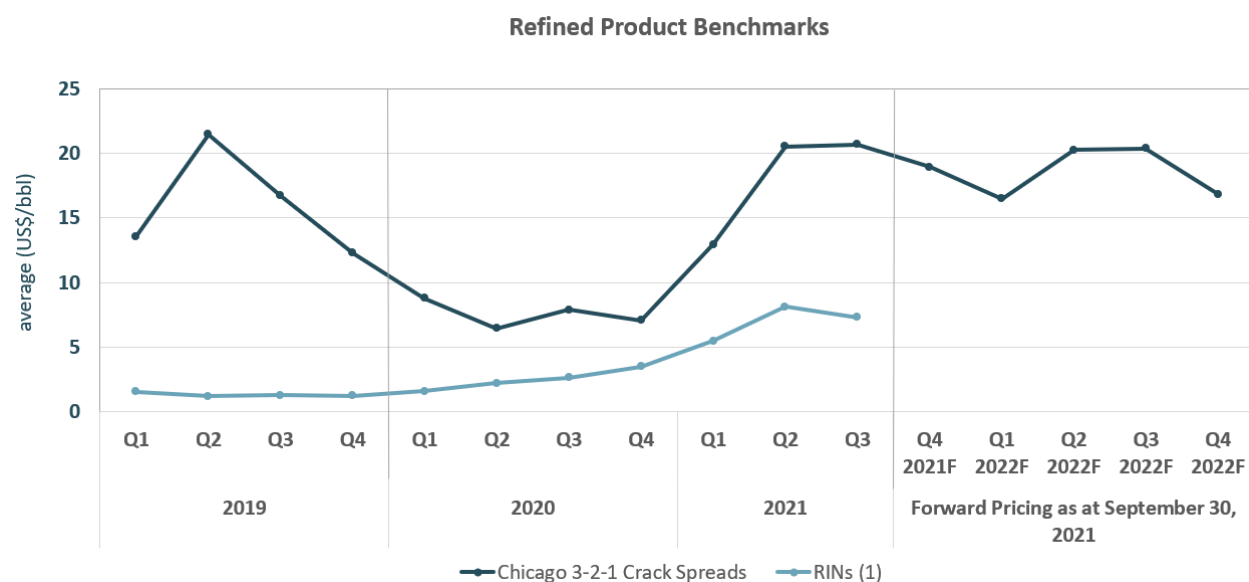
Refining Benchmarks

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 the third quarter of 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 and increasing 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) RINs forward price information is unavailable after September 30, 2021.

Natural Gas Benchmarks

Average NYMEX natural gas prices increased significantly in the third quarter as hot weather, a strong rebound in U.S. domestic demand, and record liquified natural gas exports coupled with a muted supply response supported the market. Average AECO prices improved alongside the NYMEX benchmark. The differential between AECO and NYMEX widened in the third quarter 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.

The Canadian dollar on average strengthened relative to the U.S. dollar compared with 2020, resulting in a negative impact on our revenues. The Canadian dollar relative to the U.S. dollar as at September 30, 2021, compared with December 31, 2020 was flat. Combined with the realization of foreign exchange losses of \$139 million on the repayment of our unsecured notes, this resulted in unrealized foreign exchange gains of \$132 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 Cold/EOR, which produces heavy oil from the Lloydminster region of Alberta and Saskatchewan.
- 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 the third quarter of 2021, we:

- Delivered safe and reliable operations.
- Completed scheduled maintenance at three of our plants at our Lloydminster thermal assets.
- Achieved record single-day production at Foster Creek and Christina Lake.
- Produced 597.0 thousand barrels per day, compared with 551.5 thousand barrels per day in the first six months of 2021.
- Generated Operating Margin of \$1.9 billion, an increase of \$1.3 billion compared with the third quarter of 2020 primarily due to higher average realized sales prices, added volumes from assets acquired as part of the Arrangement and higher volumes at Foster Creek and Christina Lake.
- Earned a Netback of \$36.98 per BOE.

Three Months Ended September 30, 2021 Compared With Three Months Ended September 30, 2020

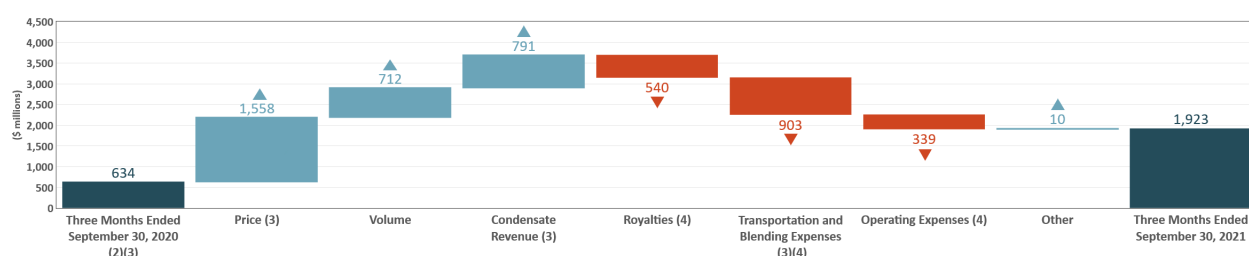
Financial Results

(\$ millions)	Three Months Ended September 30,	
	2021	2020 ⁽¹⁾
Gross Sales	6,114	2,436
Less: Royalties	669	129
Revenues	5,445	2,307
Expenses		
Purchased Product	822	235
Transportation and Blending	1,918	1,015
Operating	616	286
Realized (Gain) Loss on Risk Management	166	137
Operating Margin	1,923	634
Unrealized (Gain) Loss on Risk Management ⁽²⁾	(39)	(135)
Depreciation, Depletion and Amortization	743	470
Exploration Expense	2	—
Segment Income (Loss)	1,217	299

(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.

Operating Margin Variance ⁽¹⁾



(1) Other includes third party sourced volumes, construction and other activities not attributable to the production of crude oil, NGLs or natural gas.

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

(3) 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.

(4) 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 Results

	Three Months Ended September 30,	
	2021	2020
Total Sales Volumes (MBOE/d)	613.1	396.4
Total Realized Price per Unit Sold (\$/BOE)	66.78	39.67
Crude Oil Production by asset (Mbbls/d)		
Foster Creek	187.1	165.0
Christina Lake	242.5	221.0
Sunrise ⁽¹⁾	28.3	—
Lloydminster Thermal	98.0	—
Tucker	20.6	—
Lloydminster Cold/EOR	20.5	—
Total Daily Crude Oil Production ⁽²⁾	597.0	386.0
Effective Royalty Rate (percent)	19.9	11.0
Per Unit Transportation and Blending Cost (\$/BOE)	7.09	7.51
Per Unit Operating Cost (\$/BOE)	10.86	7.53

(1) Represents Cenovus's 50 percent interest in Sunrise operations.

(2) Oil Sands production is comprised of bitumen except for Lloydminster Cold/EOR, which is comprised of medium crude oil and heavy crude oil. For the three months ended September 30, 2021, Lloydminster Cold/EOR heavy crude oil production was 19.3 thousand barrels per day. For the three months ended September 30, 2021, Lloydminster cold/EOR medium crude oil production was 1.2 thousand barrels per day.

Revenues

Price

In the third quarter of 2021, our realized sales price was \$66.78 per BOE compared with \$39.67 per BOE in the third quarter of 2020. The increase in realized sales price was primarily due to higher WTI benchmark prices (US\$70.56 per barrel compared with US\$40.93 per barrel in the third quarter of 2020), partially offset by wider WTI-WCS differentials. In the third quarter of 2021, we sold approximately 25 percent (2020 – 20 percent) of our production to U.S. destinations to improve our realized sales price.

In the third quarter of 2021, gross sales included \$755 million (2020 – \$241 million) 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 the third quarter of 2021, gross sales included other amounts of \$55 million (2020 – \$1 million), which are not included in our per-unit pricing metrics or our Netbacks as it relates to construction, transportation and blending 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 using our marketing and transportation infrastructure, including storage and pipeline assets to optimize product mix, delivery points, transportation commitments and customer diversification. 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, 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 third quarter of 2021, we incurred a realized risk management loss due to the settlement of benchmark prices relative to our risk management contract prices; the underlying physical inventory sold in the quarter recognized a gain due to rising benchmark prices. In the third quarter of 2021, unrealized gains were recorded on our crude oil financial instruments primarily due to forward benchmark pricing falling below our risk management contract prices that related to future periods and the realization of settled positions. In a rising commodity price environment, we would expect to realize losses on our risk

management activities but recognize gains on the underlying physical inventory sold in the period and the opposite to occur in a falling commodity price environment.

Production Volumes

Oil Sands crude oil production was 597.0 thousand barrels per day in the third quarter of 2021, an increase of 211.0 thousand compared with the third quarter of 2020.

Production levels increased year-over-year primarily due to 167.4 thousand barrels per day from assets acquired as part of the Arrangement, and increased production at Foster Creek and Christina Lake. Lloydminster thermal production remains strong as we continue to apply our operating strategy and production and well delivery techniques. Our Sunrise and Tucker assets produced at stable rates.

Production at Foster Creek increased 22.1 thousand barrels per day year-over-year due to new wells coming online.

Production at Christina Lake increased 21.5 thousand barrels per day year-over-year due to new wells coming online, combined with a planned turnaround and maintenance activities in the third quarter of 2020.

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 Cold/EOR, 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 production, all of which was acquired as part of the Arrangement.

Royalties increased by \$540 million compared with the third quarter of 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 \$796 million in the third quarter of 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 Cold/EOR assets typically have lower blending rates due to lower crude oil viscosity.

Transportation costs increased \$107 million to \$380 million in the third quarter of 2021 compared with 2020, primarily due to assets acquired in the Arrangement, increased volumes shipped and sold to U.S. destinations via pipeline to obtain higher sales prices, and higher volumes shipped to U.S. destinations via rail.

Per-unit Transportation Expenses

Per-unit transportation costs were \$7.09 per BOE in the third quarter of 2021 (2020 – \$7.51 per BOE). The decrease was mainly a result of our ability to optimize combined pipeline capacity out of Alberta following the Arrangement. Also contributing to the decrease were lower per-unit transportation costs at Tucker, Lloydminster thermal, and Lloydminster Cold/EOR, compared with Foster Creek, Christina Lake and Sunrise. The decrease was partially offset by the temporary suspension of our crude-by-rail program in the third quarter of 2020.

At Foster Creek, per-unit transportation costs increased 18 percent compared with 2020 to \$10.14 per barrel as we shipped 40 percent (2020 – 30 percent) of our volumes to U.S. destinations to obtain higher realized prices. In addition, 15 percent (2020 – nil) of our volumes shipped to U.S. destinations were via rail.

At Christina Lake, per-unit transportation costs were \$5.74 per barrel in the third quarter of 2021 (2020 – \$6.78 per barrel) as we shipped less volumes to the USGC.

Operating

Primary drivers of our operating expenses in the third quarter of 2021 were fuel, workforce, chemical costs, and repairs and maintenance. Total operating costs increased primarily due to assets acquired from the Arrangement which have higher per barrel operating costs and higher natural gas prices year-over-year.

(\$/bbl)	Three Months Ended September 30,	
	2021	Percent Change
Foster Creek		
Fuel	4.15	60
Non-Fuel	6.05	(6)
Total	10.20	13
Christina Lake		
Fuel	3.53	74
Non-Fuel	4.30	(4)
Total	7.83	20
Other Oil Sands ⁽¹⁾		
Fuel	4.84	—
Non-Fuel	10.95	—
Total	15.79	—
Total	10.86	44

⁽¹⁾ Includes Sunrise, Tucker, Lloydminster thermal and Lloydminster Cold/EOR assets.

At both Foster Creek and Christina Lake, per-unit fuel costs increased primarily due to higher natural gas prices, partially offset by higher sales volumes. Per-unit non-fuel costs at Foster Creek decreased due to higher sales volumes, partially offset by higher chemical costs. Non-fuel costs at Christina Lake were relatively flat year-over-year.

Total unit operating costs for all assets increased \$3.33 per BOE to \$10.86 per BOE in the third quarter of 2021 compared with the same period of 2020. The increase was due to higher per-unit operating costs of the assets acquired in the Arrangement, and increased Foster Creek and Christina Lake per-unit costs as discussed above.

Netbacks ^{(1) (2)}

Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis. Our Netback calculation is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook. 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. For a reconciliation of our Netbacks see the Advisory section of this MD&A.

(\$/BOE)	Three Months Ended September 30,	
	2021	2020
Sales Price	66.78	39.67
Royalties ⁽¹⁾	11.85	3.54
Transportation and Blending ^{(1) (2)}	7.09	7.51
Operating Expenses ⁽¹⁾	10.86	7.53
Netback	36.98	21.09

⁽¹⁾ Netbacks do not reflect non-cash write-downs of product inventory or reversals of product inventory until realized when the product is sold.

⁽²⁾ Netbacks reflect our margin on a per-barrel basis of unblended crude oil.

Nine Months Ended September 30, 2021 Compared With Nine Months Ended September 30, 2020

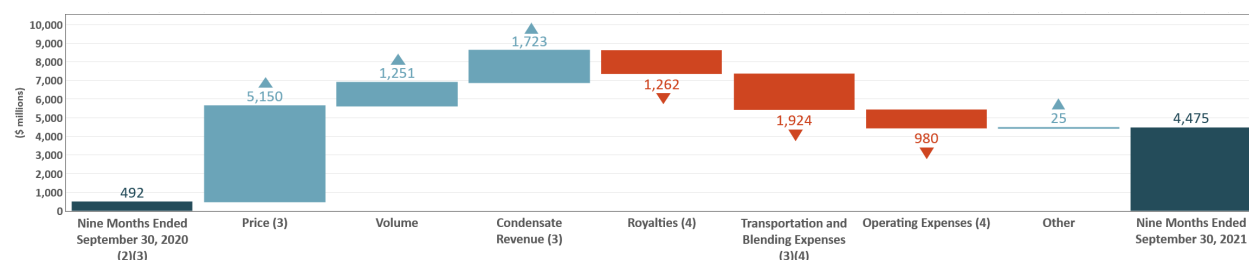
Financial Results

(\$ millions)	Nine Months Ended September 30,	
	2021	2020 ⁽¹⁾
Gross Sales	15,904	6,117
Less: Royalties	1,462	200
Revenues	14,442	5,917
Expenses		
Purchased Product	2,114	806
Transportation and Blending	5,476	3,552
Operating	1,793	839
Realized (Gain) Loss on Risk Management	584	228
Operating Margin	4,475	492
Unrealized (Gain) Loss on Risk Management ⁽²⁾	194	8
Depreciation, Depletion and Amortization	1,982	1,276
Exploration Expense	15	7
Share of (Income) Loss from Equity-Accounted Affiliates	(5)	—
Segment Income (Loss)	2,289	(799)

(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.

Operating Margin Variance ⁽¹⁾



(1) Other includes third party sourced volumes, construction and other activities not attributable to the production of crude oil, NGLs or natural gas.

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

(3) 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.

(4) 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 Results

	Nine Months Ended September 30,	
	2021	2020
Total Sales Volumes (MBOE/d)	571.4	388.2
Total Realized Price per Unit Sold (\$/BOE)	60.51	25.21
Crude Oil Production by asset (Mbbls/d)		
Foster Creek	169.1	164.9
Christina Lake	232.0	217.1
Sunrise ⁽¹⁾	26.1	—
Lloydminster Thermal	97.3	—
Tucker	21.7	—
Lloydminster Cold/EOR	20.6	—
Total Daily Crude Oil Production ⁽²⁾	566.8	382.0
Effective Royalty Rate (percent)	17.6	11.4
Per Unit Transportation and Blending Cost (\$/BOE)	7.40	8.97
Per Unit Operating Cost (\$/BOE)	11.42	7.55

(1) Represents Cenovus's 50 percent interest in Sunrise operations.

(2) Oil Sands production is comprised of bitumen except for Lloydminster cold/EOR, which is comprised of medium crude oil and heavy crude oil. For the nine months ended September 30, 2021, Lloydminster Cold/EOR heavy crude oil production was 19.4 thousand barrels per day. For the nine months ended September 30, 2021, Lloydminster Cold/EOR medium crude oil production was 1.2 thousand barrels per day.

Revenues

Price

The increase in realized sales price was primarily due to higher WTI benchmark prices and narrower WTI-WCS differentials. In the first nine months of 2021, we sold approximately 20 percent (2020 – 25 percent) of our production to U.S. destinations to improve our realized sales price.

In the first nine months of 2021, gross sales included \$1.9 billion (2020 – \$828 million) 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 the first nine months of 2021, gross sales included other amounts of \$208 million (2020 – \$8 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.

In the nine months ended September 30, 2021, we incurred a realized risk management loss due to the settlement of benchmark prices relative to our risk management contract prices; the underlying physical inventory sold recognized an offsetting gain due to rising benchmark prices. In the first nine months of 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 566.8 thousand barrels per day in the first nine months of 2021, an increase of 184.8 thousand barrels per day compared with 2020. Production levels increased primarily due to the addition of 165.7 thousand barrels per day from assets acquired as part of the Arrangement, and increased production at Foster Creek and Christina Lake. Lloydminster thermal achieved record single day production rates in the first quarter and continued to produce at high rates through the end of the third quarter. We had a planned turnaround at Sunrise in the second quarter which impacted production and contributed to increased production in the third quarter. Tucker produced at stable rates.

Production at Foster Creek increased year-over-year due to new wells coming online, partially offset by a planned turnaround and operational outages in the second quarter of 2021.

Production at Christina Lake increased 14.9 thousand barrels per day year-over-year due to new wells coming online combined with our decision to operate at reduced levels in April 2020 and a planned turnaround and maintenance activities in the third quarter of 2020.

Royalties

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 production, all of which was acquired as part of the Arrangement.

Royalties increased by \$1.3 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 \$1.7 billion in the first nine months of 2021 compared with 2020. At Foster Creek and Christina Lake, blending costs increased from 2020 due to higher condensate prices and volumes.

Transportation costs increased \$201 million to \$1.2 billion in the first nine months of 2021 compared with 2020, primarily due to assets acquired in the Arrangement, increased volumes shipped and sold to U.S. destinations via pipeline to obtain higher sales prices, partially offset by lower volumes shipped to U.S. destinations via rail.

Per-unit Transportation Expenses

Per-unit transportation costs were \$7.40 per BOE in the first nine months of 2021 (2020 – \$8.97 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 Tucker, Lloydminster thermal, and Lloydminster Cold/EOR compared with Foster Creek, Christina Lake and Sunrise.

At Foster Creek, per-unit transportation costs decreased 4 percent from 2020 to \$10.98 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 to obtain higher realized prices, of which 15 percent (2020 – 35 percent) were via rail.

At Christina Lake, per-unit transportation costs decreased 13 percent from 2020 to \$6.15 per barrel as less than five percent (2020 – 20 percent) of our volumes shipped to U.S. destinations were via rail.

Operating

Primary drivers of our operating expenses in the first nine months of 2021 were fuel, workforce, chemical costs, and repairs and maintenance. Total operating costs increased primarily due to 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.

	Nine Months Ended September 30,		
(\$/BOE)	2021	Percent Change	2020
Foster Creek			
Fuel	3.92	51	2.60
Non-Fuel	6.98	11	6.28
Total	10.90	23	8.88
Christina Lake			
Fuel	3.23	59	2.03
Non-Fuel	4.81	6	4.53
Total	8.04	23	6.56
Other Oil Sands ⁽¹⁾			
Fuel	4.39	—	—
Non-Fuel	11.89	—	—
Total	16.28	—	—
Total	11.42	51	7.55

(1) Includes Sunrise, Tucker, Lloydminster Thermal and Lloydminster Cold/EOR assets.

At both Foster Creek and Christina Lake, per BOE fuel costs increased primarily due to higher natural gas prices. Non-fuel costs increased at Foster Creek primarily due to the planned turnaround in the second quarter of 2021, and higher electricity and chemical costs. Non-fuel costs increased at Christina Lake primarily due to higher electricity and chemical costs. In addition, we had reduced repairs and maintenance activity at Foster Creek and Christina Lake in the first nine months of 2020 due to COVID-19 safety measures.

Total unit operating costs for all assets increased \$3.87 per BOE to \$11.42 per BOE in the first nine months of 2021 compared with the same period of 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.

DD&A

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

In the three and nine months ended September 30, 2021, DD&A increased \$273 million and \$706 million, respectively, compared with the same period in 2020 primarily as a result of the Arrangement. The average depletion rate for the three and nine months ended September 30, 2021, was \$11.45 per BOE and \$11.37 per BOE, respectively (2020 – \$10.35 per BOE and \$10.40 per BOE, respectively).

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.

Netbacks^{(1) (2)}

(\$/bbl)	Nine Months Ended September 30,	
	2021	2020
Sales Price	60.51	25.21
Royalties ⁽¹⁾	9.37	1.88
Transportation and Blending ^{(1) (2)}	7.40	8.97
Operating Expenses ⁽¹⁾	11.42	7.55
Netback	32.32	6.81

(1) Netbacks do not reflect non-cash write-downs of product inventory or reversals of product inventory until realized when the product is sold.

(2) Netbacks reflect our margin on a per-barrel basis of unblended crude oil.

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 the third quarter of 2021, we:

- Delivered safe and reliable operations.
- Generated Operating Margin of \$191 million, an increase of \$161 million compared with the third quarter of 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.
- Completed numerous turnarounds involving field maintenance activities and safely shutting-in and reactivating production.
- We closed \$82 million out of approximately \$110 million in combined gross proceeds of previously announced asset sales within the Conventional segment located in the East Clearwater and Kaybob areas. The remainder of the asset sales closed in October. The assets produced approximately 11.0 thousand BOE per day.
- Achieved a Netback of \$15.91 per BOE.

Financial Results

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020 ⁽¹⁾	2021	2020 ⁽¹⁾
Gross Sales	833	232	2,235	636
Less: Royalties	40	24	103	28
Revenues	793	208	2,132	608
Expenses				
Purchased Product	445	76	1,113	184
Transportation and Blending ⁽²⁾	20	21	57	63
Operating	135	81	417	248
Realized (Gain) Loss on Risk Management	2	—	2	—
Operating Margin	191	30	543	113
Unrealized (Gain) Loss on Risk Management ⁽³⁾	9	—	10	—
Depreciation, Depletion and Amortization	99	75	309	563
Exploration Expense	—	25	(3)	25
Segment Income (Loss)	83	(70)	227	(475)

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

(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) 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

The three and nine months ended September 30, 2021, included gross sales of \$445 million and \$1.1 billion, respectively (2020 – \$76 million and \$186 million, respectively) relating to third-party sourced volumes, which are not included in our per-unit pricing metrics or our Netbacks.

In the three and nine months ended September 30, 2021, revenues included other amounts of \$10 million and \$53 million, respectively (2020 – \$11 million and \$34 million, respectively), which are not included in our per-unit pricing metrics or our Netbacks, as it relates to processing and transportation activities for third parties.

Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Total Sales Volumes (MBOE/d)	131.4	85.7	136.2	91.1
Total Realized Price per Unit Sold (\$/BOE)	31.28	18.28	28.76	16.64
Light Crude Oil (\$/bbl)	87.31	45.16	71.98	37.37
NGLs (\$/bbl)	47.37	21.38	39.79	20.26
Conventional Natural Gas (\$/Mcf)	3.85	2.34	3.69	2.18
Production by Product				
Light Crude Oil (Mbbls/d)	8.7	7.5	8.8	7.6
NGLs (Mbbls/d)	22.8	18.3	26.7	19.9
Conventional Natural Gas (MMcf/d)	603.2	360.1	605.4	382.3
Total Daily Production (MBOE/d)	132.0	85.9	136.4	91.2
Conventional Natural Gas Production (percentage of total)	76	70	74	70
Light Crude Oil and NGLs Production (percentage of total)	24	30	26	30
Effective Royalty Rate (percent)	11.2	18.5	10.2	7.7
Per Unit Transportation Cost (\$/BOE)	1.64	2.62	1.54	2.51
Per Unit Operating Cost (\$/BOE)	10.41	9.55	10.57	9.19

Revenues

Price

Our total realized sales price increased in the three and nine months ended September 30, 2021 primarily due to higher crude oil and natural gas benchmark prices.

Production Volumes

Production volumes increased in the first nine months of 2021, primarily due to 51.5 thousand BOE per day from assets acquired as part of the Arrangement. In addition, we brought 18 new net wells on production during the nine months ended September 30, 2021. The increase is partially offset by the East Clearwater and Kaybob dispositions and natural declines.

Royalties

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

Effective royalty rates for the three months ended September 30, 2021, decreased primarily due to a gas cost allowance ("GCA") adjustment of \$8 million booked in 2020.

Effective royalty rates for the nine months ended September 30, 2021, increased primarily due to higher realized pricing and lower GCA credits.

Royalties increased \$16 million and \$75 million in the three and nine months ended September 30, 2021, respectively, compared with the same periods in 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. Per-unit transportation costs averaged \$1.64 per BOE and \$1.54 per BOE in the three and nine months ended September 30, 2021, respectively (2020 – \$2.62 per BOE and \$2.51 per BOE, respectively).

Transportation costs decreased by \$1 million and \$6 million in the three and nine months ended September 30, 2021, respectively, compared with the same periods in 2020.

Operating

Primary drivers of our operating expenses in the three and nine months ended September 30, 2021, were workforce, repairs and maintenance, property tax and lease costs, and electricity. Total operating costs increased \$54 million and \$169 million in the three and nine months ended September 30, 2021, respectively, primarily due to the assets acquired in the Arrangement.

Operating costs increased \$0.86 per BOE and \$1.38 per BOE in the three and nine months ended September 30, 2021, respectively, compared with the same periods in 2020. The increase is primarily due to higher average operating costs on assets acquired as part of the Arrangement. Per-unit operating costs in the three and nine months ended September 30, 2021, excluding assets acquired in the Arrangement, increased marginally year-over-year.

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 the three and nine months ended September 30, 2021, was \$7.98 per BOE and \$8.12 per BOE, respectively (2020 – \$9.60 per BOE and \$10.00 per BOE, respectively).

For the three and nine months ended September 30, 2021, total Conventional DD&A was \$99 million and \$309 million, respectively (2020 – \$75 million and \$563 million, respectively). The increase during the quarter was due to assets acquired in the Arrangement, partially offset by a lower depletable base as a result of impairment write-downs during the year ended December 31, 2020.

On a year-to-date basis the decrease was due to an impairment write-down of \$315 million in the first quarter of 2020, and a lower depletable base as a result of further impairment write-downs during the year ended December 31, 2020. The decrease is partially offset by assets acquired in the Arrangement.

Netbacks

(\$/BOE)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Sales Price	31.28	18.28	28.76	16.64
Royalties	3.32	2.95	2.77	1.09
Transportation and Blending	1.64	2.62	1.54	2.51
Operating Expenses	10.41	9.55	10.57	9.19
Netback	15.91	3.16	13.88	3.85

OFFSHORE

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

In the third quarter of 2021, we:

- Delivered safe and reliable operations.
- Generated Operating Margin of \$328 million.
- Achieved a Netback of \$59.20 per BOE.
- Achieved single-day record production at our Indonesia assets.
- Entered into agreements with our partners to restructure our working interests on assets in the Atlantic region.

Offshore Consolidated

Financial Results

(\$ millions)	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
Gross Sales	404	1,262
Less: Royalties	24	74
Revenues	380	1,188
Expenses		
Transportation and Blending	3	10
Operating	49	166
Operating Margin	328	1,012
Depreciation, Depletion and Amortization	127	369
Exploration Expense	3	3
Share of (Income) Loss from Equity-Accounted Affiliates	(12)	(36)
Segment Income (Loss)	210	676

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 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 total estimated life of the related asset as represented by proved developed producing or proved plus probable reserves. The average depletion rate for the three and nine months ended September 30, 2021, was \$26.75 per BOE and \$25.96 per BOE, respectively.

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

Netbacks

(\$/BOE)	Three Months Ended September 30, 2021			
	China	Indonesia ⁽¹⁾	Atlantic	Total
Sales Price	73.32	65.39	94.26	74.55
Royalties	4.39	12.78	5.60	5.77
Transportation and Blending	—	—	3.99	0.46
Operating Expenses	5.87	9.55	29.44	9.12
Netback	63.06	43.06	55.23	59.20
Total Sales Volumes (MBOE/d)	49.8	10.0	7.8	67.6

(\$/BOE)	Nine Months Ended September 30, 2021			
	China	Indonesia ⁽¹⁾	Atlantic	Total
Sales Price	70.61	62.71	85.93	72.25
Royalties	3.94	9.11	6.02	4.98
Transportation and Blending	—	—	2.78	0.49
Operating Expenses	5.18	8.67	26.62	9.38
Netback	61.49	44.93	50.51	57.40
Total Sales Volumes (MBOE/d)	50.1	9.4	12.6	72.1

(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.

Revenues

Asia Pacific

In China, the Liwan gas project includes working interests of 49 percent in natural gas developments at the Liwan 3-1 and Lihua 34-2 producing fields and 75 percent in the Lihua 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. Block 15/33 contains an existing discovery that was drilled in 2018. We also plan to drill an exploration commitment well in Block 23/07 in 2022.

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 licence area. This area includes the operating BD field, and ongoing developments at the MDA, MBH and MDK fields. A final investment decision was made by HCML for development of the MAC field with production expected by mid-2023. During the third quarter of 2021 we were awarded the Liman license area, with exploration expected to occur over the next few years. A production sharing contract is expected to be signed in the fourth quarter of 2021.

We also hold exploration rights in a block located southwest of the island of Taiwan in the South China Sea.

Financial Results

(\$ millions)	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
Gross Sales	336	965
Less: Royalties	20	53
Revenues	316	912
Expenses		
Operating	28	74
Operating Margin	288	838

Operating Results

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
Total Sales Volumes ⁽¹⁾⁽²⁾⁽³⁾ (MBOE/d)	59.8	59.5
NGLs ⁽¹⁾⁽²⁾⁽³⁾ (Mbbbls/d)	12.7	12.6
Conventional Natural Gas ⁽¹⁾⁽²⁾⁽³⁾ (MMcf/d)	282.8	281.4
Total Realized Price per Unit Sold ⁽³⁾ (\$/BOE)	71.99	69.36
NGLs ⁽³⁾ (\$/bbl)	81.82	74.73
Conventional Natural Gas ⁽³⁾ (\$/Mcf)	11.56	11.32
Effective Royalty Rate ⁽³⁾ (percent)	8.0	6.9
Per Unit Operating Cost ⁽³⁾ (\$/BOE)	6.49	5.73

(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.

Revenues

Price

The price we receive for natural gas 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 the third quarter, daily production was relatively flat compared with the first six months of 2021 due to increased production in Indonesia driven by high demand, offset by planned maintenance in China.

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 the three and nine months ended September 30, 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 contains the Hibernia, Terra Nova and Hebron fields, 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 the first nine months of 2021 is 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, which is being preserved quayside, will proceed. Production is expected to resume in 2022.

The West White Rose Project remains deferred while we continue to evaluate options with our partners. In the third quarter, Cenovus entered into an agreement with Suncor Energy Inc. to decrease our working interest in the White Rose field and satellite extensions, contingent upon approval of the West White Rose project restarting. Cenovus would reduce its working interest in the original field from 72.5 percent to 60.0 percent and in the satellite extensions from 68.9 percent to 56.4 percent. The decision for the West White Rose project is expected to be made by mid-2022.

Financial Results

(\$ millions)	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
Gross Sales	68	297
Less: Royalties	4	21
Revenues	64	276
Expenses		
Transportation	3	10
Operating	21	92
Operating Margin	40	174

Operating Results

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
Total Sales Volumes		
Light Crude Oil (Mbbbls/d)	7.8	12.6
Total Realized Price per Unit Sold (\$/bbl)		
Light Crude Oil (\$/bbl)	94.26	85.93
Total Daily Production		
Light Crude Oil (Mbbbls/d)	13.9	15.3
Effective Royalty Rate (percent)	5.9	7.0
Per Unit Operating Cost (\$/bbl)	29.44	26.62

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 decreased compared with the first six months of 2021 due to minor planned outages and a 15-day planned maintenance on the SeaRose floating production storage 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 7.8 thousand barrels per day and 12.6 thousand barrels per day in the three and nine months ended September 30, 2021, respectively.

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 the three and nine months ended September 30, 2021, were repairs and maintenance, workforce, vessel costs, and helicopter costs. Total operating expenses decreased compared with the first and second quarters of 2021 due to lower sales volumes.

Transportation

Transportation includes the cost of transporting 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 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 and bitumen into asphalt products used in road construction and maintenance. The refinery also produces straight run gasoline, bulk distillates and industrial products. The Lloydminster Refinery has crude oil throughput capacity of 29.0 thousand barrels per day.
- Two 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 production.

In the third quarter of 2021 we:

- Delivered safe and reliable operations.
- Averaged combined crude utilization of 98 percent at the Lloydminster Upgrader and Lloydminster Refinery.
- Achieved record single-day diesel production at the Lloydminster Upgrader.
- Generated Operating Margin of \$130 million, an increase of \$123 million compared with 2020 due to assets acquired in the Arrangement.

Financial Results

(\$ millions)	Three Months Ended September 30,		Nine Month Ended September 30,	
	2021	2020	2021	2020
Revenues	1,215	15	3,109	58
Purchased Product	986	—	2,424	—
Gross Margin	229	15	685	58
Expenses				
Operating	99	8	284	29
Operating Margin	130	7	401	29
Depreciation, Depletion and Amortization	41	2	127	6
Segment Income (Loss)	89	5	274	23

Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Crude Oil Throughput Capacity (Mbbbls/d)	110.5	—	110.5	—
Lloydminster Upgrader (Mbbbls/d)	81.5	—	81.5	—
Lloydminster Refinery (Mbbbls/d)	29.0	—	29.0	—
Crude Oil Throughput (Mbbbls/d)	108.3	—	106.0	—
Lloydminster Upgrader (Mbbbls/d)	81.2	—	78.6	—
Lloydminster Refinery (Mbbbls/d)	27.1	—	27.4	—
Crude Utilization ⁽¹⁾ (percent)	98	—	96	—
Refined Products Output (Mbbbls/d)	109	—	107	—
Upgrading Differential ⁽²⁾	17.00	—	15.84	—
Refining Margin (\$/bbl)				
Lloydminster Upgrader (\$/bbl)	16.93	—	16.91	—
Lloydminster Refinery (\$/bbl)	19.29	—	16.58	—
Operating Expense ⁽³⁾ (\$/bbl)	9.83	—	9.81	—
Crude-by-Rail Operations				
Volumes Loaded ⁽⁴⁾ (Mbbbls/d)	14.3	—	13.0	33.8
Ethanol Production (thousands of litres/d)	774.0	—	607.4	—

(1) Based on crude throughput volumes and results of operations at the Lloydminster Upgrader and Refinery.

(2) Based on benchmark price differentials between heavy oil feedstock and synthetic crude.

(3) Operating costs over crude throughput.

(4) Volumes loaded and transported outside of Alberta.

Gross Margin

Upgrading operations process heavy crude oil into high value synthetic crude oil and low sulphur distillates. Upgrading profitability 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 heavy crude oil into asphalt and industrial products. The gross margin is primarily dependent on market prices for asphalt and other industrial products 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. Gross margin at the Lloydminster Refinery increased compared with the first and second quarters due to a full quarter of paving season.

In the third quarter, gross margin at the Lloydminster Upgrader was comparable with the second quarter of 2021 as throughput and the upgrading differential increased marginally.

For the nine months ended September 30, 2021, revenue includes approximately \$55 million for a customer settlement of a take-or-pay contract in the second quarter related to Bruderheim crude-by-rail terminal operations.

Operating Expense

Primary drivers of operating expenses for the three and nine months ended September 30, 2021, were workforce, repairs and maintenance, and energy costs. For the three and nine months ended September 30, 2021, unit operating expenses were \$9.83 per barrel of crude throughput and \$9.81 per barrel of crude throughput, respectively.

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 three and nine months ended September 30, 2021, Canadian Manufacturing DD&A was \$41 million and \$127 million, respectively (2020 – \$2 million and \$6 million, respectively) as a result of assets acquired as part of the Arrangement.

U.S. MANUFACTURING

On December 31, 2020, U.S. Manufacturing operations included the Wood River and Borger refineries jointly owned with operator Phillips 66. We have a 50 percent interest in WRB Refining LP, the owner of the refineries.

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

- The Lima Refinery, which we own 100 percent, is located in Lima, Ohio. The refinery produces low sulphur gasoline, gasoline blend stocks, ultra-low sulphur diesel, aviation fuel, petrochemical feedstock, and other by-products.
- The Toledo Refinery, of which our interest is 50 percent, is located near Toledo, Ohio. The refinery is jointly owned with operator BP. Products from the refinery include low sulphur gasoline, ultra-low sulphur diesel, aviation fuel, and other by-products.
- The Superior Refinery, of which we own 100 percent, 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 the third quarter of 2021, we:

- Delivered safe and reliable operations.
- Further increased throughput, averaging 89 percent crude utilization as market conditions improved and our assets performed well.
- Were impacted by temporary unplanned outages at the Wood River and Borger refineries, negatively affecting throughput.

Financial Results

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020 ⁽¹⁾	2021	2020 ⁽¹⁾
Revenues	5,723	1,237	13,889	3,633
Purchased Product	5,171	1,133	12,320	3,413
Gross Margin	552	104	1,569	220
Expenses				
Operating	413	179	1,212	564
Realized (Gain) Loss on Risk Management	17	2	48	(6)
Operating Margin	122	(77)	309	(338)
Unrealized (Gain) Loss on Risk Management ⁽²⁾	5	(3)	38	(1)
Depreciation, Depletion and Amortization	103	518	320	666
Segment Income (Loss)	14	(592)	(49)	(1,003)

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

⁽²⁾ Unrealized gain and loss on risk management are 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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Crude Oil Throughput Capacity (Mbbbls/d)	502.5	247.5	502.5	247.5
Wood River and Borger Refineries ⁽¹⁾	247.5	247.5	247.5	247.5
Lima Refinery	175.0	—	175.0	—
Toledo Refinery ⁽¹⁾	80.0	—	80.0	—
Crude Oil Throughput (Mbbbls/d)	445.8	191.1	415.0	191.5
Wood River and Borger Refineries ⁽¹⁾	211.7	191.1	197.1	191.5
Lima Refinery	163.1	—	149.6	—
Toledo Refinery ⁽¹⁾	71.0	—	68.3	—
Throughput by Product (Mbbbls/d)				
Heavy Crude Oil	143.8	76.9	133.0	77.1
Light and Medium Crude Oil	302.0	114.2	282.0	114.4
Crude Utilization (percent)	89	77	83	77
Refining Margin ⁽²⁾ (\$/bbl)	13.45	5.91	13.84	4.22
Operating Expense ⁽²⁾ (\$/bbl)	10.03	10.18	10.69	10.76

(1) Represents Cenovus's 50 percent interest in Wood River, Borger and Toledo refinery operations.

(2) Based on crude oil throughput volumes and operating results at Wood River, Borger, Lima and Toledo refineries.

All refineries continue to optimize throughput as market conditions dictate. Throughput ran at reduced rates early in the first quarter due to low market crack spreads and in the second and third quarters due to planned and unplanned outages.

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 during the second and third quarters.

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 which 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 at the Mid-Valley and West Texas Gulf pipelines which reduced throughput. Throughput rates increased in late May and June after completion of the maintenance. We achieved a utilization rate of 93 percent in the third quarter as the Lima Refinery performed very well. Production slowed at the end of September as we prepared for a planned turnaround to be completed in the fourth quarter.

At the Toledo Refinery, throughput was optimized in line with market demand in the first nine months of 2021.

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 the third quarter of 2021, gross margin increased \$448 million compared with the third quarter of 2020, primarily due to higher crude throughput and market crack spreads. The increase was partially offset by higher RINs costs and lower margins on fixed price products due to higher benchmark WTI.

In the first nine months of 2021, gross margin increased \$1.3 billion compared with 2020 driven by improved market crack spreads combined with increased throughput, partially offset by higher RINs costs and lower margins on clean and fixed price products.

Gross margin further improved in the three and nine months ended September 30, 2021 as a result of additional crude throughput and sales volumes from assets acquired in the Arrangement.

In the three and nine months ended September 30, 2021, the cost of RINs was \$248 million and \$733 million, respectively (2020 – \$50 million and \$119 million, respectively) due to higher RINs pricing and assets acquired in the Arrangement. RINs prices were US\$7.32 per barrel and US\$6.97 per barrel in the three and nine months ended 2021,

respectively (2020 –US\$2.64 per barrel and US\$2.14 per barrel, respectively). RINs pricing was volatile in the first nine months of the year, ranging from slightly over US\$4.00 per barrel to almost US\$10.00 per barrel.

Operating Expenses

Primary drivers of operating expenses for the three and nine months ended September 30, 2021, were repairs and maintenance, workforce costs, and utilities. In the third quarter of 2021, operating expenses increased \$234 million compared with the third quarter of 2020 due to assets acquired in the Arrangement.

In the first nine months of 2021, operating costs increased \$648 million year-over-year. The increase was due to:

- Assets acquired in the Arrangement.
- Turnaround activities at Wood River and Borger refineries.
- Higher utility pricing at the Lima and Borger refineries associated with the impacts of winter storm Uri in the first quarter of 2021.
- Preparation for the planned turnaround at the Lima Refinery in the fourth 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 \$103 million and \$320 million in the three and nine months ended September 30, 2021, respectively (2020 – \$518 million and \$666 million, respectively). The decrease is the result of an impairment charge of \$450 million related to the Borger CGU in the third quarter of 2020, partially offset by assets acquired in the Arrangement.

RETAIL

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

For the three and nine months ended September 30, 2021, our retail and commercial network averaged 527 and 534 independently operated Husky and Esso branded petroleum product outlets, respectively. 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.

Financial Results

(\$ millions)	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
Gross Sales	592	1,540
Purchased Product	551	1,434
Gross Margin	41	106
Expenses		
Operating	25	73
Operating Margin	16	33
Depreciation, Depletion and Amortization	11	36
Segment Income (Loss)	5	(3)

Select Operating Results

	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2021
Fuel Sales Volume, including wholesale		
Fuel Sales (millions of litres/d)	7.3	6.9
Fuel Sales per Retail Outlet (thousands of litres/d)	13.9	12.8

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 three and nine months ended September 30, 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 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 three and nine months ended September 30, 2021, Retail DD&A was \$11 million and \$36 million, respectively, as a result of retail assets acquired in the Arrangement.

CORPORATE AND ELIMINATIONS

In the nine months ended September 30, 2021, our corporate risk management activities resulted in realized risk management losses of \$91 million (2020 – losses of \$4 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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(\$ millions)	2021	2020	2021	2020
General and Administrative ⁽¹⁾	158	51	491	124
Finance Costs	360	145	836	391
Interest Income	(4)	(2)	(11)	(4)
Integration Costs	45	—	302	—
Foreign Exchange (Gain) Loss, Net	196	(159)	(93)	168
Re-measurement of Contingent Payment	135	(31)	571	(97)
(Gain) Loss on Divestiture of Assets	(25)	(1)	(97)	—
Other (Income) Loss, Net ⁽²⁾	(107)	(14)	(208)	(52)
	<u>758</u>	<u>(11)</u>	<u>1,791</u>	<u>530</u>

(1) Onerous contract provisions of \$1 million and \$4 million in the three and nine months ended September 30, 2020, respectively, have been reclassified to general and administrative expenses.

(2) Research costs of \$3 million and \$8 million in the three and nine months ended September 30, 2020, respectively, have been reclassified to other (income) loss, net.

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. In the three and nine months ended September 30, 2021, general and administrative expenses increased year-over-year due to a larger workforce resulting from the Arrangement. In addition, for the three and nine months ended September 30, 2021, long-term incentive costs were higher than the same period in 2020 due to share price increases compared with share price decreases in 2020.

Finance Costs

In the three and nine months ended September 30, 2021, finance costs increased by \$215 million and \$445 million, respectively, due to interest expense on long-term debt assumed as part of the Arrangement. In addition, finance costs include a \$115 million net premium on the redemption of long-term debt in the third quarter of 2021. Also contributing to the increase are the unwinding of the discount on decommissioning liabilities, and 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 three and nine months ended September 30, 2021, was 4.7 percent and 4.6 percent, respectively (three and nine months ended September 30, 2020 – 4.8 percent).

Integration Costs

For the three and nine months ended September 30, 2021, we incurred \$45 million and \$302 million, respectively, of costs as a result of the Arrangement, not including capital expenditures. Integration costs included \$171 million of severance payments, \$65 million of transaction costs, and \$66 million in other integration related costs for the first nine months of 2021.

Foreign Exchange

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Unrealized Foreign Exchange (Gain) Loss	111	(140)	(220)	229
Realized Foreign Exchange (Gain) Loss	85	(19)	127	(61)
	196	(159)	(93)	168

In the third quarter of 2021 and on a year-to-date basis, unrealized foreign exchange losses of \$111 million and gains of \$220 million, respectively, were mainly as a result of the translation of our U.S. dollar denominated debt. In the three and nine months ended September 30, 2021, realized foreign exchange losses of \$85 million and \$127 million, respectively, were recorded primarily due to the recognition of a \$139 million loss on the repurchase of U.S. dollar denominated debt in the third quarter.

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, (the "Acquisition in 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 contingent payment is accounted for as a financial option. The fair value of \$392 million as at September 30, 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 three and nine months ended September 30, 2021, non-cash re-measurement losses of \$135 million and \$571 million, respectively, were recorded. As at September 30, 2021, \$119 million is payable under this agreement. For the three months ended September 30, 2021, we paid \$90 million under this agreement, of which \$56 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 \$77.66 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately \$75.57 per barrel and \$79.73 per barrel.

Other (Income) Loss, Net

For the three and nine months ended September 30, 2021, other (income) loss increased by \$93 million and \$156 million, respectively. The increase in the third quarter is primarily due to a settlement of a legal claim in favour of Cenovus. For the three and nine months ended September 30, 2021, business interruption insurance proceeds related to the Superior Refinery was \$nil and \$45 million, respectively. The revaluation gain on the Headwater warrants resulted in other income of \$2 million for the third quarter and \$27 million year-to-date.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements, office furniture and certain ROU assets. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. ROU assets are depreciated on a straight-line basis over the estimated useful life of the asset or the lease term. DD&A in the three and nine months ended September 30, 2021, was \$29 million and \$91 million, respectively (2020 – \$27 million and \$104 million, respectively). The decrease in DD&A for the nine months ended September 30, 2021, was primarily due to an impairment loss of \$8 million related to leasehold improvements in 2020.

Income Tax

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Current Tax				
Canada	58	(1)	72	(3)
United States	—	—	—	1
Asia Pacific	34	—	115	—
Other International	—	—	1	—
Current Tax Expense (Recovery)	92	(1)	188	(2)
Deferred Tax Expense (Recovery)	191	(177)	281	(656)
Total Tax Expense (Recovery)	283	(178)	469	(658)

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

For the three and nine months ended September 30, 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 the third quarter of 2020.

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.

LIQUIDITY AND CAPITAL RESOURCES

(\$ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2021	2020	2021	2020
Cash From (Used In)				
Operating Activities	2,138	732	3,735	23
Investing Activities	(327)	(136)	(547)	(663)
Net Cash Provided (Used) Before Financing Activities	1,811	596	3,188	(640)
Financing Activities	(913)	(322)	(1,591)	901
Equivalents Held in Foreign Currency	57	(22)	35	(43)
Increase (Decrease) in Cash and Cash Equivalents	955	252	1,632	218
			September 30,	December 31,
			2021	2020
Cash and Cash Equivalents			2,010	378
Debt ⁽¹⁾			13,034	7,562

(1) Includes long-term debt and short-term borrowings. On January 1, 2021, on the closing of the Arrangement, we acquired cash and cash equivalents of \$735 million and debt of \$6.6 billion.

Cash From (Used in) Operating Activities

For the three and nine months ended September 30, 2021, cash generated from operating activities increased compared with 2020 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, our working capital was \$2.8 billion at September 30, 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 accrued revenues and inventories, partially offset by increased accounts payable and accrued liabilities and the current portion of long-term debt.

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 higher in the three months ended September 30, 2021, compared with 2020 primarily due to higher capital spending, partially offset by proceeds from divestitures and net cash received on assumption of decommissioning liabilities on the restructuring of our working interests in the Terra Nova field.

Cash used in investing activities was lower in the nine months ended September 30, 2021, compared with 2020 primarily due to cash acquired through the Arrangement and proceeds from divestitures, 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 third quarter of 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\$1.8 billion to repurchase a portion of our unsecured notes with a principal amount of US\$1.7 billion. In addition, we repaid \$19 million in short term borrowings.

During the first nine months of 2021, we repaid \$108 million in short-term borrowings and \$350 million of revolving long-term debt. In the first nine months of 2020, we paid US\$81 million to repurchase a portion of our unsecured notes with a principal amount of US\$100 million.

Total Debt

Total debt, including short-term borrowings, as at September 30, 2021, was \$13.0 billion (December 31, 2020 – \$7.6 billion). The increase in total debt was mainly due to the assumption of debt at closing of the Arrangement on January 1, 2021, with a fair value of \$6.6 billion. The principal amount of debt assumed from Husky that is owed to lenders between 2022 and 2037 is \$4.9 billion. We have reduced our total debt by \$1.2 billion since the closing of the Arrangement as described in the cash used in financing activities above.

As at September 30, 2021, we were in compliance with all of the terms of our debt agreements.

On October 20, 2021, the Company paid US\$433 million and redeemed the remaining outstanding principal amount of US\$425 million of its 3.95 percent notes due April 15, 2022, and its 3.00 percent notes due August 15, 2022, resulting in a premium on the redemption of \$6 million. After this redemption, 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.

Common Share Dividends

In the third quarter of 2021, we paid dividends of \$35 million or \$0.0175 per common share (2020 – \$nil).

In the first nine months of 2021, we paid dividends of \$106 million or \$0.0525 per common share (2020 – \$77 million or \$0.0625 per common share). The declaration of dividends is at the sole discretion of the Company's Board of Directors and is considered quarterly.

Cumulative Redeemable Preferred Share Dividends

In the three and nine months ended September 30, 2021, dividends of \$9 million and \$26 million, respectively, 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 the Company's Board of Directors and is considered quarterly.

Available Sources of Liquidity

The following sources of liquidity are available at September 30, 2021:

(\$ millions)	Term	Amount Available
Cash and Cash Equivalents	Not applicable	2,010
Committed Credit Facilities		
\$6.0 Billion Revolving Credit Facility – Tranche A	August 2025	4,000
\$6.0 Billion Revolving Credit Facility – Tranche B	August 2024	2,000
Uncommitted Demand Facilities		
Cenovus Energy Inc.	Not applicable	1,019
WRB Refining LP (Cenovus's proportionate share)	Not applicable	143
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 the quarter, 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

On August 18, 2021, the \$8.5 billion of committed credit facilities, which included those assumed in the Arrangement, were cancelled and replaced with a \$6.0 billion committed revolving credit facility. The committed revolving credit facility consists of a \$2.0 billion tranche maturing on August 18, 2024, and a \$4.0 billion tranche maturing on August 18, 2025.

Uncommitted Demand Facilities

We have uncommitted demand facilities of \$2.4 billion in place, of which \$1.3 billion may be drawn for general purposes or the full amount can be available to issue letters of credit. As at September 30, 2021, there were no amounts drawn on these facilities (December 31, 2020 – \$nil) and there were outstanding letters of credit aggregating to \$507 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 September 30, 2021, US\$75 million was drawn on these facilities, of which US\$38 million (\$48 million) was our proportionate share (December 31, 2020 – \$121 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 at September 30, 2021 (December 31, 2020 – \$nil).

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

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.

In September 2021, the Company paid US\$1.8 billion to repurchase a portion of its unsecured notes with a principal amount of US\$1.7 billion. A net premium on redemption of \$115 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\$254 million.
- 3.00 percent unsecured notes due 2022 – US\$321 million.
- 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.

On October 20, 2021, the Company redeemed the remaining outstanding principal of US\$425 million of its 3.95 percent notes due April 15, 2022, and its 3.00 percent notes due August 15, 2022.

Base Shelf Prospectus

As at September 30, 2021, US\$2.4 billion remained available under the since replaced base shelf prospectus for permitted offerings. On October 7, 2021, we filed our 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 and replaces our US\$5.0 billion base shelf prospectus, which expired in October 2021.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Net Debt to Adjusted EBITDA and Net Debt to Capitalization. We define our non-GAAP measure of Net Debt as short-term borrowings, and the current and long-term portions of long-term debt, net of cash and cash equivalents and short-term investments. We define Capitalization as Net Debt plus Equity. We define Adjusted EBITDA as net earnings before finance costs, interest income, income tax expense (recovery), DD&A, exploration expense, goodwill impairments, asset impairments and reversals, unrealized gains (losses) on risk management, foreign exchange gains (losses), revaluation

gain, re-measurement of contingent payment, gains (losses) on divestiture of assets, other income (loss), net, and share of income (loss) from equity-accounted investees calculated on a trailing 12-month basis. These measures are used to steward our overall debt position and as measures of our overall financial strength.

	September 30, 2021	December 31, 2020
Net Debt to Capitalization ⁽¹⁾ (percent)	31	30
Net Debt to Adjusted EBITDA (times)	1.7x	11.9x

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

We target a Net Debt to Adjusted EBITDA ratio of less than 2.0 times. This ratio may periodically be above the target due to factors such as persistently low commodity prices. Our objective is to maintain a high level of capital discipline and manage our capital structure to help ensure 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, repurchase our common shares for cancellation, issue new debt, or issue new shares.

On December 31, 2020, before the Arrangement, our Net Debt to Capitalization was 30 percent. Our Net Debt to Capitalization increased to 36 percent on March 31, 2021, primarily due to Net Debt assumed from the Arrangement. We reduced our Net Debt to Capitalization to 34 percent at June 30, 2021 and we further reduced our Net Debt to Capitalization by three percent to 31 percent at September 30, 2021. Reductions in this measure are due to our continued efforts to reduce Net Debt as described in the Cash From (Used In) Financing Activities above.

As at September 30, 2021, our Net Debt to Adjusted EBITDA was 1.7 times. Net Debt to Adjusted EBITDA decreased compared with the fourth quarter of 2020 as a result of higher Operating Margin in the first nine months of 2021, 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 interim 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 common share purchase 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 September 30, 2021, there were approximately 2,018 million common shares outstanding (December 31, 2020 — 1,229 million common shares). Refer to Note 22 of the interim Consolidated Financial Statements for more details.

Refer to Note 24 of the interim 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 October 27, 2021	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares ⁽¹⁾	2,017,676	N/A
Common Share Warrants	65,179	N/A
Preferred Shares Series 1	10,740	N/A
Preferred Shares Series 2	1,260	N/A
Preferred Shares Series 3	10,000	N/A
Preferred Shares Series 5	8,000	N/A
Preferred Shares Series 7	6,000	N/A
Stock Options ⁽¹⁾	40,511	26,245
Other Stock-Based Compensation Plans	14,728	1,397

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

Capital Investment Decisions

Our 2021 capital program is forecast to be between \$2.3 billion and \$2.7 billion. Our investment is focused on maintaining safe and reliable operations, while positioning the Company to drive enhanced shareholder value that includes sustaining capital of approximately \$2.1 billion to deliver upstream production of approximately 770.0 thousand BOE per day and downstream throughput of approximately 525.0 thousand barrels per day.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(\$ millions)	2021	2020	2021	2020
Adjusted Funds Flow	2,342	407	5,300	(216)
Total Capital Investment	647	148	1,728	599
Free Funds Flow ⁽¹⁾	1,695	259	3,572	(815)
Cash Dividends	44	—	132	77
	1,651	259	3,440	(892)

⁽¹⁾ Free Funds Flow is a non-GAAP measure defined as Adjusted Funds Flow less capital investment.

Our approach on the financial framework remains consistent with the parameters we have set for Cenovus in prior years. 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 balance our Free Funds Flow towards debt reduction and increasing shareholder returns. We continue to target a Net Debt to Adjusted EBITDA ratio of less than 2.0 times.

We remain committed to investment-grade credit ratings and strengthening our ratings from current levels. This includes our continued focus on allocating Free Funds Flow to reduce Net Debt to less than \$10 billion and targeting a longer-term Net Debt level at or below \$8 billion. The Adjusted Funds Flow is expected to fully fund sustaining capital and shareholder distributions going forward once one-time integration costs associated with the Arrangement are complete.

Contractual Obligations and Commitments

We have obligations for goods and services entered into in the normal course of business. Obligations are primarily related to transportation agreements, our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. Obligations that have original maturities of less than one year are excluded. For further information, see the notes to the September 30, 2021, interim Consolidated Financial Statements and December 31, 2020, 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.

Our total commitments were \$33.3 billion as at September 30, 2021, of which \$29.4 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 September 30, 2021, include \$2.7 billion related to transportation, storage and other long-term contracts.

We continue to focus on mid-term strategies to broaden market access for our crude oil production including supporting proposed pipeline projects to transport our production to new markets in the U.S. and globally, as well as moving our crude oil production to market by rail. We continue to assess all options to maximize the value of our crude oil.

As at September 30, 2021, outstanding letters of credit issued as security for performance under certain contracts totaled \$507 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.

Contingent Payment

In connection with the Acquisition in 2017 and related to a portion of our oil sands production, we agreed to make quarterly payments to ConocoPhillips during the five years subsequent to May 17, 2017, for quarters in which the average WCS crude oil price exceeds \$52.00 per barrel during the quarter. As at September 30, 2021, the estimated fair value of the contingent payment was \$392 million. As at September 30, 2021, \$119 million was payable under the agreement. See the Corporate and Eliminations section of this MD&A for more details.

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 three and nine months ended September 30, 2021, we charged HMLP \$101 million and \$165 million, respectively, 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 three and nine months ended September 30, 2021, we incurred costs of \$70 million and \$215 million, respectively, for the use of HMLP's pipeline systems, as well as transportation and storage services.

RISK MANAGEMENT AND RISK FACTORS

For a full understanding of the risks that impact us, the following discussion should be read in conjunction with the Risk Management and Risk Factors section of our 2020 annual MD&A.

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

The following provides an update on our risks.

Financial Risk

Commodity Prices

Fluctuations in commodity prices, associated price differentials and refining margins impact our financial condition, results of operations, cash flows, growth, access to capital and cost of borrowing. We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts, market access commitments and generally through our access to committed credit facilities. In certain instances, Cenovus will use derivative instruments to manage exposure to price volatility on a portion of its refined product, crude oil and natural 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 26 and 27 to the interim Consolidated Financial Statements.

Risks Associated with Derivative Financial Instruments

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

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

Impact of Financial Risk Management Activities

Cenovus makes storage and transportation decisions using our marketing and transportation infrastructure, including storage and pipeline assets to optimize product mix, delivery points, transportation commitments and customer diversification. 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, 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 three and nine months ended September 30, 2021, we incurred a realized risk management loss due to the settlement of benchmark prices relative to our risk management contract prices; the underlying physical inventory sold in the periods recognized a gain due to rising benchmark prices. In the three and nine months ended September 30, 2021, unrealized gains and unrealized losses, respectively, were recorded on our crude oil financial instruments primarily due to forward benchmark pricing falling below and rising above, respectively, our risk management contract prices that related to future periods and the realization of settled positions. In a rising commodity price environment, we would expect to realize losses on our risk management activities but recognize gains on the underlying physical inventory sold in the period and the opposite to occur in a falling commodity price environment.

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 and Key Sources of Estimation Uncertainty

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in our annual and interim Consolidated Financial Statements. A full list of the key sources of estimation uncertainty can be found in our annual Consolidated Financial Statements for the year ended December 31, 2020. In 2021, the Company made updates to its critical judgments in applying accounting policies and key sources of estimation uncertainty including the assessment of joint arrangements, recoveries from insurance claims, functional currency for the Company's subsidiaries and the fair value of related party transactions. Updates to critical judgments and key sources of estimation relate to changes in the operations of the Company as a result of the close of the Arrangement. Further information can be found in Note 3 to the interim Consolidated Financial Statements.

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. Further information can be found in Note 3 to the interim Consolidated Financial Statements.

New Accounting Standards and Interpretations not yet Adopted

There are new standards, amendments to accounting standards and interpretations that are effective for annual periods beginning on or after January 1, 2021. There were no new or amended accounting standards or interpretations issued during the nine months ended September 30, 2021, that are expected to have a material impact on our interim 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 internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at September 30, 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 internal control over financial reporting. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at September 30, 2021.

On January 1, 2021, Cenovus and Husky closed the Arrangement to combine the two companies. As permitted by and in accordance with, National Instrument 52-109, *"Certification of Disclosure in Issuers' Annual and Interim Filings"*, and guidance issued by the U.S. Securities and Exchange Commission, Management has limited the scope and design of ICFR and DC&P to exclude the controls, policies and procedures in respect of the business acquired from Husky. Such scope limitation is primarily due to the time required for Management to assess the ICFR and DC&P relating to Husky in a manner consistent with our other operations. Further integration will take place throughout the remainder of the year as processes and systems align.

Assets attributable to Husky as at September 30, 2021, represented approximately 35 percent of Cenovus's total assets. Revenues attributable to Husky for the three and nine months ended September 30, 2021 represented approximately 50 percent of Cenovus's total revenues.

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 healthy demand growth for crude oil and refined products, while the supply response has lagged. However, the scale of resurgence and variants of COVID-19 cases is unpredictable and likely to result in crude oil and refined products market volatility through the remainder of the year and into 2022. OPEC+ policy continues to support balancing the market. The group began to gradually unwind supply curtailments and will continue to increase production through the remainder of the year and into 2022.

Our focus remains on maintaining the strength of our balance sheet. We have ample liquidity, high quality assets which we are able to effectively manage to respond to price signals, some of the lowest cost structures in the industry and have demonstrated our ability to reduce discretionary capital, all of which should allow us to continue to adapt to potential ongoing market volatility.

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. We expect our annual upstream production to average between 750.0 thousand BOE per day and 790.0 thousand BOE per day and total downstream crude throughput of 500.0 thousand barrels per day to 550.0 thousand barrels per day in 2021.

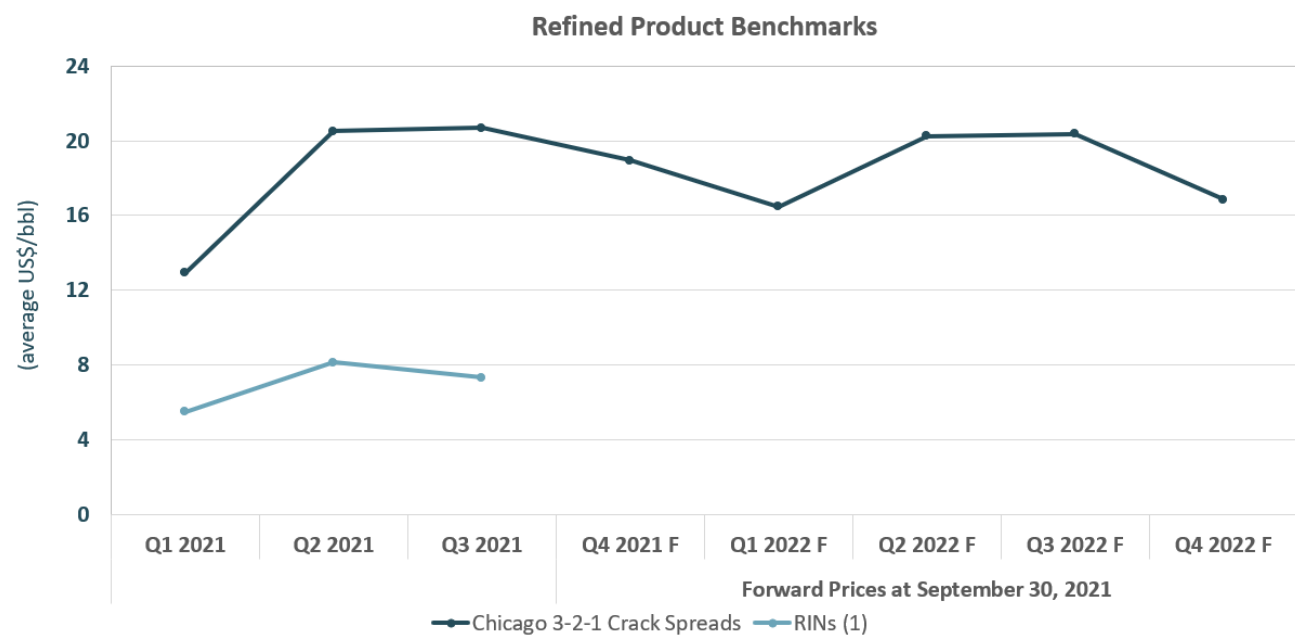
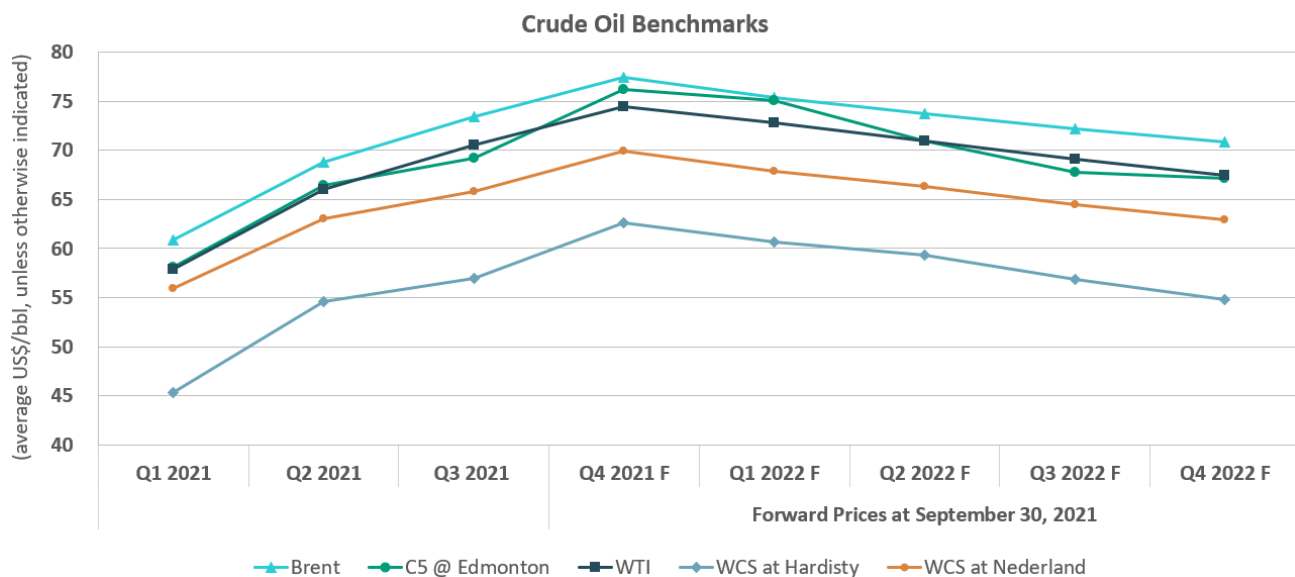
We are on target to deliver over \$1.0 billion of realized synergies this year and to reach our planned total of \$1.2 billion annual run-rate synergies by the end of 2021. Over the longer-term, we anticipate additional cost savings and margin enhancements based on further physical integration of upstream 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 additional opportunities to reduce operating, capital, and general and administrative spending and increase our margins through strong operating performance and cost leadership while focusing on safe and reliable operations.

The following outlook commentary is focused on the next 15 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, the impact of oversupply, global demand impacts amid COVID-19 concerns, and effectiveness and successful distribution of COVID-19 vaccines.
- The degree to which OPEC+ members (including Russia) continue to maintain crude oil production cuts and the rate they decide to increase production.
- 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 refining run cuts in North America.

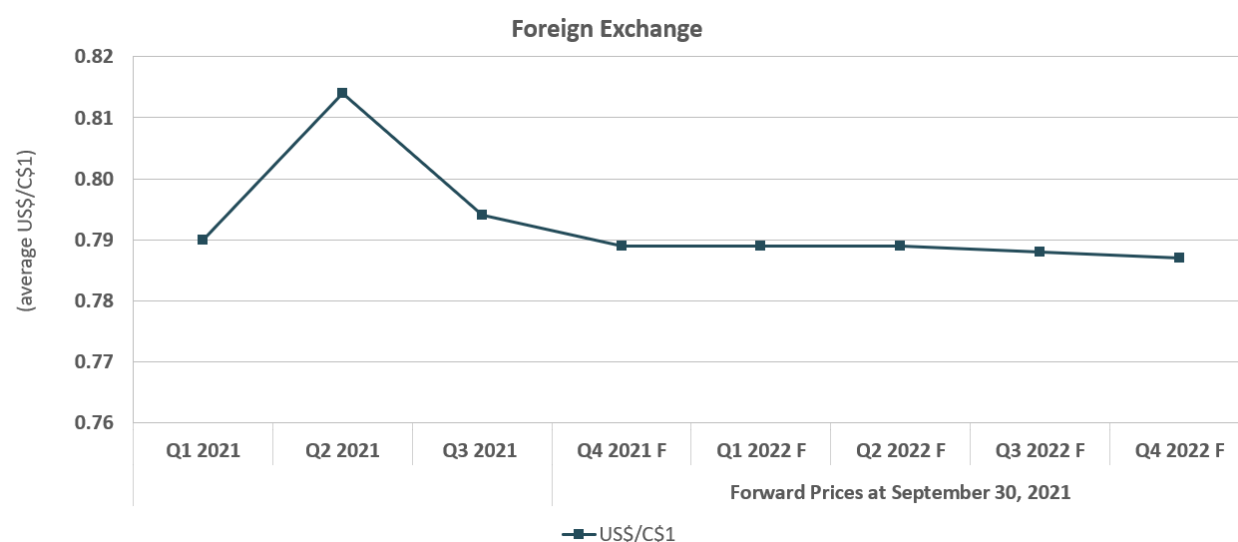
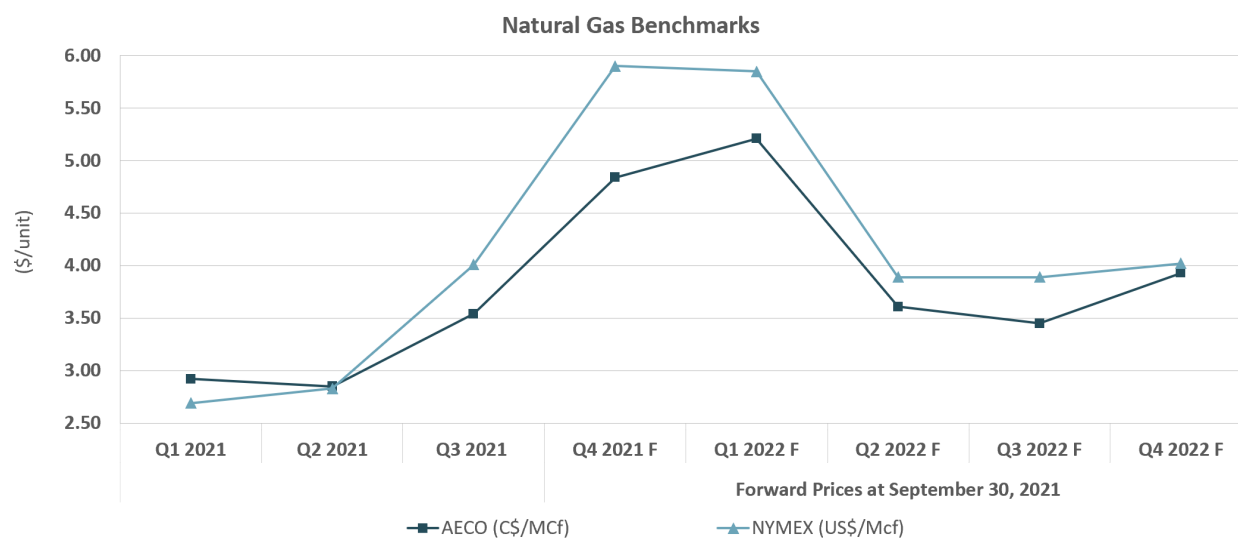


(1) RINs forward price information is unavailable after September 30, 2021.

Natural gas prices rose significantly in the third quarter of 2021 and the forward curve shows that the market expects both Henry Hub and AECO prices to continue to rise. The supply response has been muted so far, despite rebounding U.S. demand and record-high liquified natural gas exports. High global prices continue to support export demand to Europe, Asia and South America. North American fundamentals should continue to support prices for the remainder of 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 2021

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

Our corporate strategy focuses on maximizing shareholder value through cost leadership and realizing the best margins for our products. We plan to remain focused on disciplined capital investment allocation across the full suite of assets for the Company, and continue to identify opportunities to improve our cost structure and enhance margins. Furthermore, the Company prioritizes ongoing ESG leadership and integration of sustainability considerations into our business decisions.

Safe and Reliable Operations

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

Ensure Smooth Integration

In addition to financial and operating synergies, our focus is to create stability for our workforce and advance the high-performing culture of the combined Company. We aim to build an industry-leading people experience and advance leadership, commercial capability and inclusion and diversity programs. We are also working to enable continuity of business performance through practical, effective systems integration and optimization. We will refresh our vision, mission and values to reflect the Company going forward.

Capture Synergies and Maintain Cost Leadership

We are on target to deliver over \$1.0 billion of realized synergies this year and to reach our planned total of \$1.2 billion annual run-rate synergies by the end of 2021. We expect to meet these targets through the consolidation of information technology systems, eliminating other service overlaps, and through reductions to combined workforce and corporate overhead costs.

Over the longer term, we anticipate additional cost savings and margin enhancements based on further physical integration. The integration of upstream assets with the downstream and transportation, storage and logistics portfolio is expected to shorten the value chain and reduce condensate costs associated with heavy oil transportation over the longer term. We continue to look for ways to improve efficiencies across Cenovus to drive incremental capital, operating and general and administrative cost reductions.

Disciplined Capital Investment

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

Our upstream production is expected to range between 750.0 thousand BOE per day and 790.0 thousand BOE per day for 2021. Downstream throughput is expected to be in the range of 500.0 thousand barrels per day to 550.0 thousand barrels per day for 2021.

As at September 30, 2021, our Net Debt position was \$11.0 billion. Through a combination of cash on hand and available capacity on our committed credit facility and demand facilities, we have approximately \$9.2 billion of liquidity as at September 30, 2021. We will continue to focus on allocating Free Funds Flow to reduce Net Debt to less than \$10 billion and target a longer-term Net Debt level at or below \$8 billion.

Maintaining Financial Resilience

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

The Company's priority will be to maximize Free Funds Flow by focusing investments on sustaining capital expenditures which will position us to direct available Free Funds Flow to the balance sheet and allow us to achieve a Net Debt target of \$10 billion which approximates a Net Debt to Adjusted EBITDA target of less than 2.0 times at the bottom of the cycle, which we see as approximately US\$45 per barrel WTI.

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

Shareholder Returns

Since the Arrangement, we have reduced our Net Debt by \$2.1 billion to \$11.0 billion on September 30, 2021. As we approach our Net Debt target of \$10.0 billion, we are positioned to increase our allocation of Free Funds Flow towards shareholder returns.

On November 2, 2021, the Company's Board of Directors approved filing an application with the TSX for the implementation of a NCIB to purchase up to 146.5 million of the Company's common shares.

On November 2, 2021, the Company's Board of Directors declared a fourth quarter dividend of \$0.035 per common share, payable on December 31, 2021, to common shareholders of record as at December 15, 2021. This is an increase of \$0.0175 per common share compared with our dividends declared and paid in the third quarter of 2021.

Environmental, Social and Governance

We are committed to demonstrating leading ESG performance. This includes setting and achieving ambitious ESG targets, maintaining robust management systems and continuing transparent performance reporting. We will continue working to earn our position as a global energy supplier of choice by advancing clean technology and reducing emissions intensity. This includes our ambition to achieve net zero emissions by 2050. One of the steps we have taken to achieve this goal is by co-founding 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 emissions ("GHG") from oil sands operations by 2050. We will also continue building upon our strong local community relationships, with a focus on Indigenous reconciliation.

Earlier this year, we completed a robust ESG materiality assessment to identify the ESG topics that are most impactful to our new portfolio and highest priority for our stakeholders. Based on feedback from both internal and external stakeholders, climate and GHG emissions, water stewardship, biodiversity, Indigenous reconciliation and inclusion and diversity were established as our ESG focus areas. In addition, delivering safe and reliable operations and demonstrating strong governance remain foundational to how we manage our business.

In June 2021, we released our 2020 ESG data report which includes performance metrics for both Cenovus and Husky for 2020, as well as historical data for Cenovus from 2016 to 2019. Our reporting structure aligns with the Sustainability Accounting Standards Board and IPIECA, formerly known as the International Petroleum Industry Environmental Conservation Association, reporting frameworks.

As we update long-term business plans we are also working to set meaningful ESG targets, further building on the announcement of our ESG focus areas. That work is expected to be completed later this year. Once it is approved by the Board, the new targets and proposed plans to achieve them will be disclosed. Concurrently with the disclosure of our ESG targets, we plan to publish a more comprehensive 2020 ESG report, which will include the pro-forma metrics that underpin the ESG targets. This report will align with the Task Force on Climate-related Financial Disclosures as in previous years.

ADVISORY

Oil and Gas Information

Barrels of Oil Equivalent – natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six Mcf to one barrel (bbl). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil compared with natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.

Forward-looking Information

This document contains certain forward-looking statements and forward-looking information (collectively referred to as "forward-looking information") within the meaning of applicable securities legislation, including the U.S. Private Securities Litigation Reform Act of 1995, about our current expectations, estimates and projections about the future, based on certain assumptions made by us in light of our experience and perception of historical trends. Although we believe that the expectations represented by such forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Forward-looking information in this document is identified by words such as “achieve”, “aim”, “anticipate”, “believe”, “can be”, “capacity”, “committed”, “continue”, “deliver”, “drive”, “enhance”, “ensure”, “estimate”, “expect”, “focus”, “forecast”, “forward”, “future”, “guidance”, “maintain”, “may”, “objective”, “outlook”, “plan”, “position”, “priority”, “seek”, “strategy”, “should”, “target”, “will”, or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: strategy, priorities and related milestones; schedules and plans; anticipated integration costs of the Arrangement; benefits of the Arrangement, including achieving corporate, operating and capital allocation synergies and efficiencies, longer term cost savings, debt reduction and enhanced margins; fully funding sustaining capital and shareholder distributions with Adjusted Funds Flow once one-time integration costs associated with the Arrangement are complete; allocation of Free Funds Flow; growth in shareholder distributions; purchase under our NCIB; safety and safety culture; actions taken in response to COVID-19 in our workplaces; statements and expectations relating to our 2021 budget; our ability to adapt to and partially mitigate the impact of crude oil and refined product price changes and differentials; maintaining investment grade credit ratings; achieving Net Debt of less than \$10 billion and \$8 billion or lower longer-term; achieving our Net Debt to Adjusted EBITDA target; maximizing shareholder value; maximizing the value per barrel of heavy oil productions; maintaining liquidity; delivering a stable cash flow through price cycles and commodity price volatility and preserving a strong and resilient balance sheet; expected production and throughput levels; becoming a global energy supplier of choice by advancing clean technology and reducing emissions intensity; ambitions to achieve net zero emissions by 2050; plans to strengthen local community relationships, with a focus on Indigenous reconciliation; plans to set and achieve new ESG targets; evaluating disciplined investments in our portfolio against dividends, share repurchases and managing to optimal debt level while maintaining investment grade status; forecast operating and financial results, including forecast sales prices, costs and cash flows; planned capital expenditures and investments, including the amount, timing and funding sources thereof; underlying cost structures; all statements with respect to our guidance dated July 28, 2021; our ability to take steps to partially mitigate against wider WTI and WCS price differentials; funding our capital investment and near-term cash requirements through cash from operating activities and prudent use of our balance sheet capacity; focus on mid-term strategies to broaden market access for our crude oil production; preserving financial resilience; future impact of regulatory measures; forecast commodity prices, differentials and trends and expected impact; exchange and interest rates; potential impacts of various risks, including those related to commodity prices and climate change; the potential effectiveness of our risk management strategies; new accounting standards, the timing for the adoption thereof, and anticipated impact on the Consolidated Financial Statements; the immateriality of the effects of any liabilities that may arise out of legal claims associated with the normal course of our operations; the availability and repayment of our credit facilities; and expected impacts of the contingent payment to ConocoPhillips.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The factors or assumptions on which our forward-looking information is based include, but are not limited to: forecast oil and natural gas, NGLs, condensate and refined products prices, light-heavy crude oil price differentials; our ability to realize the benefits and anticipated cost synergies associated with the Arrangement; Cenovus’s ability to successfully integrate the business of Husky, including new business activities, assets, operating areas, regulatory jurisdictions, personnel and business partners for Cenovus; the accuracy of any assessments undertaken in connection with the Arrangement and any resulting pro forma information; forecast production volumes are subject to change based on business and market conditions; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; the absence of significant adverse changes to legislation and regulations, Indigenous relations, interest rates, foreign exchange rates, competitive conditions and the supply and demand for crude oil and natural gas, NGLs, condensate and refined products; the political, economic and social stability of jurisdictions in which Cenovus operates; the absence of significant disruption of operations, including as a result of harsh weather, natural disaster, accident, civil unrest or other similar events; the prevailing climatic conditions impacting Cenovus’s operating locations; achievement of further cost reductions and sustainability thereof; applicable royalty regimes, including expected royalty rates; future improvements in availability of product transportation capacity; increase to our share price and market capitalization over the long term; cash flows, cash balances on hand and access to credit and demand facilities being sufficient to fund capital investments; realization of expected capacity to store within our oil sands reservoirs barrels not yet produced, including that we will be able to time production and sales of our inventory at later dates when demand has increased, pipeline and/or storage capacity has improved and crude oil differentials have narrowed; the WTI-WCS differential in Alberta remains largely tied to the extent to which supply stays within export capacity, the completion of Trans Mountain Expansion project, and the level of crude-by-rail activity; the ability of our refining capacity, dynamic storage, existing pipeline commitments and financial hedge transactions to partially mitigate a portion of our WCS crude oil volumes against wider differentials; production declines from both associated gas and dry gas, along with rebounding U.S. demand and liquified natural gas exports should tighten North American gas fundamentals for the next 12 months and result in stronger prices than 2020 on an annual basis; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; the accuracy of accounting estimates and judgments; future use and development of technology and associated expected future results; our ability to obtain necessary regulatory and partner approvals; the successful, timely and cost effective implementation of capital projects or stages thereof; our ability to generate sufficient cash flow to meet our current and future obligations; our ability to generate Adjusted Funds Flow to fully fund sustaining capital and shareholder

distributions once one-time integration costs associated with the Arrangement are complete; the sufficiency of existing cash balances, internally generated cash flows, existing credit facilities, management of the Corporation's asset portfolio and access to capital markets to fund future development costs and dividends, including any increase thereto; ability to allocate Free Funds Flow toward shareholder returns; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; our ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; our ability to access sufficient capital to pursue our development plans; our ability to complete asset sales, including with desired transaction metrics and within the timelines we expect; the stability of general domestic and global economic, market and business conditions; forecast inflation and other assumptions inherent in Cenovus's guidance dated July 28, 2021 available on cenovus.com; our future results relative to the guidance dated July 28, 2021 based on current production volumes and operating expenses; expected impacts of, and calculation of, the contingent payment to ConocoPhillips; our ability to access and implement all technology and equipment necessary to achieve expected future results and that such results are realized; our ability to implement capital projects or stages thereof in a successful and timely manner; and other assumptions, risks and uncertainties described from time to time in the filings we make with securities regulatory authorities including the assumptions inherent in Cenovus's 2021 guidance available on cenovus.com.

The risk factors and uncertainties that could cause our actual results to differ materially from the forward-looking information, include, but are not limited to: the effect of the COVID-19 pandemic on our business, including any related restrictions, containment, and treatment measures taken by varying levels of government in the jurisdictions in which we operate; the success of our new COVID-19 workplace policies and the return of our people to our workplace; our ability to achieve the benefits and anticipated cost synergies anticipated with the Arrangement in a timely manner or at all; Cenovus's ability to successfully integrate Husky's business with its own in a timely and cost effective manner or at all; the effects of entering new business activities; unforeseen or undisclosed liabilities associated with the Arrangement; the inaccuracy of any assessments undertaken in connection with the Arrangement and any resulting pro forma information; the inaccuracy of any information provided by Husky; our ability to access or implement some or all of the technology necessary to efficiently and effectively operate our assets and achieve expected future results; the effect of Cenovus's increased indebtedness; the effect of new significant shareholders; volatility of and other assumptions regarding commodity prices; foreign exchange risk; a prolonged market downturn; changes in commodity price differentials; the effectiveness of our risk management program; the accuracy of cost estimates regarding commodity prices, currency and interest rates; lack of alignment of realized WCS prices and WCS prices used to calculate the contingent payment to ConocoPhillips; product supply and demand; the accuracy of our share price and market capitalization assumptions; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks, exposure to counterparties and partners, including the ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in the operation of our crude-by-rail terminal, including health, safety and environmental risks; our ability to maintain desirable ratios of Net Debt to Adjusted EBITDA as well as Net Debt to Capitalization; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; our ability to fund or finance growth, sustaining capital expenditures and shareholder distributions; our ability to allocate Free Funds Flow towards shareholder returns; changes in credit ratings applicable to us or any of our securities; changes to our dividend plans; our ability to utilize tax losses in the future; the accuracy of our reserves, future production and future net revenue estimates; the accuracy of our accounting estimates and judgments; our ability to replace and expand oil and gas reserves; the costs to acquire exploration rights, undertake geological studies, appraisal drilling and project developments; potential requirements under applicable accounting standards for impairment or reversal of estimated recoverable amounts of some or all of our assets or goodwill from time to time; our ability to maintain our relationships with our partners and to successfully manage and operate our integrated operations and business; reliability of our assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events resulting in operational interruptions, including blowouts, fires, explosions, railcar incidents or derailments, aviation incidents, gaseous leaks, migration of harmful substances, loss of containment, releases or spills, including releases or spills from offshore facilities and shipping vessels at terminals or hubs and as a result of pipeline or other leaks, corrosion, epidemics or pandemics, and catastrophic events, including, but not limited to, war, extreme weather events, natural disasters, iceberg incidents, acts of vandalism and terrorism, and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites and other accidents or similar events; refining and marketing margins; cost escalations, including inflationary pressures on operating costs, such as labour, materials, natural gas and other energy sources used in oil sands processes and increased insurance deductibles or premiums; the cost and availability of equipment necessary to our operations; potential failure of products to achieve or maintain acceptance in the market; risks associated with the energy industry's and Cenovus's reputation, social license to operate and litigation related thereto; unexpected cost increases or technical difficulties in operating, constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining bitumen and/or crude oil into petroleum and chemical products; risks associated with technology and equipment and its application to our business, including potential cyberattacks; geopolitical and other risks associated with our international operations; risks associated with climate change and our assumptions relating thereto; the timing and the costs of well and pipeline construction; our ability to access markets and to secure adequate and cost effective product transportation including sufficient pipeline, crude-by-rail, marine or alternate transportation, including to address any gaps caused by constraints in the pipeline system or storage capacity; availability of,

and our ability to attract and retain, critical talent; possible failure to obtain and retain qualified leadership and personnel, and equipment in a timely and cost efficient manner; changes in labour demographics and relationships, including with any unionized workforces; unexpected abandonment and reclamation costs; changes in the regulatory frameworks, permits and approvals in any of the locations in which we operate or to any of the infrastructure upon which we rely; government actions or regulatory initiatives to curtail energy operations or pursue broader climate change agendas; changes to regulatory approval processes and land-use designations, royalty, tax, environmental, greenhouse gas, carbon, climate change and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our Consolidated Financial Statements; changes in general economic, market and business conditions; the impact of production agreements among OPEC and non-OPEC members; the political, social and economic conditions in the jurisdictions in which we operate or supply; the status of our relationships with the communities in which we operate, including with Indigenous communities; the occurrence of unexpected events such as protests, pandemics, war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits, shareholder proposals and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward-looking information. For a full discussion of our material risk factors, see Risk Management and Risk Factors in this MD&A, and to the risk factors described in other documents Cenovus files from time to time with securities regulatory authorities in Canada, available on SEDAR at sedar.com, and with the U.S. Securities and Exchange Commission on EDGAR at sec.gov, and on the Corporation's website at cenovus.com. Additional information concerning Husky's business and assets as of December 31, 2020 may be found in the Husky Annual Information Form and Husky MD&A, each of which is filed and available on SEDAR under Husky's profile at sedar.com.

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

ABBREVIATIONS

The following abbreviations have been used in this document:

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

NETBACK RECONCILIATIONS

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

Total Production

Upstream Financial Results

Three Months Ended September 30, 2021 (\$ millions)	Per Interim Consolidated Financial Statements			
	Oil Sands ⁽¹⁾	Conventional ⁽¹⁾	Offshore ⁽¹⁾	Total Upstream
Gross Sales	6,114	833	404	7,351
Royalties	669	40	24	733
Purchased Product	822	445	—	1,267
Transportation and Blending	1,918	20	3	1,941
Operating	616	135	49	800
Netback	2,089	193	328	2,610
Realized (Gain) Loss on Risk Management	166	2	—	168
Operating Margin	1,923	191	328	2,442

Three Months Ended September 30, 2021 (\$ millions)	Per Interim Consolidated Financial Statements						Basis of Netback Calculation
	Total Upstream	Condensate	Third-Party Sourced	Internal Consumption ⁽²⁾	Equity Adjustment ⁽³⁾	Other ⁽⁴⁾⁽⁷⁾	
Gross Sales	7,351	(1,538)	(1,200)	(175)	60	(65)	4,433
Royalties	733	—	—	—	11	—	744
Purchased Product	1,267	—	(1,200)	—	—	(67)	—
Transportation and Blending	1,941	(1,538)	—	—	—	20	423
Operating	800	—	—	(175)	6	(13)	618
Netback	2,610	—	—	—	43	(5)	2,648
Realized (Gain) Loss on Risk Management	168	—	(2)	—	—	—	166
Operating Margin	2,442	—	2	—	43	(5)	2,482

Three Months Ended September 30, 2020 (\$ millions) ⁽⁵⁾	Per Interim Consolidated Financial Statements			
	Oil Sands ⁽¹⁾	Conventional ⁽¹⁾	Offshore ⁽¹⁾	Total Upstream
Gross Sales	2,436	232	—	2,668
Royalties	129	24	—	153
Purchased Product	235	76	—	311
Transportation and Blending	1,015	21	—	1,036
Operating	286	81	—	367
Netback	771	30	—	801
Realized (Gain) Loss on Risk Management	137	—	—	137
Operating Margin	634	30	—	664

Three Months Ended September 30, 2020 (\$ millions) ⁽⁵⁾	Per Interim Consolidated Financial Statements						Basis of Netback Calculation
	Total Upstream	Condensate	Third-party Sourced	Inventory Write-Down ⁽⁶⁾	Internal Consumption ⁽²⁾	Other ⁽⁴⁾	
Gross Sales	2,668	(747)	(317)	—	(65)	(12)	1,527
Royalties	153	—	—	—	—	—	153
Purchased Product	311	—	(317)	—	—	6	—
Transportation and Blending	1,036	(747)	—	6	—	—	295
Operating	367	—	—	—	(65)	(17)	285
Netback	801	—	—	(6)	—	(1)	794
Realized (Gain) Loss on Risk Management	137	—	—	—	—	—	137
Operating Margin	664	—	—	(6)	—	(1)	657

(1) Found in Note 1 of the Interim 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 and transportation and blending have been re-presented to reflect a change in classification of marketing activities for the first and second quarters of 2021.

Nine Months Ended September 30, 2021 (\$ millions)	Per Interim Consolidated Financial Statements			
	Oil Sands ⁽¹⁾	Conventional ⁽¹⁾	Offshore ⁽¹⁾	Total Upstream
Gross Sales	15,904	2,235	1,262	19,401
Royalties	1,462	103	74	1,639
Purchased Product	2,114	1,113	—	3,227
Transportation and Blending	5,476	57	10	5,543
Operating	1,793	417	166	2,376
Netback	5,059	545	1,012	6,616
Realized (Gain) Loss on Risk Management	584	2	—	586
Operating Margin	4,475	543	1,012	6,030

Nine Months Ended September 30, 2021 (\$ millions)	Per Interim Consolidated Financial Statements						Basis of Netback Calculation
	Total Upstream	Condensate	Third-party Sourced	Internal Consumption ⁽²⁾	Equity Adjustment ⁽³⁾	Other ⁽⁴⁾	
Gross Sales	19,401	(4,322)	(3,048)	(469)	162	(261)	11,463
Royalties	1,639	—	—	—	23	—	1,662
Purchased Product	3,227	—	(3,048)	—	—	(179)	—
Transportation and Blending	5,543	(4,322)	—	—	—	—	1,221
Operating	2,376	—	—	(469)	18	(34)	1,891
Netback	6,616	—	—	—	121	(48)	6,689
Realized (Gain) Loss on Risk Management	586	—	(2)	—	—	—	584
Operating Margin	6,030	—	2	—	121	(48)	6,105

Nine Months Ended September 30, 2020 (\$ millions) ⁽⁵⁾	Per Interim Consolidated Financial Statements			
	Oil Sands ⁽¹⁾	Conventional ⁽¹⁾	Offshore ⁽¹⁾	Total Upstream
Gross Sales	6,117	636	—	6,753
Royalties	200	28	—	228
Purchased Product	806	184	—	990
Transportation and Blending	3,552	63	—	3,615
Operating	839	248	—	1,087
Netback	720	113	—	833
Realized (Gain) Loss on Risk Management	228	—	—	228
Operating Margin	492	113	—	605

Nine Months Ended September 30, 2020 (\$ millions) ⁽⁵⁾	Per Interim Consolidated Financial Statements						Basis of Netback Calculation
	Total Upstream	Condensate	Third-party Sourced	Inventory Write-Down ⁽⁶⁾	Internal Consumption ⁽²⁾	Other ⁽⁴⁾	
Gross Sales	6,753	(2,599)	(1,014)	—	(133)	(42)	2,965
Royalties	228	—	—	(1)	—	—	227
Purchased Product	990	—	(1,014)	—	—	24	—
Transportation and Blending	3,615	(2,599)	—	1	—	—	1,017
Operating	1,087	—	—	—	(133)	(54)	900
Netback	833	—	—	—	—	(12)	821
Realized (Gain) Loss on Risk Management	228	—	—	—	—	—	228
Operating Margin	605	—	—	—	—	(12)	593

(1) Found in Note 1 of the Interim 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) 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.

Oil Sands

Three Months Ended September 30, 2021 (\$ millions)	Basis of Netback Calculation						Total Oil Sands
	Foster Creek	Christina Lake	Sunrise ⁽⁶⁾	Other Oil Sands ⁽²⁾	Total Bitumen and Heavy Oil	Natural Gas and Medium Oil	
Gross Sales	1,325	1,405	156	872	3,758	8	3,766
Royalties	238	324	7	99	668	1	669
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	192	125	33	50	400	—	400
Operating	194	171	32	208	605	8	613
Netback	701	785	84	515	2,085	(1)	2,084
Realized (Gain) Loss on Risk Management							166
Operating Margin							1,918

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⁾⁽⁶⁾	Total Oil Sands	
Gross Sales	3,766	1,538	755	55	6,114	
Royalties	669	—	—	—	669	
Purchased Product	—	—	755	67	822	
Transportation and Blending	400	1,538	—	(20)	1,918	
Operating	613	—	—	3	616	
Netback	2,084	—	—	5	2,089	
Realized (Gain) Loss on Risk Management	166	—	—	—	166	
Operating Margin	1,918	—	—	5	1,923	

Three Months Ended September 30, 2020 (\$ millions) ⁽⁴⁾	Basis of Netback Calculation						Total Oil Sands
	Foster Creek	Christina Lake	Sunrise	Other Oil Sands ⁽²⁾	Total Bitumen and Heavy Oil	Natural Gas and Medium Oil	
Gross Sales	605	842	—	—	1,447	—	1,447
Royalties	36	93	—	—	129	—	129
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	125	149	—	—	274	—	274
Operating	131	143	—	—	274	—	274
Netback	313	457	—	—	770	—	770
Realized (Gain) Loss on Risk Management							137
Operating Margin							633

Three Months Ended September 30, 2020 (\$ millions) ⁽³⁾	Basis of Netback Calculation		Adjustments			Per Interim Consolidated Financial Statements ⁽¹⁾
	Total Oil Sands	Condensate	Third-party Sourced	Inventory Write-down ⁽⁵⁾	Other	Total Oil Sands
Gross Sales	1,447	747	241	—	1	2,436
Royalties	129	—	—	—	—	129
Purchased Product	—	—	241	—	(6)	235
Transportation and Blending	274	747	—	(6)	—	1,015
Operating	274	—	—	—	12	286
Netback	770	—	—	6	(5)	771
Realized (Gain) Loss on Risk Management	137	—	—	—	—	137
Operating Margin	633	—	—	6	(5)	634

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

(2) Includes Tucker, Lloydminster Thermal and Lloydminster Cold/EOR 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 and transportation and blending have been re-presented to reflect a change in classification of marketing activities for the first and second quarters of 2021.

Nine Months Ended September 30, 2021 (\$ millions)	Basis of Netback Calculation					Natural Gas and Medium Oil		Total Oil sands
	Foster Creek	Christina Lake	Sunrise	Other Oil Sands ⁽²⁾	Total Bitumen and Heavy Oil			
Gross Sales	3,037	3,674	410	2,293	9,414	25		9,439
Royalties	487	733	13	227	1,460	2		1,462
Purchased Product	—	—	—	—	—	—		—
Transportation and Blending	520	386	83	165	1,154	—		1,154
Operating	517	506	117	618	1,758	25		1,783
Netback	1,513	2,049	197	1,283	5,042	(2)		5,040
Realized (Gain) Loss on Risk Management								584
Operating Margin								4,456

Nine 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	9,439	4,322	1,935	208		15,904	
Royalties	1,462	—	—	—		1,462	
Purchased Product	—	—	1,935	179		2,114	
Transportation and Blending	1,154	4,322	—	—		5,476	
Operating	1,783	—	—	10		1,793	
Netback	5,040	—	—	19		5,059	
Realized (Gain) Loss on Risk Management	584	—	—	—		584	
Operating Margin	4,456	—	—	19		4,475	

Nine Months Ended September 30, 2020 (\$ millions)	Basis of Netback Calculation					Natural Gas and Medium Oil		Total Oil sands
	Foster Creek	Christina Lake	Sunrise	Other Oil Sands ⁽²⁾	Total Bitumen and Heavy Oil			
Gross Sales	1,244	1,438	—	—	2,682	—		2,682
Royalties	67	132	—	—	199	—		199
Purchased Product	—	—	—	—	—	—		—
Transportation and Blending	523	431	—	—	954	—		954
Operating	404	399	—	—	803	—		803
Netback	250	476	—	—	726	—		726
Realized (Gain) Loss on Risk Management								228
Operating Margin								498

Nine Months Ended September 30, 2020 (\$ millions) ⁽³⁾	Basis of Netback Calculation		Adjustments				Per Interim Consolidated Financial Statements ⁽¹⁾	
	Total Oil Sands	Condensate	Third-party Sourced	Inventory Write-down ⁽⁵⁾	Other		Total Oil Sands	
Gross Sales	2,682	2,599	828	—	8		6,117	
Royalties	199	—	—	1	—		200	
Purchased Product	—	—	828	—	(22)		806	
Transportation and Blending	954	2,599	—	(1)	—		3,552	
Operating	803	—	—	—	36		839	
Netback	726	—	—	—	(6)		720	
Realized (Gain) Loss on Risk Management	228	—	—	—	—		228	
Operating Margin	498	—	—	—	(6)		492	

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

(2) Includes Tucker, Lloydminster Thermal and Lloydminster cold/EOR 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.

Conventional

Three Months Ended September 30, 2021 (\$ millions)	Basis of Netback Calculation	Adjustments		Per Interim Consolidated Financial Statements ⁽¹⁾
	Conventional	Third-party Sourced	Other ⁽²⁾	Conventional
Gross Sales	378	445	10	833
Royalties	40	—	—	40
Purchased Product	—	445	—	445
Transportation and Blending	20	—	—	20
Operating	125	—	10	135
Netback	193	—	—	193
Realized (Gain) Loss on Risk Management	—	2	—	2
Operating Margin	193	(2)	—	191

Three Months Ended September 30, 2020 (\$ millions)	Basis of Netback Calculation	Adjustments		Per Interim Consolidated Financial Statements ⁽¹⁾
	Conventional	Third-party Sourced	Other ⁽²⁾	Conventional
Gross Sales	145	76	11	232
Royalties	24	—	—	24
Purchased Product	—	76	—	76
Transportation and Blending	21	—	—	21
Operating	76	—	5	81
Netback	24	—	6	30
Realized (Gain) Loss on Risk Management	—	—	—	—
Operating Margin	24	—	6	30

Nine Months Ended September 30, 2021 (\$ millions)	Basis of Netback Calculation	Adjustments		Per Interim Consolidated Financial Statements ⁽¹⁾
	Conventional	Third-party Sourced	Other ⁽²⁾	Conventional
Gross Sales	1,069	1,113	53	2,235
Royalties	103	—	—	103
Purchased Product	—	1,113	—	1,113
Transportation and Blending	57	—	—	57
Operating	393	—	24	417
Netback	516	—	29	545
Realized (Gain) Loss on Risk Management	—	2	—	2
Operating Margin	516	(2)	29	543

Nine Months Ended September 30, 2020 (\$ millions)	Basis of Netback Calculation	Adjustments		Per Interim Consolidated Financial Statements ⁽¹⁾
	Conventional	Third-party Sourced	Other ⁽²⁾	Conventional
Gross Sales	416	186	34	636
Royalties	28	—	—	28
Purchased Product	—	186	(2)	184
Transportation and Blending	63	—	—	63
Operating	230	—	18	248
Netback	95	—	18	113
Realized (Gain) Loss on Risk Management	—	—	—	—
Operating Margin	95	—	18	113

(1) Found in Note 1 of the Interim 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

Three Months Ended September 30, 2021 (\$ millions)	Basis of Netback Calculation				Adjustment	Per Interim Consolidated Financial Statements ⁽²⁾
	China	Indonesia ⁽¹⁾	Atlantic	Total Offshore	Equity Adjustment ⁽¹⁾	Total Offshore
Gross Sales	336	60	68	464	(60)	404
Royalties	20	11	4	35	(11)	24
Purchased Product	—	—	—	—	—	—
Transportation and Blending	—	—	3	3	—	3
Operating	27	7	21	55	(6)	49
Netback	289	42	40	371	(43)	328
Realized (Gain) Loss on Risk Management				—	—	—
Operating Margin				371	(43)	328

Nine Months Ended September 30, 2021 (\$ millions)	Basis of Netback Calculation				Adjustment	Per Interim Consolidated Financial Statements ⁽²⁾
	China	Indonesia ⁽¹⁾	Atlantic	Total Offshore	Equity Adjustment ⁽¹⁾	Total Offshore
Gross Sales	965	162	297	1,424	(162)	1,262
Royalties	53	23	21	97	(23)	74
Purchased Product	—	—	—	—	—	—
Transportation and Blending	—	—	10	10	—	10
Operating	71	21	92	184	(18)	166
Netback	841	118	174	1,133	(121)	1,012
Realized (Gain) Loss on Risk Management				—	—	—
Operating Margin				1,133	(121)	1,012

(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 Interim 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 September 30,		Nine Month Ended September 30,	
	2021	2020	2021	2020
Oil Sands				
Foster Creek	206.3	158.3	173.5	166.2
Christina Lake	238.1	238.1	230.5	222.0
Sunrise ⁽³⁾	25.5	—	23.6	—
Other Oil Sands	143.2	—	143.8	—
Total Oil Sands	613.1	396.4	571.4	388.2
Conventional	131.4	85.7	136.2	91.1
Sales before Internal Consumption	744.5	482.1	707.6	479.3
Less: Internal Consumption ⁽²⁾	(84.0)	(53.4)	(85.2)	(55.6)
Offshore				
Asia Pacific - China	49.8	—	50.1	—
Asia Pacific - Indonesia	10.0	—	9.4	—
Atlantic	7.8	—	12.6	—
Total Offshore	67.6	—	72.1	—
Total Sales	728.1	428.7	694.5	423.7

(1) Presented on dry bitumen basis.

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

(3) Sunrise sales volumes have been re-presented to reflect a change in classification of marketing activities for the first and second quarters of 2021.