Cenovus Energy Inc.

Management's Discussion and Analysis (unaudited)

For the Periods Ended September 30, 2022

(Canadian Dollars)

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the periods ended September 30, 2022

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 1, 2022 should be read in conjunction with our September 30, 2022 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2021 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2021 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of November 1, 2022 unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus management ("Management") prepared the MD&A. The 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 annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Basis of Presentation

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

OVERVIEW OF CENOVUS

We are a Canadian-based integrated energy company headquartered in Calgary, Alberta. Our common shares and common share purchase warrants ("Cenovus Warrants") are listed on the Toronto Stock Exchange ("TSX") and New York Stock Exchange. Our cumulative redeemable preferred shares series 1, 2, 3, 5 and 7 are listed on the TSX. We are the second largest Canadian-based crude oil and natural gas producer, with upstream operations in Canada and the Asia Pacific region, and the second largest Canadian-based refiner and upgrader, with downstream operations in Canada and the United States ("U.S."). On January 1, 2021, Cenovus and Husky Energy Inc. ("Husky") closed a transaction to combine the two companies through a plan of arrangement (the "Arrangement").

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 and refining operations in Canada and the U.S., and commercial fuel operations across Canada.

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

During the nine months ended September 30, 2022, crude oil production from our Oil Sands assets averaged 578.9 thousand barrels per day and total upstream production averaged 779.2 thousand BOE per day. Downstream crude oil throughput was 497.8 thousand barrels per day. Refer to the Operating and Financial Results section of this MD&A for a summary of production by product type.

Our Strategy

Our strategy is focused on maximizing shareholder value through competitive cost structures and optimizing margins, while delivering top-tier safety performance and environmental, social and governance ("ESG") leadership. The Company prioritizes Free Funds Flow generation that enables debt reduction, shareholder returns through a combination of base dividend growth and flexible return mechanisms, reinvestment in the business and diversification.

Shareholder Returns and Capital Allocation Framework

Maintaining a strong balance sheet with the resilience to withstand price volatility and capitalize on opportunities throughout the commodity cycle is a key element of Cenovus's capital allocation framework. On April 27, 2022, we announced our updated capital allocation framework to continue to strengthen our balance sheet, which enable flexibility in both high and low commodity price environments and improve our shareholder value proposition.

We have set an ultimate Net Debt Target of $4 billion, which serves as a floor on Net Debt. We plan to return incremental value to shareholders, through share buybacks and/or variable dividends, as follows:

- When Net Debt is less than $9 billion and above $4 billion at quarter-end, we will target to allocate 50 percent of the Excess Free Funds Flow achieved in the following quarter to shareholder returns, while still continuing to deleverage the balance sheet until we reach the Net Debt Target of $4 billion.
- When Net Debt is above $9 billion at quarter-end, we plan to allocate all of the following quarter's Excess Free Funds Flow to deleveraging the balance sheet.
- When Net Debt is at the $4 billion floor at quarter-end, we will target to return 100 percent of the following quarter's Excess Free Funds Flow to shareholder returns.

Excess Free Funds Flow is defined as Free Funds Flow[(1)]:

- Minus base dividends paid on common shares in the quarter.
- Minus dividends paid on preferred shares in the quarter.
- Minus other uses of cash, including decommissioning liabilities and principal repayment of leases, in the quarter.
- Minus any net acquisition costs from acquisition activities closing in the quarter.
- Plus any proceeds from or less any payments related to divestiture activities closing in the quarter.

The Company's capital allocation framework enables a shift to paying out a higher percentage of Excess Free Funds Flow to common shareholders, with lower leverage and a lower risk profile. Our $4 billion Net Debt Target represents a Net Debt to Adjusted Funds Flow Ratio Target of approximately 1.0 times at the bottom of the cycle.

(1) *See the Liquidity and Capital Resources section of this MD&A for the calculation of Free Funds Flow.*

Share buybacks will continue to be executed opportunistically, driven by return thresholds. Where the value of share buybacks in a quarter is less than the targeted value of returns, the remainder will be delivered through a variable dividend payable for that quarter. Where the value of share buybacks in a quarter is greater than the targeted value of returns, no variable dividend will be paid for that quarter.

On June 30, 2022, our Net Debt position was $7.5 billion and as a result, our returns to shareholders target for the three months ended September 30, 2022, was 50 percent of that quarter's Excess Free Funds Flow. During the three months ended September 30, 2022, we generated cash from operating activities of $4.1 billion, Excess Free Funds Flow of $1.8 billion and returned $659 million to our shareholders through share buybacks. As such, on November 1, 2022, the Company's Board of Directors declared a fourth quarter variable dividend of $0.114 per common share, payable on December 2, 2022, to common shareholders of record as at November 18, 2022.

($ millions)	**Three Months Ended September 30, 2022**
Excess Free Funds Flow [(1)]	**1,756**
Target Return [(2)]	**878**
Less: Purchase of Common Shares Under our Normal Course Issuer Bid ("NCIB")	**(659)**
Returns to Shareholders Under Target Before Variable Dividend	**219**

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

(2) Based on our capital allocation framework, as a result of Net Debt as at June 30, 2022, being less than $9 billion and greater than $4 billion, Target Return was determined to be 50 percent of Excess Free Funds Flow for the three months ended September 30, 2022.

On September 30, 2022, our Net Debt position was $5.3 billion and as a result we expect our returns to shareholders target for the three months ended December 31, 2022, to be 50 percent of the fourth quarter's Excess Free Funds Flow.

Key Priorities for 2022

We aim to deliver on our strategy through five key strategic objectives:

Top Tier Safety Performance and ESG Leadership

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

A path and program for achieving our targets in each of our five ESG focus areas has been established, including identifying the levers and resources that will be required. Additional information on management's efforts and performance across ESG topics, including our ESG targets and plans to achieve them, are available in Cenovus's 2021 ESG report at cenovus.com.

Competitive Cost Structures and Optimizing Margins

We continue to target additional cost savings and margin enhancements through further physical integration of upstream assets with downstream assets, which is expected to shorten the value chain and reduce condensate costs associated with heavy oil transportation. We continue to look for ways to improve efficiencies across Cenovus to drive incremental capital, operating, and general and administrative cost reductions.

Maintaining and Further Reducing Debt Levels

As at September 30, 2022, our long-term debt, including current portion, was $8.8 billion (December 31, 2021 – $12.4 billion) and our Net Debt position was $5.3 billion (December 31, 2021 – $9.6 billion). As a result of strong cash from operating activities, we redeemed a significant amount of debt and decreased Net Debt during the nine months ended September 30, 2022. Our Net Debt to Adjusted EBITDA Ratio was 0.4 times and our Net Debt to Adjusted Funds Flow Ratio was 0.5 times at September 30, 2022. Maintaining a strong balance sheet provides financial flexibility to manage our business through commodity price volatility.

Returns-focused Capital Allocation

The Company's sustaining capital program and base dividend are sustainable at US$45 WTI per barrel, and provide opportunities to sustainably grow shareholder returns. On November 1, 2022, the Company's Board of Directors declared a fourth quarter base dividend of $0.105 per common share and a fourth quarter variable dividend of $0.114 per common share. The base dividend is payable on December 30, 2022, to common shareholders of record as at December 15, 2022. The variable dividend is payable on December 2, 2022, to common shareholders of record as at November 18, 2022. During the three and nine months ended September 30, 2022, we returned $659 million and $2.1 billion, respectively, to our shareholders through share buybacks.

During the quarter, we closed the previously announced purchase of the remaining 50 percent interest in Sunrise and the sales of 337 gas stations within our retail fuels network.

In addition, we announced an agreement with BP Products North America Inc. ("BP") to acquire BP's 50 percent interest in the Toledo Refinery in Ohio. The acquisition will provide us full ownership and operatorship and further integrate our heavy oil production and refining capabilities. The transaction is expected to give us an additional 80.0 thousand barrels per day of downstream throughput capacity, including 45.0 thousand barrels per day of heavy oil refining capacity, with opportunities to further optimize our heavy oil value chain through integration with our upstream assets.

On September 20, 2022, a tragic fire occurred at the Toledo Refinery, resulting in two worker fatalities. Investigations into the cause of the incident are ongoing and the refinery remains shut down in a safe state. We continue to assess the status and timing of closing the transaction.

In 2022, we anticipate our total capital expenditures will be between $3.3 billion and $3.7 billion, including $500 million to $550 million (excluding insurance proceeds) for the Superior Refinery rebuild. We will continue to be disciplined with our capital allocation.

Growing Free Funds Flow Through Pricing Cycles

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

Cenovus has a track record of operational reliability for our upstream assets. We expect our annual upstream production to average between 780 thousand BOE per day and 810 thousand BOE per day. Given the incident at the Toledo Refinery, we now expect our downstream crude oil throughput to fall modestly outside the guidance range of 530 thousand barrels per day to 580 thousand barrels per day in 2022. We continue to monitor the overall market dynamics to assess how we manage our upstream production and downstream throughput 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.

Our 2022 guidance dated July 27, 2022, is available on our website at cenovus.com. For further details see the Operating and Financial Results section of this MD&A.

Our Operations

The Company operates through the following reportable segments:

Upstream Segments

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

Downstream Segments

- **Canadian Manufacturing,** includes the owned and operated Lloydminster upgrading and asphalt refining complex, which upgrades heavy oil and bitumen into synthetic crude oil, diesel, asphalt and other ancillary products. Cenovus seeks to maximize the value per barrel from its heavy oil and bitumen production through its integrated network of assets. In addition, Cenovus owns and operates the Bruderheim crude-by-rail terminal and two ethanol plants. Cenovus also markets its production and third-party commodity trading volumes of synthetic crude oil, asphalt and ancillary products.
- **U.S. Manufacturing,** includes the refining of crude oil to produce gasoline, diesel, jet fuel, asphalt and other products at the wholly-owned Lima Refinery and Superior Refinery, the jointly-owned Wood River and Borger refineries (jointly owned with operator Phillips 66) and the jointly-owned Toledo Refinery (jointly owned with operator BP). Cenovus also markets some of its own and third-party volumes of refined petroleum products including gasoline, diesel and jet fuel.
- **Retail,** includes the sale of Cenovus's own and third-party volumes of refined petroleum products, including gasoline and diesel, through retail, cardlock, travel center locations, bulk petroleum outlets, and wholesale channels in Canada. In September 2022, we divested the majority of our retail fuels network.

Corporate and Eliminations

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

QUARTERLY RESULTS OVERVIEW

During the third quarter of 2022, we continued to deliver solid upstream operating performance and strong financial results. We continued to optimize our portfolio as we closed the previously announced Sunrise acquisition and the retail asset divestiture. These transactions enable us to focus on our core strength in the oil sands, and with 100 percent ownership, apply our operating model at Sunrise. Commodity prices remained high compared with all of 2021 and the first quarter of 2022, despite weakening since the second quarter of 2022. WTI averaged US$91.55, an increase of 30 percent from the third quarter of 2021 and a decrease of 16 percent from the second quarter of 2022. Market crack spreads improved significantly compared with the third quarter of 2021, though weakened compared with historic highs in the second quarter of 2022.

Overall, our continued focus on health and safety as well as competitive cost structures, combined with high commodity prices, drove strong financial results. We reduced Total Debt by $2.5 billion and Net Debt by $2.3 billion from June 30, 2022, and returned $864 million to shareholders through share buybacks and common share dividends. On November 1, 2022, the Board declared a variable dividend of $0.114 per common share, payable in the fourth quarter, in addition to the base dividend.

Summary of Quarterly Results

	Nine Months Ended September 30,		2022			2021				2020	
($ millions, except where indicated)	**2022**	2021	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Production Volumes [1] (MBOE/d)	**779.2**	780.1	**777.9**	761.5	798.6	825.3	804.8	765.9	769.3	467.2	471.8
Crude Oil Throughput [2] (Mbbls/d)	**497.8**	521.0	**533.5**	457.3	501.8	469.9	554.1	539.0	469.1	169.0	191.1
Revenues [3]	**52,834**	32,631	**17,471**	19,165	16,198	13,726	12,701	10,637	9,293	3,543	3,737
Operating Margin [4]	**11,481**	6,773	**3,339**	4,678	3,464	2,600	2,710	2,184	1,879	625	594
Cash From Operating Activities	**8,433**	3,735	**4,089**	2,979	1,365	2,184	2,138	1,369	228	250	732
Adjusted Funds Flow [4]	**8,632**	5,300	**2,951**	3,098	2,583	1,948	2,342	1,817	1,141	333	407
Capital Investment	**2,434**	1,728	**866**	822	746	835	647	534	547	242	148
Free Funds Flow [4]	**6,198**	3,572	**2,085**	2,276	1,837	1,113	1,695	1,283	594	91	259
Excess Free Funds Flow [4][5]	**N/A**	N/A	**1,756**	2,020	2,615	1,169	1,626	1,244	462	N/A	N/A
Net Earnings (Loss) [6]	**5,666**	995	**1,609**	2,432	1,625	(408)	551	224	220	(153)	(194)
Per Share - Basic ($)	**2.87**	0.48	**0.83**	1.23	0.81	(0.21)	0.27	0.11	0.10	(0.12)	(0.16)
Per Share - Diluted ($)	**2.79**	0.47	**0.81**	1.19	0.79	(0.21)	0.27	0.11	0.10	(0.12)	(0.16)
Total Assets	**55,086**	54,594	**55,086**	55,894	55,655	54,104	54,594	53,384	53,378	32,770	32,857
Total Long-Term Liabilities	**19,378**	22,929	**19,378**	20,742	21,889	23,191	22,929	22,972	24,266	13,704	13,889
Long-Term Debt, Including Current Portion	**8,774**	12,986	**8,774**	11,228	11,744	12,385	12,986	13,380	13,947	7,441	7,797
Net Debt	**5,280**	11,024	**5,280**	7,535	8,407	9,591	11,024	12,390	13,340	7,184	7,530
Cash Returns to Shareholders											
Common Shares – Base Dividends	**481**	106	**205**	207	69	70	35	36	35	—	—
Base Dividends Per Common Share ($)	**0.245**	0.053	**0.105**	0.105	0.035	0.035	0.018	0.018	0.018	—	—
Purchase of Common Shares Under NCIB	**2,143**	—	**659**	1,018	466	265	—	—	—	—	—
Preferred Share Dividends	**26**	26	**9**	8	9	8	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.
(3) Prior period results were revised for a change in presentation of product swaps and certain third-party purchases used in blending and optimization activities, and to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.
(4) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(5) New metric as of June 30, 2022, used to determine returns to shareholders.
(6) Net earnings (loss) for all periods in the table above is the same as net earnings (loss) from continuing operations.

Operations under management's control performed well in the third quarter.

- We delivered safe and reliable operations at our operated assets.
- We achieved first oil at our Spruce Lake North thermal plant. Production ramped up to approximately 10.0 thousand barrels per day by the end of the quarter.
- Upstream production averaged 777.9 thousand BOE per day in the third quarter, compared with 761.5 thousand BOE per day in the second quarter of 2022 and 804.8 thousand BOE per day in the third quarter of 2021. See the Operating and Financial Results section of this MD&A for a summary of upstream production by product type.
- Downstream crude oil throughput averaged 533.5 thousand barrels per day in the third quarter, an increase of 76.2 thousand barrels per day compared with the second quarter of 2022, and a decrease of 20.6 thousand barrels per day compared with the third quarter of 2021.

Revenue increased 38 percent to $17.5 billion compared with the third quarter of 2021, and decreased 9 percent from the second quarter of 2022, primarily due to changes in commodity pricing. Our realized sales price from our upstream operations was $83.43 per BOE in the third quarter of 2022, compared with $66.44 per BOE in the third quarter of 2021. We also realized higher refining margins in our downstream operations compared with the third quarter of 2021.

Cash from operating activities increased $2.0 billion and $1.1 billion compared with the third quarter of 2021 and second quarter of 2022, respectively. Operating margin increased $629 million compared with the third quarter of 2021 and decreased $1.3 billion compared with the second quarter of 2022. Adjusted Funds Flow was $3.0 billion in third quarter of 2022, an increase of $609 million compared with the third quarter of 2021, and relatively unchanged from the second quarter of 2022 despite the decrease in operating margin. In the third quarter of 2022, we recorded considerably less cash taxes and paid less cash on the contingent payment than the second quarter of 2022.

We continued to strengthen our balance sheet and focus on our top-tier asset portfolio.

- During the quarter, we continued to deleverage our balance sheet as we purchased US$2.2 billion in principal of notes due between 2025 and 2043. Our Net Debt decreased by $2.3 billion compared with June 30, 2022.
- On August 8, 2022, we announced an agreement to purchase the remaining 50 percent interest in the Toledo Refinery (the "Toledo Acquisition") from BP giving Cenovus full ownership and further integrating our heavy oil production and refining capabilities. On September 20, 2022, there was an incident at the refinery and it remains shut down in a safe state.
- On August 31, 2022, we closed the acquisition of the remaining 50 percent interest in Sunrise (the "Sunrise Acquisition") for cash of $394 million, net of closing adjustments, a variable payment with a maximum cumulative value of $600 million expiring in eight quarters subsequent to August 31, 2022, and our 35 percent position in the undeveloped Bay du Nord project offshore Newfoundland and Labrador.
- On September, 13, 2022, we closed the sales of 337 gas stations within our retail fuels network for net cash proceeds of $404 million.

We demonstrated our commitment to returning cash to shareholders.

- Cenovus purchased and cancelled 29 million common shares for $659 million through our NCIB in the third quarter (97 million common shares for $2.1 billion in the first nine months of 2022). Our existing NCIB expires on November 8, 2022.
- On November 1, 2022, the Board approved filing an application with the TSX to renew our NCIB to purchase up to 10 percent of the Company's public float, or approximately 137 million of the Company's common shares for twelve months once approved by the TSX.
- On November 1, 2022, the Board declared a fourth quarter base dividend of $0.105 per common share payable on December 30, 2022, to common shareholders of record as at December 15, 2022.
- On November 1, 2022, the Board declared a fourth quarter variable dividend of $0.114 per common share payable on December 2, 2022, to common shareholders of record as at November 18, 2022.
- On November 1, 2022, the Board declared fourth quarter dividends for our preferred shares of $9 million, payable on January 3, 2023, to preferred shareholders of record as at December 15, 2022.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results — Upstream

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2022	**Percent Change**	2021	**2022**	**Percent Change**	2021
Upstream Production Volumes by Segment [1] (MBOE/d)						
Oil Sands	**587.1**	**(2)**	599.1	**580.9**	**2**	568.9
Conventional	**126.2**	**(4)**	132.0	**128.0**	**(6)**	136.4
Offshore	**64.6**	**(12)**	73.7	**70.3**	**(6)**	74.8
Total Production Volumes	**777.9**	**(3)**	804.8	**779.2**	**—**	780.1
Upstream Production Volumes by Product						
Bitumen (Mbbls/d)	**568.2**	**(1)**	576.5	**562.4**	**3**	546.2
Heavy Crude Oil (Mbbls/d)	**16.8**	**(18)**	20.5	**16.5**	**(20)**	20.6
Light Crude Oil (Mbbls/d)	**16.0**	**(29)**	22.6	**19.8**	**(18)**	24.1
NGLs (Mbbls/d)	**32.1**	**(10)**	35.5	**35.4**	**(10)**	39.3
Conventional Natural Gas (MMcf/d)	**868.7**	**(3)**	897.9	**870.9**	**(3)**	899.5
Total Production Volumes (MBOE/d)	**777.9**	**(3)**	804.8	**779.2**	**—**	780.1
Total Upstream Sales Volumes [2] (MBOE/d)	**686.8**	**(6)**	728.1	**698.4**	**1**	694.5
Netback [3][4] ($/BOE)	**42.14**	**6**	39.74	**57.26**	**62**	35.35

(1) Refer to the Oil Sands, Conventional or Offshore Operating Results section of this MD&A for a summary of production by product type.

(2) Total upstream sales volumes exclude natural gas volumes used for internal consumption by the Oil Sands segment of 484 MMcf per day and 506 MMcf per day for the three months and nine months ended September 30, 2022, respectively (504 MMcf per day and 511 MMcf per day for the three and nine months ended September 30, 2021, respectively).

(3) Upstream revenue as found in Note 1 of the interim Consolidated Financial Statements was $9.0 billion and $28.8 billion in the three and nine months ended September 30, 2022, respectively (three and nine months ended September 30, 2021 – $6.6 billion and $18.0 billion, respectively).

(4) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

In the third quarter of 2022, production increased 16.4 thousand barrels per day compared with the second quarter of 2022, primarily due to:

- Turnaround activity at Christina Lake in the second quarter of 2022.
- The Sunrise Acquisition on August 31, 2022, adding approximately 8.0 thousand barrels per day in the quarter.
- First oil at the Spruce Lake North thermal plant. Production ramped up to approximately 10.0 thousand barrels per day by the end of the quarter.

The increase was partially offset by:

- Planned maintenance and an unplanned outage at Foster Creek in the third quarter of 2022.
- Planned maintenance in the Offshore segment in the third quarter of 2022.
- The transfer of a 12.5 percent working interest in the West White Rose field and satellite extensions to a partner on May 31, 2022.

In the third quarter of 2022, production decreased 26.9 thousand barrels per day compared with the same period in 2021. The decrease was primarily due to the disposition of the Tucker asset on January 31, 2022, the Wembley asset on February 28, 2022 and the restructuring of our working interest in the White Rose fields on May 31, 2022. Also contributing to the decrease were planned maintenance activities in the Conventional and Offshore segments. The decreases were offset by the Sunrise Acquisition and first oil at the Spruce Lake North thermal plant in the third quarter. Production at Foster Creek and Christina Lake was consistent in the third quarter of 2022 compared with 2021 due to new wells coming online in 2022 and the second half of 2021, offset by planned routine maintenance and operational outages at Foster Creek during the quarter.

Year-to-date, production was relatively consistent compared with 2021 due to the same factors as discussed above, combined with the impacts of a planned turnaround and operational outages at Foster Creek in the second quarter of 2021.

Selected Operating Results — Downstream

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2022	**Percent Change**	2021	**2022**	**Percent Change**	2021
Downstream Manufacturing Crude Oil Throughput (Mbbls/d)						
Canadian Manufacturing	**98.5**	**(9)**	108.3	**92.5**	**(13)**	106.0
U.S. Manufacturing	**435.0**	**(2)**	445.8	**405.3**	**(2)**	415.0
Total Throughput	**533.5**	**(4)**	554.1	**497.8**	**(4)**	521.0
Retail [(1)] (millions of litres/d)						
Fuel Sales, Including Wholesale	**6.9**	**(5)**	7.3	**6.7**	**(3)**	6.9

(1) On September 13, 2022, we closed the sales of 337 gas stations within our retail fuels network. We retained our commercial fuels business, which includes approximately 170 cardlock, bulk plant and travel centre locations.

In the Canadian Manufacturing segment, throughput increased 17.6 thousand barrels per day in the third quarter of 2022 compared with the second quarter, following completion of planned turnarounds at the Lloydminster Upgrader and Lloydminster Refinery in the second quarter.

Canadian Manufacturing throughput decreased slightly in the three months ended September 30, 2022, compared with 2021 due to temporary unplanned outages at the Lloydminster Upgrader and Lloydminster Refinery in the third quarter of 2022. Year-to-date, throughput decreased 13.5 thousand barrels per day compared with 2021, due to the planned turnarounds in the second quarter and unplanned outages in the third quarter of 2022.

In the U.S. Manufacturing segment, throughput increased 58.6 thousand barrels per day in the third quarter of 2022 compared with the second quarter. The increase was primarily due to planned spring turnarounds at the non-operated Wood River and Borger refineries completed in the second quarter, and a planned turnaround at the non-operated Toledo Refinery starting in the second quarter and completed in early August. The increase was partially offset by a planned fall turnaround at the Wood River Refinery that commenced in September and was completed in October, and the incident at the Toledo Refinery on September 20, 2022.

U.S. Manufacturing throughput was relatively consistent in the third quarter of 2022, compared with 2021. At the Wood River and Borger refineries, throughput increased to 224.2 thousand barrels per day compared with 2021 due to strong operational performance in the quarter. The increase was partially offset by the planned fall turnaround at the Wood River Refinery. Toledo Refinery throughput decreased 24.4 thousand barrels per day compared with 2021 due to the planned turnaround completed in early August, combined with the incident in September. At the Lima Refinery, crude oil throughput was 164.2 thousand barrels per day in the third quarter, an increase compared with 2021 as production slowed at the end of September 2021 as we prepared for a planned turnaround. Year-to-date, throughput was relatively consistent compared with 2021 as favourable market conditions offset the impacts of planned turnarounds at our non-operated facilities at the Wood River, Borger and Toledo refineries in 2022.

Selected Consolidated Financial Results

Operating Margin

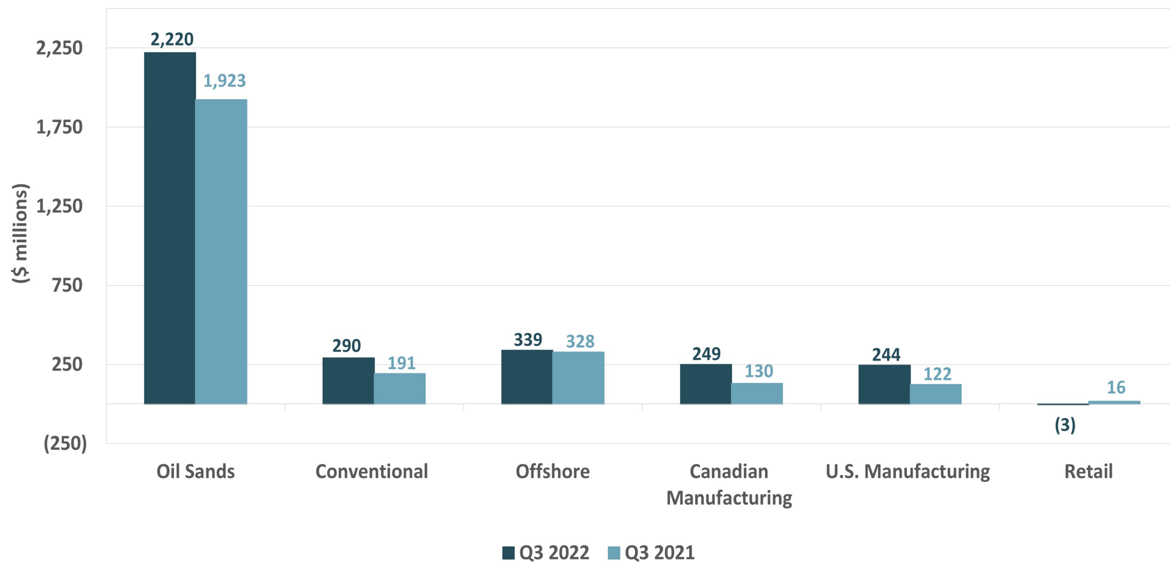
Operating Margin is a specified financial measure and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2022**	2021	**2022**	2021
Gross Sales [(1)]	**21,316**	14,884	**62,989**	38,145
Less: Royalties	**1,226**	733	**3,993**	1,639
Revenues	**20,090**	14,151	**58,996**	36,506
Expenses				
Purchased Product [(1)]	**12,279**	7,782	**31,550**	19,039
Transportation and Blending [(1)]	**2,803**	2,137	**9,235**	6,115
Operating Expenses	**1,695**	1,337	**5,125**	3,945
Realized (Gain) Loss on Risk Management Activities	**(26)**	185	**1,605**	634
Operating Margin	**3,339**	2,710	**11,481**	6,773

(1) Prior period results were revised for a change in presentation of product swaps and certain third-party purchases used in blending and optimization activities, and to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

Operating Margin by Segment

Three Months Ended September 30



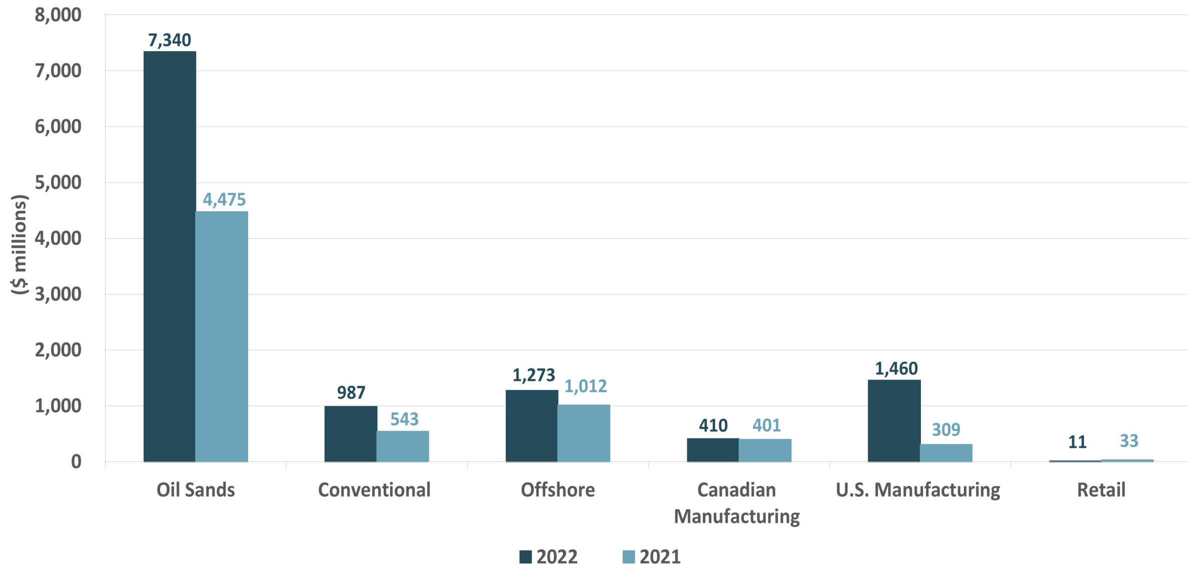
Operating Margin increased in the three months ended September 30, 2022, compared with the same period in 2021, primarily due to:

- Higher average realized crude oil, NGLs and natural gas sales prices resulting from higher benchmark pricing.
- Increased refining margins from our downstream business resulting from higher market crack spreads, partially offset by the increased cost of feedstock processed in the quarter from inventory at a higher price in the U.S. Manufacturing segment.
- Realized risk management losses in the third quarter of 2021 compared with gains in 2022. The losses in 2021 primarily related WTI crude oil sales price risk management activities. Those activities were suspended earlier this year.

These increases in Operating Margin were partially offset by:

- Increased royalties and fuel costs, both resulting from significantly higher commodity pricing.
- Planned and unplanned outages in our downstream operations, which impacted sales volumes and operating expenses.
- Lower sales volumes from our upstream business.
- Increased blending costs due to higher condensate prices.

Nine Months Ended September 30



Operating Margin increased in the nine months ended September 30, 2022, compared with the same period in 2021, mainly due to:

- Higher average realized crude oil, NGLs and natural gas sales prices resulting from higher benchmark pricing.
- Increased refining margins from our downstream business resulting from higher market crack spreads.

These increases in Operating Margin were partially offset by:

- Increased royalties and fuel costs, both resulting from significantly higher commodity pricing.
- Planned turnarounds in our downstream operations in the second quarter of 2022, which impacted sales volumes and operating expenses.
- Higher realized risk management losses on the settlement of benchmark prices relative to our risk management contract prices in 2022. In the second quarter of 2022, all WTI risk management contracts related to our crude oil sales price risk management activities were closed.
- Increased blending costs due to higher condensate prices.

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

Adjusted Funds Flow is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
($ millions)	**2022**	2021	**2022**	2021
Cash From (Used in) Operating Activities	**4,089**	2,138	**8,433**	3,735
(Add) Deduct:				
Settlement of Decommissioning Liabilities	**(55)**	(38)	**(101)**	(67)
Net Change in Non-Cash Working Capital	**1,193**	(166)	**(98)**	(1,498)
Adjusted Funds Flow	**2,951**	2,342	**8,632**	5,300

Cash From Operating Activities and Adjusted Funds Flow were higher in the three months ended September 30, 2022, compared with 2021 due to increased Operating Margin, as discussed above. The increase was partially offset by a higher quarterly contingent payment in the third quarter of 2022.

The change in non-cash working capital in the third quarter of 2022 was a result of realized accounts receivable and inventory balances from June 30, 2022, when commodity prices were higher and lower accounts payable.

Cash From Operating Activities and Adjusted Funds Flow were higher in the nine months ended September 30, 2022, compared with 2021 due to increased Operating Margin, as discussed above, combined with lower integration costs. The increase was partially offset by higher cash taxes and higher quarterly contingent payments in the first nine months of 2022.

The change in non-cash working capital in the first nine months of 2022 was relatively small as higher commodity prices resulted in increased accounts receivable and inventory, offset by higher income tax payable on September 30, 2022, compared with December 31, 2021.

Net Earnings (Loss)

($ millions)	Three Months Ended	Nine Months Ended
Net Earnings (Loss) for the Periods Ended September 30, 2021	**551**	**995**
Increase (Decrease) due to:		
Operating Margin	**629**	**4,708**
Corporate and Eliminations:		
General and Administrative	**30**	**(54)**
Finance Costs	**153**	**205**
Integration Costs	**18**	**223**
Unrealized Foreign Exchange Gain (Loss)	**(187)**	**(639)**
Revaluation Gains	**549**	**549**
Re-measurement of Contingent Payments	**244**	**429**
Gain (Loss) on Divestiture of Assets	**(85)**	**147**
Other Income (Loss), net	**(48)**	**259**
Other (1)	**101**	**146**
Unrealized Risk Management Gain (Loss) (2)	**(23)**	**316**
Depreciation, Depletion and Amortization	**106**	**25**
Exploration Expense	**(68)**	**(84)**
Income Tax Recovery (Expense)	**(361)**	**(1,559)**
Net Earnings (Loss) for the Periods Ended September 30, 2022	**1,609**	**5,666**

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

(2) All WTI positions related to crude oil sales price risk management were closed by June 30, 2022.

Net earnings in the third quarter of 2022 improved compared with 2021 due to:

- Increased Operating Margin, as discussed above.
- Revaluation gains of $549 million related to the Sunrise Acquisition.
- A gain on re-measurement of contingent payment of $109 million in 2022 related to the Sunrise Acquisition, compared with a loss of $135 million in 2021 related to the acquisition of the 50 percent interest in the FCCL Partnership.
- Lower DD&A, mainly due to asset write-downs in the Oil Sands segment in the third quarter of 2021.
- Finance costs of $207 million compared with $360 million in 2021. In the third quarter of 2022, finance costs included a $4 million net discount on the redemption of long-term debt, compared with a $115 million net premium in the third quarter of 2021.

Net earnings in the first nine months of 2022 improved compared with 2021 due to:

- Increased Operating Margin, as discussed above.
- Revaluation gains of $549 million related to the Sunrise Acquisition in the third quarter of 2022.
- A loss on re-measurement of the contingent payments of $142 million compared with $571 million in 2021.
- Unrealized risk management gains of $74 million, compared with losses of $242 million in 2021.
- Higher other income primarily due to insurance proceeds related to the Superior Refinery.
- Integration costs of $79 million, compared with $302 million in 2021.
- Finance costs of $631 million compared with $836 million in 2021. In the first nine months of 2022, finance costs included a $29 million net discount on the redemption of long-term debt, compared with a $115 million net premium in 2021. A lower average long-term debt balance in 2022 also contributed to the decrease.
- Net gains on the divestiture of assets of $244 million in 2022, related to the Tucker and Wembley dispositions, and the divestiture of a 12.5 percent interest in the White Rose field and satellite extensions, partially offset by a loss on the retail assets divestiture.

The increase in net earnings for the three months and nine months ended September 30, 2022 was partially offset by higher income tax expense and higher unrealized foreign exchange losses as the Canadian dollar at September 30, 2022, weakened relative to the U.S. dollar.

Net Debt

As at ($ millions)	September 30, 2022	December 31, 2021
Short-Term Borrowings	—	79
Current Portion of Long-Term Debt	—	—
Long-Term Debt	8,774	12,385
Total Debt	**8,774**	12,464
Less: Cash and Cash Equivalents	(3,494)	(2,873)
Net Debt	**5,280**	9,591

Long-term debt decreased by $3.6 billion and Net Debt decreased by $4.3 billion from December 31, 2021. During the third quarter, long-term debt decreased by $2.5 billion and Net Debt decreased by $2.3 billion. In the three months ended September 30, 2022, we purchased US$2.2 billion in principal of notes due between 2025 and 2043. In the first six months of 2022, we purchased the remaining US$384 million in principal of outstanding notes due in 2023 and 2024 and the full $750 million in principal of the outstanding 3.55 percent notes due in 2025. The decrease in long-term debt was partially offset as the Canadian dollar weakened relative to the U.S. dollar on September 30, 2022, impacting our U.S. dollar debt.

Capital Investment [(1)]

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	2022	2021	2022	2021
Upstream				
Oil Sands	360	198	1,111	617
Conventional	67	41	188	135
Offshore	81	69	225	130
	508	308	1,524	882
Downstream				
Canadian Manufacturing	17	9	67	23
U.S. Manufacturing	300	301	774	743
Retail	7	16	10	22
	324	326	851	788
Corporate and Eliminations	34	13	59	58
Capital Investment	**866**	647	**2,434**	1,728

(1) Includes expenditures on PP&E, exploration and evaluation ("E&E") assets, and capitalized interest.

Oil Sands capital investment in the first nine months of 2022 was primarily focused on sustaining activities at Christina Lake, Foster Creek, the Lloydminster thermal assets and Sunrise, and the drilling of stratigraphic test wells as part of our integrated winter program.

Conventional capital investment in the first nine months of 2022 focused on sustaining drilling, completion and tie-in programs.

Offshore capital investment in the first nine months of 2022 was primarily for the Terra Nova asset life extension ("ALE") project and capital for the West White Rose project in the Atlantic region. On May 31, 2022, Cenovus and our partners announced the restart of the West White Rose project offshore Newfoundland and Labrador.

U.S. Manufacturing capital investment in the first nine months of 2022 focused primarily on the Superior Refinery rebuild, refining reliability initiatives at the Wood River, Borger and Toledo refineries, and yield optimization projects at the Wood River Refinery.

Capital investment in the third quarter of 2022 was impacted by rising costs due to inflation.

Drilling Activity

	Net Stratigraphic Test Wells and Observation Wells		Net Production Wells [1]	
Nine Months Ended September 30,	**2022**	2021	**2022**	2021
Foster Creek	**52**	17	**22**	6
Christina Lake [2]	**—**	25	**21**	9
Sunrise	**15**	—	**2**	—
Lloydminster Thermal	**1**	—	**29**	21
Tucker	**6**	—	**—**	—
Lloydminster Conventional Heavy Oil	**—**	—	**—**	2
Other [3]	**16**	17	**—**	—
	90	59	**74**	38

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

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

	Nine Months Ended September 30, 2022			Nine Months Ended September 30, 2021		
(net wells)	**Drilled**	**Completed**	**Tied-in**	Drilled	Completed	Tied-in
Conventional	**19**	**28**	**29**	14	17	18

In the Offshore segment, we drilled and completed seven (2.8 net) planned development wells at the MBH and MDA fields in Indonesia in the first nine months of 2022 (2021 — no wells drilled, completed or tied-in). We achieved first gas production at the MBH field in October and expect first gas production from the MDA field in November 2022.

Future Capital Investment

Our 2022 guidance, as updated on July 27, 2022, is available on our website at cenovus.com.

The following table shows guidance for 2022:

	Capital Investment ($ millions)	Production (MBOE/d)	Throughput (Mbbls/d)
Upstream			
Oil Sands	**1,550 - 1,750**	**574 - 620**	
Conventional	**250 - 300**	**124 - 135**	
Offshore	**300 - 350**	**64 - 76**	
Downstream [1]	**1,150 - 1,250**		**530 - 580**
Corporate and Eliminations	**50 - 70**		

(1) Capital Investment includes between $500 million and $550 million for the Superior Refinery rebuild project.

Given the incident at the Toledo Refinery, U.S. Manufacturing throughput and operating costs are now expected to fall modestly outside the guidance ranges.

For the remainder of 2022, we plan to focus our Capital Investment on:

- Sustaining production in the Oil Sands segment.
- Sustaining drilling programs in the Conventional segment.
- The Superior Refinery rebuild project.
- The Terra Nova ALE project and the West White Rose project in the Offshore segment.
- Refining operations and reliability in our downstream segments.

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.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates [1]

(Average US$/bbl, unless otherwise indicated)	Nine Months Ended September 30, 2022	Percent Change	2021	Q3 2022	Q2 2022	Q3 2021
Dated Brent	**105.35**	**56**	67.73	**100.85**	113.78	73.47
WTI	**98.09**	**51**	64.82	**91.55**	108.41	70.56
Differential Dated Brent-WTI	**7.26**	**149**	2.91	**9.30**	5.37	2.91
WCS at Hardisty	**82.36**	**57**	52.31	**71.69**	95.61	56.98
Differential WTI-WCS	**15.73**	**26**	12.51	**19.86**	12.80	13.58
WCS (C$/bbl)	**105.54**	**61**	65.41	**93.53**	122.07	71.80
WCS at Nederland	**91.81**	**49**	61.58	**82.91**	103.34	65.79
Differential WTI-WCS at Nederland	**6.28**	**94**	3.24	**8.64**	5.07	4.77
Condensate (C5 @ Edmonton)	**97.24**	**51**	64.56	**87.26**	108.34	69.24
Differential WTI-Condensate (Premium)/Discount	**0.85**	**227**	0.26	**4.29**	0.07	1.32
Differential WCS-Condensate (Premium)/Discount	**(14.88)**	**(21)**	(12.25)	**(15.57)**	(12.73)	(12.26)
Average (C$/bbl)	**124.62**	**54**	80.73	**113.89**	138.30	87.18
Synthetic @ Edmonton	**102.61**	**62**	63.24	**100.34**	114.46	68.98
Differential WTI-Synthetic (Premium)/Discount	**(4.52)**	**(386)**	1.58	**(8.79)**	(6.05)	1.58
Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**126.58**	**53**	82.81	**121.52**	149.05	91.90
Chicago Ultra-low Sulphur Diesel ("ULSD")	**144.82**	**75**	82.99	**148.24**	166.62	89.96
Refining Benchmarks						
Chicago 3-2-1 Crack Spread [2]	**34.57**	**92**	18.04	**38.87**	46.50	20.67
Group 3 3-2-1 Crack Spread [2]	**34.29**	**85**	18.49	**38.57**	44.35	20.35
Renewable Identification Numbers ("RINs")	**7.45**	**7**	6.97	**8.11**	7.80	7.32
Natural Gas Prices						
AECO (C$/Mcf)	**5.56**	**79**	3.11	**5.81**	6.28	3.54
NYMEX (US$/Mcf)	**6.77**	**113**	3.18	**8.20**	7.17	4.01
Foreign Exchange Rate						
US$ per C$1 - Average	**0.780**	**(2)**	0.799	**0.766**	0.783	0.794
US$ per C$1 - End of Period	**0.730**	**(7)**	0.785	**0.730**	0.776	0.785
RMB per C$1 - Average	**5.147**	**—**	5.172	**5.246**	5.180	5.136

(1) These benchmark prices are not our realized sales prices and represent approximate values. For our average realized sales prices and realized risk management results, refer to the Netback tables in the Reportable Segments section of this MD&A.

(2) The average 3-2-1 crack spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.

Crude Oil and Condensate Benchmarks

In the third quarter of 2022, global crude oil prices remained strong despite the easing of crude oil supply and demand balances. However, weak economic sentiment and slow demand growth in China, Europe and the U.S. put downward pressure on crude oil prices. Global crude oil supply was strong due to high Saudi Arabia and United Arab Emirates production and unprecedented releases of U.S. Government Strategic Petroleum Reserves ("SPRs"). Russian supply and exports have remained consistent due to large purchases from India and China, eroding some of the geopolitical risk premium on pricing.

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.

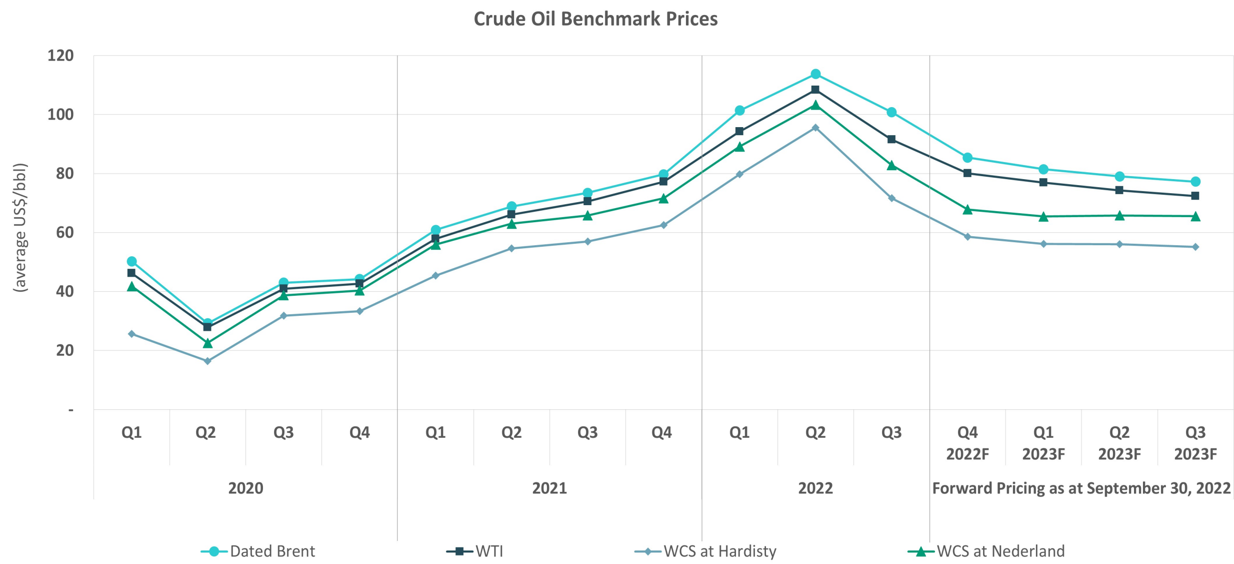
The price received for our Atlantic crude oil and Asia Pacific NGLs is primarily driven by the price of Brent. The Brent-WTI differential widened compared with 2021 and the second quarter of 2022 due to higher shipping costs and supply disruptions as a result of Russia's invasion of Ukraine.

WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WCS at Hardisty differential to WTI is a function of the quality differential of light and heavy crude and the cost of transport. In the three months ended September 30, 2022, the average WTI-WCS differential at Hardisty widened compared to 2021 and the second quarter of 2022, in part due to a wider quality differential at the U.S. Gulf Coast outlined below, as well as higher production activity in Western Canada following planned turnarounds.

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. The WTI-WCS at Nederland differential widened compared with 2021 and the second quarter of 2022, mainly attributed to reduced demand due to planned and unplanned refinery maintenance, and increased supply due to some incremental medium and heavy oil barrels into the market from OPEC+ and from the release of volume from SPRs in the U.S.

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.

Synthetic crude at Edmonton strengthened significantly in the third quarter of 2022 compared with the third quarter of 2021 as a result of widespread upgrader maintenance and strong refinery demand for light crude. The WTI-synthetic premium widened compared with the second quarter of 2022 as synthetic crudes continue to be supported by strong demand for refined products.



Blending condensate with bitumen enables our production to be transported through pipelines. Our blending ratios, calculated as diluent volumes as a percentage of total blended volumes, range from approximately 22 percent to 35 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 widened relative to WTI in the third quarter of 2022. Condensate prices globally have been pressured due to higher supply from strong refinery utilization and weak global petrochemical demand.

Refining Benchmarks

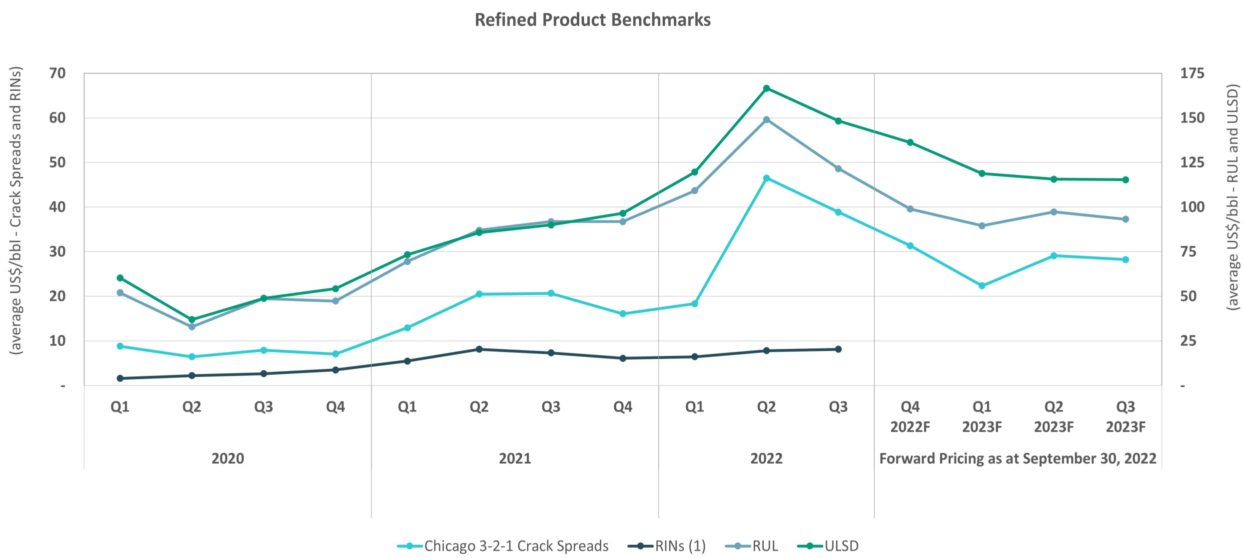
RUL and ULSD benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 market crack spread. The 3-2-1 market crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded 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 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 significantly in the third quarter of 2022 compared with the third quarter of 2021. The strength in crack spreads and refined product prices has been driven by refinery rationalization since the beginning of the pandemic, combined with low global inventories of refined products. RINs remain high as a result of a tight biofuel market, rising feedstock prices and uncertainty around policies that drive RINs demand. Average Chicago refined product prices decreased in the third quarter of 2022 compared with the historically high second quarter of 2022 but remain well above seasonal norms as product markets are still extremely tight, distillate markets in particular. The drop in the third quarter can be attributed to some slight weakening of demand amid high inflation.

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 generally 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. The market crack spreads do not precisely mirror the configuration and product output of our refineries, however they are used as a general market indicator.



(1) *There are no forward prices for RINs.*

Natural Gas Benchmarks

Average NYMEX natural gas prices increased in the third quarter of 2022, compared to the second quarter of 2022, and significantly improved compared to the third quarter of 2021 due to a rebound in U.S. domestic demand and high liquified natural gas exports, coupled with a muted supply response and strong global pricing amid Russia supply concerns. Average AECO prices decreased compared with the second quarter of 2022, and the differential between AECO and NYMEX widened compared with the second quarter of 2022 and the third quarter of 2021, due to planned and unplanned pipeline maintenance in Western Canada, limiting egress from Alberta. The price received for our Asia Pacific natural gas production is largely based on long-term contracts.

Foreign Exchange Benchmarks

A substantial amount of our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, NGLs, natural gas and refined products are determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar compared with the U.S. dollar has a negative impact on our reported revenue. In addition to our revenues being denominated in U.S. dollars, a significant portion of our long-term debt is also U.S. dollar denominated. As the Canadian dollar weakens, our U.S. dollar debt gives rise to unrealized foreign exchange losses when translated to Canadian dollars. In addition, changes in foreign exchange rates impact the translation of U.S. and Asia Pacific operations.

In the first nine months of 2022, the Canadian dollar on average weakened relative to the U.S. dollar compared with 2021, positively impacting our revenues year-over-year. The Canadian dollar weakened relative to the U.S. dollar as at September 30, 2022, compared with December 31, 2021, resulting in unrealized foreign exchange losses of $444 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. In the first nine months of 2022, the Canadian dollar on average was relatively flat compared with RMB, resulting in minimal impact on our revenues year-over-year.

Interest Rate Benchmarks

Our short-term borrowing costs and reported decommissioning liabilities are impacted by fluctuations in interest rates. An increase in interest rates could increase our net interest expense and affect how certain liabilities are measured, both of which could negatively impact our cash flow and financial results.

As at September 30, 2022, the Bank of Canada's Policy Interest Rate was 3.25 percent, increasing from 0.25 percent on December 31, 2021 due to concerns over inflation. On October 26, 2022, the rate increased 0.50 percent to 3.75 percent.

COMMODITY PRICE OUTLOOK

Crude oil prices waned in the third quarter of 2022 but remain high as supply and demand balances are tight and crude oil spare capacity is limited. Crude oil price trajectory remains uncertain and volatile amid an increasingly volatile market with unpredictable key drivers. Russian supply risks remain the markets' most significant geopolitical risk and the upcoming EU bans on Russian crude oil and products hold potential for disruption of exports. OPEC+ policy will continue to be a key driver of crude prices and the recent announcement of a cut to the group's production quotas is supportive of pricing.

We expect the general outlook for crude oil and refined product prices will be volatile and impacted by the duration and severity of the ongoing Russian invasion of Ukraine, the extent to which Russian exports are reduced by sanctions, the timing and ability of producers and governments to replace reduced supply, the release of SPRs and OPEC+ policy. Potential incremental COVID-19 outbreaks and variants, weakening economic activity, inflation and rising interest rates, and the potential for a recession remain a risk to the pace of demand growth.

In addition to the above, our commodity pricing outlook for the next 12 months is influenced by the following:

- We expect that the WTI-WCS differential will remain largely tied to global supply factors and heavy crude processing capacity as long as supply stays within Canadian crude export capacity.
- OPEC+ production is not expected to grow with the announcement of reduced quotas, but policy is subject to change based on market developments.
- Global economic activity.
- We expect market crack spreads will remain volatile as Russia is a significant exporter of refined products. Sanctions are expected to reduce supply and result in a redirection of global trade flows. Economic effects of the conflict and central bank policies could impact demand. Refining market crack spreads are likely to continue to fluctuate, adjusting for seasonal trends and refinery utilization in North America.
- We expect both Henry Hub and AECO prices to remain strong. Current fundamentals suggest a tight market will persist, but this could be offset by increased associated gas production as well as fuel switching amid high prices. Prices will continue to be impacted by weather.
- 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.

Most of our upstream crude oil production and our downstream refined products are exposed to movements in the WTI crude oil price. Natural gas and NGLs production associated with our Conventional assets provide improved upstream economic integration for the fuel, solvent and blending requirements at our Oil Sands operations.

Our refining capacity is 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. We will continue to monitor market fundamentals and optimize run rates at our refineries accordingly.

Our WTI exposure to crude differentials includes light-heavy and light-medium price differentials. The 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 differentials, which could be 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 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 – heavy oil refining capacity allows us to capture value from both the WTI-WCS differential for Canadian crude oil as well as from spreads on refined products.
- 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.

All WTI contracts related to our crude oil sales price risk management activities closed by June 30, 2022. We continue to use financial instruments to mitigate our exposure to the prices of various commodities, including some WTI contracts for exposure management unrelated to crude oil sales price risk management; and products, including associated price differentials and refining margins.

REPORTABLE SEGMENTS

UPSTREAM

OIL SANDS

In the third quarter of 2022, we:

- Delivered safe and reliable operations.
- Produced 585.0 thousand barrels of crude oil per day.
- Generated Operating Margin of $2.2 billion, an increase of $297 million compared with the third quarter of 2021 primarily due to higher average realized sales prices.
- Achieved first oil at our Spruce Lake North thermal plant. Production ramped up to approximately 10.0 thousand barrels per day by the end of the quarter.
- Invested capital of $360 million primarily on sustaining activities at Christina Lake, Foster Creek, the Lloydminster thermal assets and Sunrise.
- Achieved a Netback of $41.91 per BOE.

On August 31, 2022, we closed the purchase of the remaining 50 percent interest in Sunrise from BP Canada Energy Group ULC (“BP Canada”), giving Cenovus full ownership and further enhancing our core strength in oil sands. Total consideration included cash of $394 million net of closing adjustments, a variable payment with a maximum cumulative value of $600 million expiring after two years, and Cenovus’s 35 percent interest in the undeveloped Bay du Nord project offshore Newfoundland and Labrador.

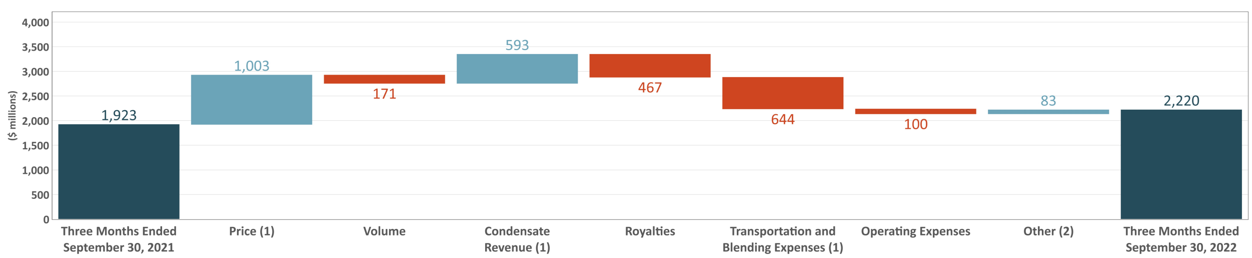
Financial Results

($ millions)	Three Months Ended September 30, 2022	2021	Nine Months Ended September 30, 2022	2021
Gross Sales (1)	**8,778**	6,117	**28,044**	16,110
Less: Royalties	**1,136**	669	**3,709**	1,462
Revenues	**7,642**	5,448	**24,335**	14,648
Expenses				
Purchased Product (1)	**1,933**	629	**4,216**	1,748
Transportation and Blending (1)	**2,758**	2,114	**9,114**	6,048
Operating	**689**	616	**2,197**	1,793
Realized (Gain) Loss on Risk Management	**42**	166	**1,468**	584
Operating Margin	**2,220**	1,923	**7,340**	4,475
Unrealized (Gain) Loss on Risk Management	**(2)**	(39)	**(59)**	194
Depreciation, Depletion and Amortization	**652**	743	**1,977**	1,982
Exploration Expense	**7**	2	**7**	15
Share of (Income) Loss from Equity-Accounted Affiliates	**—**	—	**8**	(5)
Segment Income (Loss)	**1,563**	1,217	**5,407**	2,289

(1) Prior period results were revised for a change in presentation of product swaps and certain third-party purchases used in blending and optimization activities, and to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

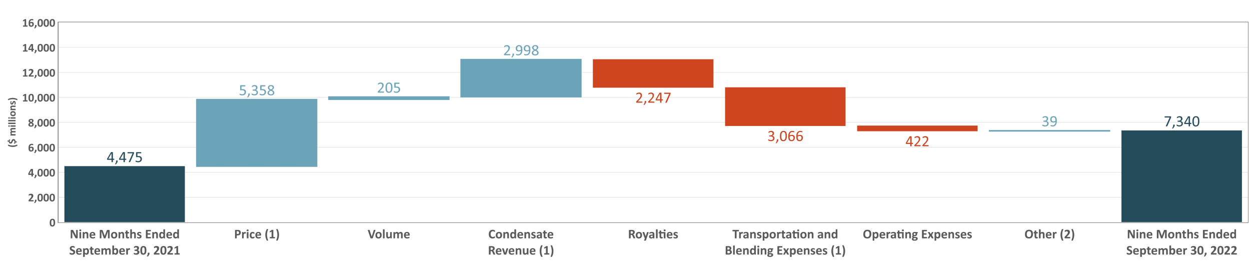
Operating Margin Variance

Three Months Ended September 30, 2022



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

Nine Months Ended September 30, 2022



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

Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	**2022**	2021
Total Sales Volumes (MBOE/d)	**578.0**	613.1	**583.8**	571.4
Total Realized Price [(1)] ($/BOE)	**84.29**	67.08	**99.78**	60.61
Crude Oil Production by Asset (Mbbls/d)				
Foster Creek	**182.4**	187.1	**189.3**	169.1
Christina Lake	**252.8**	242.5	**245.2**	232.0
Sunrise [(2)]	**30.9**	28.3	**26.8**	26.1
Lloydminster Thermal	**102.1**	98.0	**99.0**	97.3
Lloydminster Conventional Heavy Oil	**16.8**	20.5	**16.5**	20.6
Tucker [(3)]	**—**	20.6	**2.1**	21.7
Total Daily Crude Oil Production [(4)] (Mbbls/d)	**585.0**	597.0	**578.9**	566.8
Oil Sands Natural Gas [(5)] (MMcf/d)	**12.6**	11.9	**12.5**	12.7
Total Daily Production (MBOE/d)	**587.1**	599.1	**580.9**	568.9
Effective Royalty Rate (percent)	**27.8**	19.7	**25.4**	17.6
Transportation and Blending Cost [(1)] ($/BOE)	**7.72**	7.09	**7.48**	7.40
Operating Expense [(1)] ($/BOE)	**13.40**	10.90	**13.83**	11.44
Per Unit DD&A [(1)] ($/BOE)	**11.63**	11.45	**11.83**	11.37

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Represents Cenovus's 50 percent interest in Sunrise operations up to August 31, 2022. On August 31, 2022, we closed the acquisition of the remaining 50 percent interest from BP Canada.
(3) The Tucker asset sold on January 31, 2022.
(4) Oil Sands production is primarily bitumen, except for Lloydminster conventional heavy oil, which is heavy crude oil.
(5) Conventional natural gas product type.

Revenues

Price

As noted earlier, WTI benchmark for the three and nine months ended September 30, 2022, WTI benchmark prices increased, while over the same periods we saw a widening of the WTI-WCS differential. WCS at Hardisty averaged $93.53 and $105.54 in the three and nine months ended September 30, 2022, respectively (2021 – $71.80 and $65.41, respectively). WCS benchmark prices include the value of condensate used to transport heavy oil and bitumen.

Our heavy oil and bitumen production 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.

Our realized sales price, which excludes the value of condensate, was $84.29 per BOE and $99.78 per BOE in the three and nine months ended September 30, 2022, respectively (2021 – $67.08 per BOE and $60.61 per BOE, respectively). To improve our realized sales price, we sell some production to U.S. destinations. In the first nine months of 2022, we sold approximately 20 percent (2021 – 20 percent) to U.S. destinations. In the third quarter of 2022, the uplift from exporting barrels to the U.S. more than offset the impact of blending higher priced condensate purchased early in the quarter.

In the three and nine months ended September 30, 2022, gross sales included $1.9 billion and $4.0 billion, respectively (2021 – $562 million and $1.6 billion, respectively), from third-party sourced volumes which are not included in our realized price or our Netbacks. Refer to the Specified Financial Measures Advisory of this MD&A for more detail.

In the three and nine months ended September 30, 2022, gross sales included $79 million and $248 million, respectively (2021 – $39 million and $191 million, respectively) relating to construction, transportation and blending activities. These amounts are not included in our realized price or our Netbacks. Refer to the Specified Financial Measures Advisory of this MD&A for more detail.

Cenovus makes storage and transportation decisions about our marketing and transportation infrastructure, including storage and pipeline assets, to optimize product mix, delivery points, and 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 and improve cash flow stability. As announced on April 4, 2022, we suspended our crude oil sales price risk management activities related to WTI. Given the strength of our balance sheet and liquidity position, we determined these programs are no longer required to support financial resilience. All WTI contracts impacted by this decision were closed by June 30, 2022.

In the three months ended September 30, 2022, we incurred realized risk management losses of $42 million. In the first nine months of 2022, we incurred realized risk management losses of $1.5 billion, of which $431 million relates to the early liquidation of WTI positions in the second quarter. Also contributing to the losses was the settlement of benchmark prices rising above our risk management contract prices. In the three and nine months ended September 30, 2022, we recorded unrealized gains of $2 million and $59 million, respectively, on our crude oil and condensate financial instruments.

Production Volumes

Oil Sands crude oil production was 585.0 thousand barrels per day and 578.9 thousand barrels per day in the three and nine months ended September 30, 2022, respectively (2021 – 597.0 thousand barrels per day and 566.8 thousand barrels per day, respectively).

We sold the Tucker asset on January 31, 2022, resulting in decreased production of 19.6 thousand barrels per day in the first nine months of 2022 compared with 2021.

Production at Foster Creek decreased marginally in the three months ended September 30, 2022, compared with 2021, due to planned maintenance and an unplanned outage during the quarter, and natural declines. In the first nine months of 2022, production increased 20.2 thousand barrels per day compared with 2021, as we completed a planned turnaround at Foster Creek in the second quarter of 2021.

Production at Christina Lake increased 10.3 thousand barrels per day and 13.2 thousand barrels per day in the three and nine months ended September 30, 2022, respectively, compared with 2021. We completed a planned turnaround during the second quarter of 2022, however production impacts were offset by incremental production added from redevelopment wells drilled in 2022 and the last half of 2021.

Sunrise production increased slightly in the third quarter of 2022, compared with 2021, as we closed the Sunrise Acquisition on August 31, 2022. Year-to-date, production was relatively flat compared with 2021.

The Lloydminster thermal assets continued their strong performance. Production increased slightly as the Spruce Lake North thermal plant achieved first oil in August, and production ramped up to approximately 10.0 thousand barrels per day by the end of the quarter. Lloydminster conventional heavy oil production decreased marginally in the three and nine months ended September 30, 2022, compared with 2021, as wells were shut-in to meet new emissions regulations in Alberta.

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 and Sunrise) 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 calculated as sales revenues less diluent costs, transportation costs, and allowed operating and capital costs.

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

For our Saskatchewan assets, Lloydminster thermal and Lloydminster conventional heavy oil, royalty calculations are based on an annual rate that is applied to each project, which includes 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. In the three and nine months ended September 30, 2022, royalties were $1.1 billion and $3.7 billion, respectively (2021 – $669 million and $1.5 billion, respectively). The increases were mainly due to higher net revenue for royalty purposes as a result of higher realized pricing.

Expenses

Transportation and Blending

In the third quarter of 2022, blending costs increased $590 million to $2.3 billion compared with 2021. In the first nine months of 2022, blending costs rose $3.0 billion to $7.9 billion compared with 2021. The increases were largely due to higher condensate prices.

Transportation costs increased $54 million to $434 million in the third quarter of 2022 compared with 2021. In the first nine months of 2022, transportation costs rose $71 million to $1.2 billion compared with 2021. The increases were primarily due to increased tariff rates, partially offset by lower sales volumes.

Per-unit Transportation Expenses

Transportation costs were $7.72 per BOE and $7.48 per BOE in the three and nine months ended September 30, 2022, respectively (2021 – $7.09 per BOE and $7.40 per BOE, respectively).

At Foster Creek, per-unit transportation costs increased 18 percent and decreased two percent to $11.96 per barrel and $10.71 per barrel in the three and nine months ended September 30, 2022, respectively. The increase in the third quarter of 2022 compared with 2021 is primarily due to lower sales volumes, partially offset by reduced reliance on rail. Year-to-date, the decrease is mainly due to higher sales volumes combined with reduced reliance on rail, partially offset by increased tariff rates. In the three and nine months ended September 30, 2022, we shipped 40 percent (2021 – 40 percent and 35 percent, respectively), of our volumes from Foster Creek to U.S. destinations. Of those, we shipped less than five percent of our volumes by rail in the three and nine months ended September 30, 2022 (2021 – 15 percent).

At Christina Lake, transportation costs were $6.02 per barrel and $6.37 per barrel in the three and nine months ended September 30, 2022, respectively (2021 – $5.74 and $6.15, respectively). The slight increase is due to increased tariff rates.

At Sunrise, transportation costs in the three and nine months ended September 30, 2022, were $13.17 per barrel and $12.96 per barrel, respectively (2021 – $14.01 per barrel and $12.90 per barrel, respectively). In the three and nine months ended September 30, 2022 we shipped 40 percent and 50 percent, respectively (2021 – 60 percent and 50 percent, respectively), of our volumes from Sunrise to U.S. destinations.

At our Lloydminster thermal, Tucker and Lloydminster conventional heavy oil assets, transportation costs in the three and nine months ended September 30, 2022, were $3.57 per barrel and $3.45 per barrel, respectively (2021 – $3.80 per barrel and $4.27 per barrel, respectively). The Tucker asset was sold on January 31, 2022. Per-unit transportation costs decreased in the first nine months of 2022 compared with 2021, as we stopped shipping these barrels to U.S. destinations after the first quarter of 2021 as we optimized our pipeline capacity after the Arrangement.

Operating

Primary drivers of our operating expenses in the three and nine months ended September 30, 2022 were fuel, chemical, electricity, workforce, workovers, and repairs and maintenance. Total and per-unit operating expenses increased largely due to higher fuel costs as a result of higher natural gas prices. AECO benchmark natural gas prices increased 64 percent and 79 percent in the three and nine months ended September 30, 2022, respectively, compared with 2021. In addition, total and per-unit operating expenses increased due to higher electricity costs and inflationary pressures on chemical costs. Chemical costs and electricity costs are also influenced by rising crude oil and natural gas benchmark prices. Overall cost pressures are being managed by securing long-term contracts, working with vendors and purchasing long-lead items to mitigate future cost escalations.

Foster Creek per-unit non-fuel costs increased in the three months ended September 30, 2022, primarily due to higher electricity and chemical costs, and costs related to operational outages and planned maintenance during the quarter, combined with lower sales volumes. Year-to-date, per-unit non-fuel costs increased due to the same factors impacting the third quarter of 2022, partially offset by higher sales volumes.

Christina Lake per unit non-fuel costs increased in the three months ended September 30, 2022, mainly due to higher repairs and maintenance costs, partially offset by higher sales volumes. Year-to-date, per-unit non-fuel costs were relatively flat as higher sales volumes in 2022 offset the impact of costs related to the turnaround in the second quarter of 2022.

Per-unit non-fuel costs at our other Oil Sands assets increased in the quarter mainly due to costs related to the start up of the Spruce Lake North project and ramp up of volume through the quarter. Year-to-date, the increase was primarily due to higher chemical costs and workover activity at Sunrise and the Lloydminster thermal assets in the second quarter of 2022, partially offset by costs related to the planned turnaround at Sunrise in the second quarter of 2021.

Unit Operating Expenses [1]

($/BOE)	Three Months Ended September 30, 2022	Percent Change	2021	Nine Months Ended September 30, 2022	Percent Change	2021
Foster Creek						
Fuel	**5.91**	**42**	4.15	**5.77**	**47**	3.92
Non-Fuel	**7.55**	**25**	6.05	**7.19**	**3**	6.98
Total	**13.46**	**32**	10.20	**12.96**	**19**	10.90
Christina Lake						
Fuel	**4.46**	**26**	3.53	**5.00**	**55**	3.23
Non-Fuel	**4.73**	**10**	4.30	**5.01**	**4**	4.81
Total	**9.19**	**17**	7.83	**10.01**	**25**	8.04
Other Oil Sands [2]						
Fuel	**5.32**	**9**	4.89	**7.19**	**60**	4.50
Non-Fuel	**14.93**	**33**	11.20	**14.33**	**17**	12.23
Total	**20.25**	**26**	16.09	**21.52**	**29**	16.73
Total	**13.40**	**23**	10.90	**13.83**	**21**	11.44

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Includes Sunrise, Tucker, Lloydminster thermal and Lloydminster conventional heavy oil assets. The Tucker asset was sold on January 31, 2022.

Netbacks

($/BOE)	Three Months Ended September 30, 2022	2021	Nine Months Ended September 30, 2022	2021
Sales Price [1]	**84.29**	67.08	**99.78**	60.61
Royalties [1]	**21.26**	11.84	**23.20**	9.36
Transportation [1]	**7.72**	7.09	**7.48**	7.40
Operating Expenses [1]	**13.40**	10.90	**13.83**	11.44
Netback [2]	**41.91**	37.25	**55.27**	32.41

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

DD&A

In the three and nine months ended September 30, 2022, DD&A was $652 million and $2.0 billion, respectively (2021 – $743 million and $2.0 billion, respectively). The decrease was mainly due to asset write-downs booked in the third quarter of 2021. The average depletion rate for the three and nine months ended September 30, 2022, was $11.63 per BOE and 11.83 per BOE, respectively (2021 – $11.45 per BOE and $11.37 per BOE, respectively).

CONVENTIONAL

In the third quarter of 2022, we:

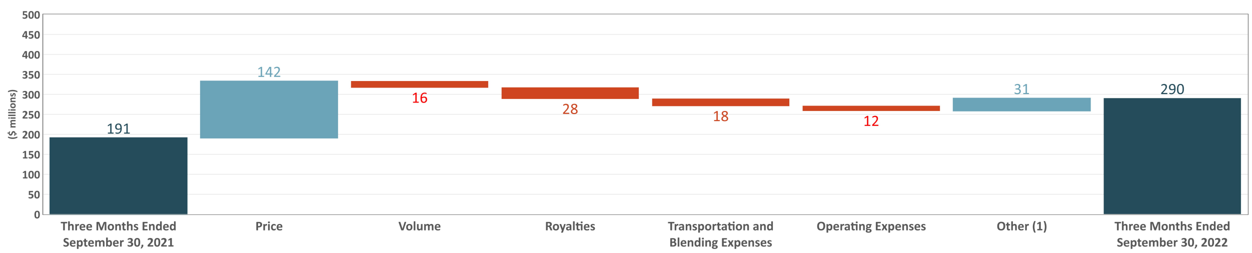
- Delivered safe and reliable operations.
- Generated Operating Margin of $290 million, an increase of $99 million compared with the third quarter of 2021, largely due to higher average realized sales prices.
- Invested capital of $67 million focused on the ramp up of the drilling program and the remaining tie-in of the previous development program.
- Achieved a Netback of $24.06 per BOE.

Financial Results

($ millions)	Three Months Ended September 30, 2022	2021	Nine Months Ended September 30, 2022	2021
Gross Sales	**1,010**	833	**3,201**	2,235
Less: Royalties	**68**	40	**228**	103
Revenues	**942**	793	**2,973**	2,132
Expenses				
Purchased Product	**464**	445	**1,460**	1,113
Transportation and Blending	**38**	20	**106**	57
Operating	**141**	135	**403**	417
Realized (Gain) Loss on Risk Management	**9**	2	**17**	2
Operating Margin	**290**	191	**987**	543
Unrealized (Gain) Loss on Risk Management	**8**	9	**7**	10
Depreciation, Depletion and Amortization	**103**	99	**282**	309
Exploration Expense	**—**	—	**1**	(3)
Segment Income (Loss)	**179**	83	**697**	227

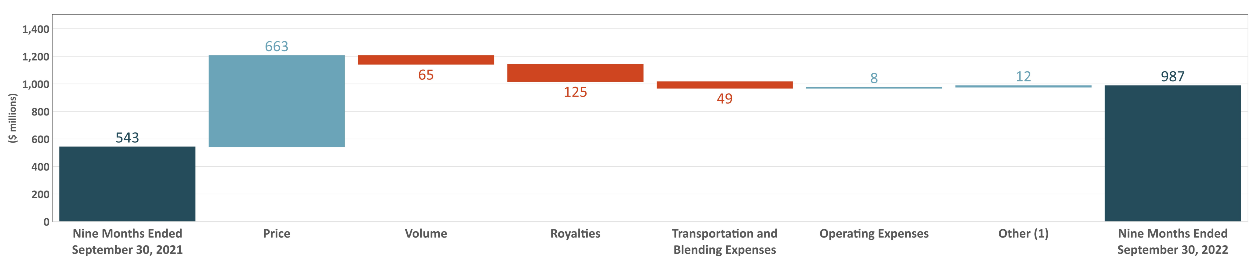
Operating Margin Variance

Three Months Ended September 30, 2022



(1) Reflects Operating Margin related to processing activities.

Nine Months Ended September 30, 2022



(1) Reflects Operating Margin from processing facilities.

Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	**2022**	2021
Total Sales Volumes (MBOE/d)	**126.2**	131.4	**128.0**	136.2
Total Realized Price [1] ($/BOE)	**44.07**	31.28	**48.17**	28.76
Light Crude Oil ($/bbl)	**132.08**	87.31	**125.99**	71.98
NGLs ($/bbl)	**55.80**	47.37	**61.98**	39.79
Conventional Natural Gas ($/Mcf)	**5.93**	3.85	**6.48**	3.69
Production by Product				
Light Crude Oil (Mbbls/d)	**6.9**	8.7	**7.8**	8.8
NGLs (Mbbls/d)	**19.9**	22.8	**23.0**	26.7
Conventional Natural Gas (MMcf/d)	**596.1**	603.2	**583.1**	605.4
Total Daily Production (MBOE/d)	**126.2**	132.0	**128.0**	136.4
Conventional Natural Gas Production (percentage of total)	**79**	76	**76**	74
Crude Oil and NGLs Production (percentage of total)	**21**	24	**24**	26
Effective Royalty Rate (percent)	**15.9**	11.2	**15.3**	10.2
Transportation Costs [1] ($/BOE)	**2.43**	1.64	**2.85**	1.54
Operating Expense [1] ($/BOE)	**11.77**	10.41	**11.03**	10.57
Per Unit DD&A [1] ($/BOE)	**8.51**	7.98	**8.23**	8.12

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

Revenues

Price

Our total realized sales price increased in the three and nine months ended September 30, 2022, due to higher crude oil and natural gas benchmark prices.

In the three and nine months ended September 30, 2022, gross sales included $464 million and $1.5 billion, respectively (2021 – $445 million and $1.1 billion, 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, 2022, revenues included amounts relating to processing and transportation activities undertaken for third-parties of $34 million and $58 million, respectively (2021 – $10 million and $53 million, respectively), which are not included in our per-unit pricing metrics or our Netbacks.

Production Volumes

Production volumes decreased in the three and nine months ended September 30, 2022, mainly due to asset sales in the first quarter of 2022 and the second half of 2021, and planned maintenance in the third quarter of 2022. The production decrease is partially offset by 29 net new wells brought on production during the year, combined with production from well reactivations and workover activity.

Royalties

The Conventional assets are subject to royalty regimes in Alberta and British Columbia. Total royalties and effective royalty rates increased in the three and nine months ended September 30, 2022, primarily due to higher realized pricing.

Expenses

Transportation

Our transportation costs reflect charges for the movement of crude oil, NGLs and natural gas from the point of production to where the product is sold. Transportation costs increased by $18 million and $49 million in the three and nine months ended September 30, 2022, respectively, compared with 2021. Per-unit transportation costs averaged $2.43 per BOE and $2.85 per BOE in the three and nine months ended September 30, 2022, respectively (2021 – $1.64 per BOE and $1.54 per BOE, respectively).

Operating

Primary drivers of our operating expenses in the three and nine months ended September 30, 2022, were workforce, repairs and maintenance, electricity, property taxes and lease costs. Operating expenses per BOE in the three and nine months ended September 30, 2022, increased compared with 2021, primarily due to higher electricity costs. Total operating expenses in the three and nine months ended September 30, 2022, were relatively flat due to the same factors that impacted operating expenses per BOE, offset by lower sales volumes.

Netbacks

	Three Months Ended September 30,		Nine Months Ended September 30,	
($/BOE)	**2022**	2021	**2022**	2021
Sales Price (1)	**44.07**	31.28	**48.17**	28.76
Royalties (1)	**5.81**	3.32	**6.49**	2.77
Transportation and Blending (1)	**2.43**	1.64	**2.85**	1.54
Operating Expenses (1)	**11.77**	10.41	**11.03**	10.57
Netback (2)	**24.06**	15.91	**27.80**	13.88

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

DD&A

The average depletion rate for the three and nine months ended September 30, 2022, was $8.51 per BOE and $8.23 per BOE, respectively (2021 – $7.98 per BOE and $8.12 per BOE).

In the three and nine months ended September 30, 2022, total Conventional DD&A was $103 million and $282 million, respectively (2021 – $99 million and $309 million, respectively). The year-to-date decrease was due to asset dispositions in the first quarter of 2022 and the second half of 2021.

OFFSHORE

In the third quarter of 2022, we:

- Delivered safe and reliable operations.
- Generated Operating Margin of $339 million, an increase of $11 million compared with the third quarter of 2021, largely due to higher average realized sales prices, partially offset by increased operating expenses and lower sales volumes.
- Earned a Netback of $66.81 per BOE.
- Invested capital of $81 million mainly for the Terra Nova ALE and the West White Rose projects in the Atlantic region.

On May 31, 2022, Cenovus and our partners announced we reached an agreement to restart the West White Rose project in the Atlantic region. The project is expected to restart in 2023. First oil is anticipated in the first half of 2026, with peak production anticipated to reach approximately 80 thousand barrels per day, 45 thousand barrels per day net to Cenovus, by 2029. Contributing to the decision to restart the project is an amended royalty structure with the Government of Newfoundland and Labrador which provides safeguards to the project's economics in periods of low commodity prices. The remaining capital required to achieve first oil is expected to be approximately $2.0 billion to $2.3 billion net to Cenovus, of which we expect to spend an estimated $90 million in 2022. The project is around 65 percent complete. Following our decision to restart the project, we invested approximately $50 million as at September 30, 2022.

The Terra Nova ALE project remains underway in Spain, and the FPSO is anticipated to return to the field before the end of 2022.

At our equity-accounted assets in Indonesia, we drilled and completed the remaining three MDA field development wells planned for the year (five planned). We expect first gas production from the MDA field in November 2022. We achieved first gas production at the MBH field in October. At the MAC field, production facilities are under construction and we expect to start drilling three development wells in the fourth quarter of 2022.

Financial Results

($ millions)	Three Months Ended September 30, 2022 Asia Pacific	Atlantic	Offshore	2021 Asia Pacific	Atlantic	Offshore
Revenues						
Gross Sales	**337**	**113**	**450**	336	68	404
Less: Royalties	**20**	**2**	**22**	20	4	24
	317	**111**	**428**	316	64	380
Expenses						
Transportation and Blending	**—**	**4**	**4**	—	3	3
Operating	**32**	**53**	**85**	28	21	49
Operating Margin [(1)]	**285**	**54**	**339**	288	40	328
Depreciation, Depletion and Amortization			**132**			127
Exploration Expense			**66**			3
(Income) Loss from Equity-Accounted Affiliates			**(9)**			(12)
Segment Income (Loss)			**150**			210

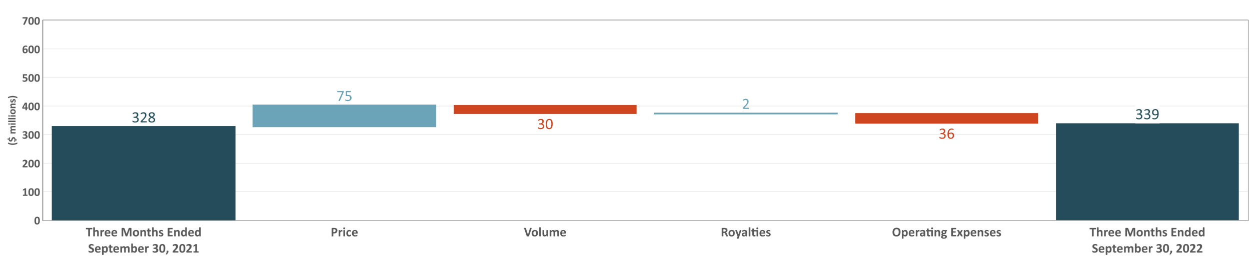
(1) *Asia Pacific and Atlantic Operating Margin are Non-GAAP financial measures. See the Specified Financial Measures Advisory of this MD&A.*

($ millions)	Nine Months Ended September 30, 2022 Asia Pacific	Atlantic	Offshore	2021 Asia Pacific	Atlantic	Offshore
Revenues						
Gross Sales	**1,083**	**492**	**1,575**	965	297	1,262
Less: Royalties	**60**	**(4)**	**56**	53	21	74
	1,023	**496**	**1,519**	912	276	1,188
Expenses						
Transportation and Blending	**—**	**12**	**12**	—	10	10
Operating	**88**	**146**	**234**	74	92	166
Operating Margin [(1)]	**935**	**338**	**1,273**	838	174	1,012
Depreciation, Depletion and Amortization			**441**			369
Exploration Expense			**91**			3
(Income) Loss from Equity-Accounted Affiliates			**(19)**			(36)
Segment Income (Loss)			**760**			676

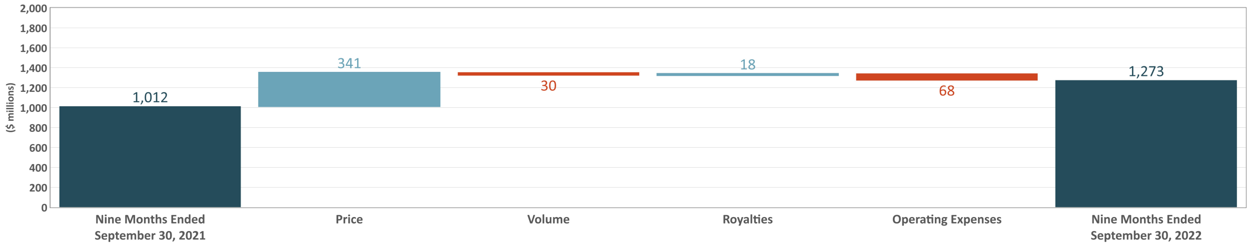
(1) Asia Pacific and Atlantic Operating Margin are Non-GAAP financial measures. See the Specified Financial Measures Advisory of this MD&A.

Operating Margin Variance

Three Months Ended September 30, 2022



Nine Months Ended September 30, 2022



Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	**2022**	2021
Total Sales Volumes (MBOE/d)	**63.3**	67.6	**70.9**	72.1
Atlantic	**7.8**	7.8	**12.6**	12.6
Asia Pacific [(1)]	**55.5**	59.8	**58.3**	59.5
Total Realized Price [(2)] ($/BOE)	**88.02**	74.55	**91.32**	72.25
Atlantic - Light Crude Oil ($/bbl)	**158.42**	94.26	**142.96**	85.93
Asia Pacific [(1)] ($/BOE)	**78.19**	71.99	**80.16**	69.36
NGLs ($/bbl)	**108.39**	81.82	**113.04**	74.73
Conventional Natural Gas ($/Mcf)	**11.62**	11.56	**11.88**	11.32
Production by Product				
Atlantic - Light Crude Oil (Mbbls/d)	**9.1**	13.9	**12.0**	15.3
Asia Pacific [(1)]				
NGLs (Mbbls/d)	**12.2**	12.7	**12.4**	12.6
Conventional Natural Gas (MMcf/d)	**260.0**	282.8	**275.3**	281.4
Asia Pacific Total (MBOE/d)	**55.5**	59.8	**58.3**	59.5
Total Daily Production (MBOE/d)	**64.6**	73.7	**70.3**	74.8
Effective Royalty Rate (percent)				
Atlantic	**1.8**	5.9	**(0.8)**	7.0
Asia Pacific [(1)]	**11.1**	8.0	**11.7**	6.9
Operating Expense [(2)] ($/BOE)	**12.55**	9.12	**12.24**	9.38
Atlantic	**47.23**	29.44	**36.79**	26.62
Asia Pacific [(1)]	**7.70**	6.49	**6.94**	5.73
Per Unit DD&A [(2)] ($/BOE)	**30.89**	26.75	**30.29**	25.96

(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 in the consolidated financial statements.
(2) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Revenues

Price

The price we receive for natural gas sold in Asia is set under long-term contracts. Our realized sales price on light crude oil and NGLs increased in the three and nine months ended September 30, 2022, compared with 2021, primarily due to higher Brent benchmark pricing.

Production and Sales Volumes

Asia Pacific production decreased 4.3 thousand BOE per day in the third quarter of 2022 compared with 2021, due to the planned maintenance at block 29/26 in China that began in the second quarter and was completed in the third quarter, combined with changes to contracts at Liwan 3-1 and Liuhua 29-1 resulting in a net decrease in production. The decrease was offset by planned maintenance in China in the third quarter of 2021.

Asia Pacific production in the first nine months of 2022 decreased slightly compared with 2021, due to the same factors as discussed above combined with the completion of planned maintenance at the FPSO in Indonesia in the first quarter of 2022.

Atlantic production decreased 4.8 thousand barrels per day and 3.3 thousand barrels per day in the three and nine months ended September 30, 2022, respectively, compared with 2021. The decrease was due to the working interest restructuring on the White Rose fields in the second quarter of 2022, annual planned maintenance at the SeaRose FPSO completed during the quarter and natural declines. In 2021, the annual planned maintenance started late in the third quarter and was completed in the fourth quarter. Light oil from production at the White Rose fields 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.

Royalties

Royalty rates in China and Indonesia are governed by production sharing contracts in which production is shared with the Chinese and Indonesian governments. The effective royalty rates for the three and nine months ended September 30, 2022 were 11.1 percent and 11.7 percent, respectively (2021 – 8.0 percent and 6.9 percent, respectively). The increases in the effective royalty rates in 2022 are due to the full recovery of development costs at the Madura-BD gas project in the third quarter of 2021.

Royalties at the White Rose fields are based on an amended agreement between our working interest partners and the Government of Newfoundland and Labrador. For 2022, retroactive to January 1, 2022, we pay a basic royalty of 1.0 percent of gross sales from the White Rose fields and 1.0 percent of gross sales from the satellite extensions. The effective royalty rates for the three and nine months ended September 30, 2022 were 1.8 percent and negative 0.8 percent, respectively (2021 – 5.9 percent and 7.0 percent, respectively). The second quarter of 2022 includes a year-to-date adjustment to reflect the amended royalty regime.

Expenses

Operating

Primary drivers of our Asia Pacific operating expenses in the first nine months of 2022 were repairs and maintenance, insurance and workforce. Total and per-unit operating expenses increased largely due to planned maintenance at block 29/26 in China in the second and third quarter.

Primary drivers of our Atlantic operating expenses in the first nine months of 2022 were repairs and maintenance, workforce, vessel costs and helicopter costs. Total and per-unit operating expenses increased mainly due to continued preparations for the Terra Nova FPSO’s return to field and a higher working interest in the Terra Nova field. The increase in total operating expenses was offset by the working interest restructuring on the White Rose fields in the second quarter of 2022.

Transportation

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

Exploration Expense

In the three and nine months ended September 30, 2022, we recorded exploration expense of $66 million and $91 million, respectively, primarily due to a $58 million write-off related to our decision not to pursue development at block 15/33 in China.

Netbacks

	Three Months Ended September 30, 2022			
($/BOE, except where indicated)	**China**	**Indonesia** [(1)]	**Atlantic** ($/bbl)	**Total Offshore**
Sales Price [(2)]	**80.68**	**66.97**	**158.42**	**88.02**
Royalties [(2)]	**4.63**	**26.80**	**2.86**	**7.94**
Transportation and Blending [(2)]	**—**	**—**	**5.86**	**0.72**
Operating Expenses [(2)]	**6.73**	**12.05**	**47.23**	**12.55**
Netback [(3)]	**69.32**	**28.12**	**102.47**	**66.81**

	Three Months Ended September 30, 2021			
($/BOE, except where indicated)	China	Indonesia [(1)]	Atlantic ($/bbl)	Total Offshore
Sales Price [(2)]	73.32	65.39	94.26	74.55
Royalties [(2)]	4.39	12.78	5.60	5.77
Transportation and Blending [(2)]	—	—	3.99	0.46
Operating Expenses [(2)]	5.87	9.55	29.44	9.12
Netback [(3)]	63.06	43.06	55.23	59.20

(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 in the consolidated financial statements.
(2) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(3) Contains a Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

	Nine Months Ended September 30, 2022			
($/BOE, except where indicated)	**China**	**Indonesia** [(1)]	**Atlantic** ($/bbl)	**Total Offshore**
Sales Price [(2)]	**81.70**	**72.50**	**142.96**	**91.32**
Royalties [(2)]	**4.50**	**33.51**	**(1.16)**	**7.47**
Transportation and Blending [(2)]	**—**	**—**	**3.54**	**0.63**
Operating Expenses [(2)]	**5.71**	**13.06**	**36.79**	**12.24**
Netback [(3)]	**71.49**	**25.93**	**103.79**	**70.98**

	Nine Months Ended September 30, 2021			
($/BOE, except where indicated)	China	Indonesia [(1)]	Atlantic ($/bbl)	Total Offshore
Sales Price [(2)]	70.61	62.71	85.93	72.25
Royalties [(2)]	3.94	9.11	6.02	4.98
Transportation and Blending [(2)]	—	—	2.78	0.49
Operating Expenses [(2)]	5.18	8.67	26.62	9.38
Netback [(3)]	61.49	44.93	50.51	57.40

(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 in the consolidated financial statements.
(2) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(3) Contains a Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

DD&A

In the three and nine months ended September 30, 2022, total Offshore DD&A was $132 million and $441 million, respectively (2021 – $127 million and $369 million, respectively). The average depletion rate in the three and nine months ended September 30, 2022 was $30.89 per BOE and $30.29 per BOE, respectively (2021 – $26.75 per BOE and $25.96 per BOE, respectively).

DOWNSTREAM

CANADIAN MANUFACTURING

In the third quarter of 2022, we:

- Delivered safe operations.
- Averaged combined crude utilization of 89 percent at the Lloydminster Upgrader and Lloydminster Refinery, as we returned to full operations after completing planned turnarounds in the second quarter.
- Generated Operating Margin of $249 million, an increase of $119 million compared with the third quarter of 2021, primarily due to a higher upgrading differential and higher asphalt pricing, partially offset by lower sales volumes.

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2022**	2021	**2022**	2021
Revenues	**1,478**	1,215	**4,043**	3,109
Purchased Product	**1,092**	986	**3,192**	2,424
Gross Margin [1]	**386**	229	**851**	685
Expenses				
Transportation and Blending	**3**	—	**3**	—
Operating	**134**	99	**438**	284
Operating Margin	**249**	130	**410**	401
Depreciation, Depletion and Amortization	**37**	41	**143**	127
Segment Income (Loss)	**212**	89	**267**	274

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

Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	**2022**	2021
Crude Oil Throughput Capacity (Mbbls/d)	**110.5**	110.5	**110.5**	110.5
Lloydminster Upgrader (Mbbls/d)	**81.5**	81.5	**81.5**	81.5
Lloydminster Refinery (Mbbls/d)	**29.0**	29.0	**29.0**	29.0
Heavy Crude Oil Throughput (Mbbls/d)	**98.5**	108.3	**92.5**	106.0
Lloydminster Upgrader (Mbbls/d)	**71.3**	81.2	**68.8**	78.6
Lloydminster Refinery (Mbbls/d)	**27.2**	27.1	**23.7**	27.4
Crude Utilization [1] (percent)	**89**	98	**84**	96
Refined Products Output (Mbbls/d)	**99.2**	109.2	**92.9**	107.1
Sales Volumes [2] (Mbbls/d)	**111.5**	125.5	**99.7**	115.3
Upgrading Differential [3]	**39.36**	17.00	**28.69**	15.84
Refining Margin [4] ($/bbl)	**38.78**	17.57	**29.37**	16.78
Lloydminster Upgrader ($/bbl)	**38.17**	16.93	**30.08**	16.91
Lloydminster Refinery ($/bbl)	**40.39**	19.29	**27.34**	16.58
Unit Operating Expense [5] ($/bbl)	**11.72**	7.38	**13.95**	7.39
Crude-by-Rail Operations				
Volumes Loaded [6] (Mbbls/d)	**1.4**	14.3	**1.5**	13.0
Ethanol Production (thousands of litres/d)	**812.2**	774.0	**769.6**	607.4

(1) Based on crude oil throughput volumes and results of operations at the Lloydminster Upgrader and Lloydminster Refinery.
(2) From the Lloydminster Upgrader and Lloydminster Refinery.
(3) Based on benchmark price differential between heavy oil feedstock and synthetic crude.
(4) Contains a Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A. Revenues from the Lloydminster Upgrader for the three and nine months ended September 30, 2022, were $951 million and $2.7 billion, respectively (2021 – $684 million and $1.8 billion, respectively). Revenues from the Lloydminster Refinery for the three and nine months ended September 30, 2022, were $600 million and $1.0 billion, respectively (2021 – $278 million and $611 million, respectively).
(5) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(6) Volumes transported outside of Alberta, Canada.

In the three months ended September 30, 2022, crude oil throughput decreased 9.8 thousand barrels per day compared with 2021 due to temporary unplanned outages at the Lloydminster Upgrader and Lloydminster Refinery during the quarter. Year-to-date, crude oil throughput decreased 13.5 thousand barrels per day compared with 2021 due to planned turnarounds at the Lloydminster Upgrader and Lloydminster Refinery completed in the second quarter of 2022. In addition, there were unplanned maintenance outages at the Lloydminster Upgrader in the first quarter of 2022.

Revenues and Gross Margin

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

Lloydminster Refinery operations process blended heavy crude oil into asphalt and industrial products. Revenues are dependent on market prices for asphalt and other industrial products. The gross margin is largely dependent on asphalt and industrial products pricing 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.

The Lloydminster Upgrader sources crude oil feedstock primarily from our Lloydminster thermal production. The Lloydminster Refinery sources crude oil feedstock from our Lloydminster thermal and Lloydminster conventional heavy oil production.

In the three and nine months ended September 30, 2022, revenues increased by $263 million and $934 million, respectively, to $1.5 billion and $4.0 billion, respectively, mainly due to higher synthetic crude benchmark prices and higher asphalt and industrial products prices, partially offset by lower sales volumes as a result of the unplanned outages. The year-to-date increase was partially offset by lower sales volumes from the Lloydminster Upgrader and Lloydminster Refinery due to the planned turnarounds in the second quarter.

Gross margin increased $157 million quarter-over-quarter to $386 million in the third quarter of 2022 primarily due to a higher upgrading differential and higher asphalt and industrial product prices, partially offset by lower sales volumes.

Gross margin increased $166 million in the first nine months of 2022 compared with 2021, as a higher upgrading differential and higher asphalt and industrial product prices were offset by the approximately $55 million settlement of a take-or-pay contract in 2021 and lower sales volumes.

See the Specified Financial Measures Advisory of this MD&A for revenues and gross margin by asset.

Operating Expenses

Primary drivers of operating expenses in the third quarter of 2022 were repairs and maintenance, workforce and energy costs. Total and per-unit operating costs increased in the third quarter of 2022 compared with 2021 primarily due to operational outages, combined with higher energy costs and inflationary pressures on maintenance, workforce, and chemical costs. Year-to-date, total and per-unit operating costs increased due to the same factors impacting the third quarter, combined with planned turnarounds completed in the second quarter of 2022 at the Lloydminster Upgrader and Lloydminster Refinery. In addition, per-unit operating expenses increased due to lower crude oil throughput volumes.

DD&A

For the three and nine months ended September 30, 2022, Canadian Manufacturing DD&A was $37 million and $143 million, respectively (2021 – $41 million and $127 million, respectively).

U.S. MANUFACTURING

In the third quarter of 2022, we:

- Announced our intent to purchase the remaining 50 percent interest in the Toledo Refinery from BP.
- Completed a significant planned turnaround at the non-operated Toledo Refinery, which was completed by early August. The Toledo Refinery remains shut down following an incident on September 20, 2022.
- Commenced a planned turnaround at the Wood River Refinery in September, which was completed in October.
- Continued preparations for the Superior Refinery restart.
- Had crude utilization of 87 percent and crude oil throughput of 435.0 thousand barrels per day.
- Generated Operating Margin of $244 million, an increase of $122 million compared with 2021 largely due to significantly higher market crack spreads.
- Invested capital of $300 million focused primarily on the Superior Refinery rebuild, and refining reliability initiatives at the Wood River, Borger and Toledo refineries.

Financial Results

($ millions)	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
Revenues	**8,719**	5,723	**23,702**	13,889
Purchased Product	**7,944**	5,171	**20,365**	12,320
Gross Margin [(1)]	**775**	552	**3,337**	1,569
Expenses				
Operating	**608**	413	**1,757**	1,212
Realized (Gain) Loss on Risk Management	**(77)**	17	**120**	48
Operating Margin	**244**	122	**1,460**	309
Unrealized (Gain) Loss on Risk Management	**(8)**	5	**(22)**	38
Depreciation, Depletion and Amortization	**91**	103	**259**	320
Segment Income (Loss)	**161**	14	**1,223**	(49)

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

Select Operating Results

	Three Months Ended September 30, 2022	Three Months Ended September 30, 2021	Nine Months Ended September 30, 2022	Nine Months Ended September 30, 2021
Crude Oil Throughput Capacity (Mbbls/d)	**502.5**	502.5	**502.5**	502.5
Lima Refinery	**175.0**	175.0	**175.0**	175.0
Toledo Refinery [(1)]	**80.0**	80.0	**80.0**	80.0
Wood River and Borger Refineries [(1)]	**247.5**	247.5	**247.5**	247.5
Crude Oil Throughput (Mbbls/d)	**435.0**	445.8	**405.3**	415.0
Lima Refinery	**164.2**	163.1	**153.5**	149.6
Toledo Refinery [(1)]	**46.6**	71.0	**48.5**	68.3
Wood River and Borger Refineries [(1)]	**224.2**	211.7	**203.3**	197.1
Throughput by Product (Mbbls/d)				
Heavy Crude Oil	**145.2**	143.8	**135.2**	133.0
Light and Medium Crude Oil	**289.8**	302.0	**270.1**	282.0
Crude Utilization (percent)	**87**	89	**81**	83
Sales Volumes (Mbbls/d)	**453.5**	462.8	**425.8**	431.6
Refining Margin [(2)(3)] ($/bbl)	**18.98**	13.45	**29.94**	13.84
Unit Operating Expense [(3)(4)] ($/bbl)	**14.90**	10.03	**15.77**	10.69

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

During the three and nine months ended September 30, 2022, crude utilization was 87 percent and 81 percent, respectively (2021 – 89 percent and 83 percent, respectively). We had strong operational performance in the third quarter of 2022 at the Lima, Wood River and Borger refineries, compared with temporary unplanned outages at the Wood River and Borger refineries in the third quarter of 2021. These positive impacts on throughput were offset by the planned turnaround at the Toledo Refinery completed by early August, the incident at the Toledo Refinery in September 2022, and the planned fall turnaround at the Wood River Refinery which commenced in the third quarter of 2022 and was completed in October. Year-over-year, crude utilization was relatively consistent, as the impact of the turnarounds and unplanned outages in 2022, were offset by higher throughput due to improved market conditions in 2022 and unplanned outages in 2021.

The Lima Refinery performed well in the three months ended September 30, 2022, achieving crude utilization of 94 percent. Throughput increased in the third quarter of 2022 compared with 2021, as production slowed at the end of September 2021 as we prepared for a planned turnaround in the fourth quarter of 2021. Year-to-date, crude utilization was 88 percent. Throughput was impacted by outages on the pipeline that delivers feedstock to the refinery in the second quarter of 2022. In the first quarter of 2022, temporary unplanned equipment outages impacted throughput, and we operated at reduced rates early in the first quarter due to low market crack spreads.

At the Toledo Refinery, throughput decreased 24.4 thousand barrels per day and 19.8 thousand barrels per day during the three and nine months ended September 30, 2022, respectively, compared with 2021. A significant planned turnaround commenced during the second quarter, which was completed in early August. The refinery ramped up to full rates by mid-August. On September 20, 2022, there was an incident at the refinery and it remains shut down. In the first quarter of 2022, throughput was optimized in line with market demand, and was reduced as a result of temporary unplanned outages.

The Wood River and Borger refineries achieved crude utilization of 91 percent in the third quarter. Throughput increased 12.5 thousand barrels per day in the in third quarter of 2022 compared with 2021, due to temporary unplanned outages in the third quarter of 2021. The increase was partially offset by a planned fall turnaround at the Wood River Refinery beginning in September and completed in October. Year-to-date, throughput was relatively flat compared with 2021. We commenced planned spring turnarounds in March 2022 which impacted throughput and were completed in the second quarter. The spring 2022 turnaround at Wood River was delayed due to cold weather which resulted in labour shortages and cost overruns. At the Wood River Refinery, we operated at reduced rates early in the first quarter of 2022 to optimize margins as market conditions dictated.

Revenues and Gross Margin

Market crack spreads do not precisely mirror the configuration and product output of our refineries, however they are used as a general market indicator. 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. These factors include the type of crude oil feedstock 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.

Revenues increased $3.0 billion and $9.8 billion in the three and nine months ended September 30, 2022, respectively, compared with 2021. The increases were primarily due to significantly higher refined product pricing benchmarks, partially offset by lower sales volumes.

Gross margin increased $223 million and $1.8 billion in the three and nine months ended September 30, 2022, respectively, compared with 2021. The increases were largely due to significantly improved market crack spreads, partially offset by the impact of processing crude oil purchased in prior periods at higher prices, and lower sales volumes. In the three and nine months ended September 30, 2022, RINs costs were $320 million and $824 million, respectively (2021 – $248 million and $733 million, respectively). RINs prices averaged US$8.11 per barrel and US$7.45 per barrel in the three and nine months ended September 30, 2022, respectively (2021 – US$7.32 per barrel and US$6.97 per barrel, respectively).

In the three and nine months ended September 30, 2022, we incurred realized risk management gains of $77 million and losses of $120 million, respectively. We incurred a $36 million loss on the early liquidation of WTI positions in the second quarter. In the three and nine months ended September 30, 2022, we recorded unrealized gains of $8 million and $22 million, respectively, on our crude oil and refined products financial instruments.

Operating Expenses

Primary drivers of operating expenses for the three and nine months ended September 30, 2022, were repairs and maintenance, workforce, turnaround costs, and energy costs.

Operating expenses increased $195 million and $545 million in the three and nine months ended September 30, 2022, respectively, compared with 2021. The quarter-over-quarter increase was due to costs related to:

- The planned turnaround at the Toledo Refinery completed by early August.
- The fall turnaround at the Wood River Refinery.
- Increased maintenance at the Superior Refinery as we prepare for restart.
- Higher energy and utility pricing.
- Inflationary pressures on maintenance, electricity, workforce and chemical costs.

The year-over-year increase was mainly due to the same factors discussed above and the impact of planned turnarounds at the Wood River, Borger and Toledo refineries in the first half of 2022.

In the three and nine months ended September 30, 2022, per-unit operating expenses increased $4.87 per barrel of crude oil throughput and $5.08 per barrel of crude oil throughput, respectively. The increase was primarily due to the same factors as discussed above, combined with lower crude oil throughput.

DD&A

U.S. Manufacturing DD&A was $91 million and $259 million in the three and nine months ended September 30, 2022, respectively (2021 – $103 million and $320 million). Depreciation decreased in 2022 due to impairment charges recorded in the fourth quarter of 2021 at the Lima, Wood River and Borger refineries reducing the carrying value of our depreciable assets.

RETAIL

On September 13, 2022, we closed the sales of 337 gas stations within our retail fuels network for net cash proceeds of $404 million. We retained our commercial fuels business, which includes cardlock, bulk plant and travel centre locations. As of September 30, 2022, there were approximately 170 cardlock, bulk plant and travel center locations.

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2022**	2021	**2022**	2021
Revenues	**881**	592	**2,424**	1,540
Purchased Product	**846**	551	**2,317**	1,434
Gross Margin [1]	**35**	41	**107**	106
Expenses				
Operating	**38**	25	**96**	73
Operating Margin	**(3)**	16	**11**	33
Depreciation, Depletion and Amortization	**5**	11	**21**	36
Segment Income (Loss)	**(8)**	5	**(10)**	(3)

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

Select Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	**2022**	2021
Fuel Sales Volume, Including Wholesale				
Fuel Sales (millions of litres/d)	**6.9**	7.3	**6.7**	6.9
Fuel Sales per Retail Outlet (thousands of litres/d)	**15.2**	13.9	**13.5**	12.8

Revenues and Gross Margin

Revenues are largely dependent on retail pricing for motor fuels. Gross margin is primarily dependent on the differential between retail pricing and gasoline and diesel prices. In the three and nine months ended September 30, 2022, revenues increased $289 million and $884 million, respectively, mainly due to significantly higher benchmark gasoline and diesel prices. Gross margin was relatively flat in the three and nine months ended September 30, 2022, compared with 2021.

Operating Expenses

Primary drivers of our operating expenses for the three and nine months ended September 30, 2022, were repairs and maintenance, property tax, workforce and utilities.

DD&A

For the three and nine months ended September 30, 2022, Retail DD&A was $5 million and $21 million, respectively (2021 – $11 million and $36 million, respectively).

CORPORATE AND ELIMINATIONS

In the three and nine months ended September 30, 2022, our corporate risk management activities resulted in:

- Unrealized risk management gains of $16 million and $14 million, respectively, related to renewable power contracts and foreign exchange risk management contracts (2021 – gains of $2 million and $16 million, respectively).
- Realized risk management losses of $16 million and $23 million, respectively, relate to foreign exchange risk management contracts (2021 – gains of $1 million and losses of $91 million, respectively). The losses in 2021 were mainly due to the realization of WTI put and call option contracts acquired as part of the Arrangement.

Expenses

($ millions)	Three Months Ended September 30, 2022	2021	Nine Months Ended September 30, 2022	2021
General and Administrative	**128**	158	**545**	491
Finance Costs	**207**	360	**631**	836
Interest Income	**(21)**	(4)	**(44)**	(11)
Integration Costs	**27**	45	**79**	302
Foreign Exchange (Gain) Loss, Net	**316**	196	**406**	(93)
Revaluation (Gains)	**(549)**	—	**(549)**	—
Re-measurement of Contingent Payments	**(109)**	135	**142**	571
(Gain) Loss on Divestiture of Assets	**60**	(25)	**(244)**	(97)
Other (Income) Loss, Net	**(59)**	(107)	**(467)**	(208)
	—	758	**499**	1,791

General and Administrative

Primary drivers of our general and administrative expenses were employee long-term incentive costs, workforce costs and information technology costs. General and administrative expenses decreased quarter-over-quarter and increased year-over-year, primarily due to long-term incentive costs as a result of changes in our share price. Our closing common share price on September 30, 2022 was $21.22, a decrease from $24.49 on June 30, 2022, and an increase from $15.51 on December 31, 2021.

Finance Costs

In the three and nine months ended September 30, 2022, finance costs decreased by $153 million and $205 million, respectively, compared with 2021. The decrease is largely due to a $115 million net premium on the redemption of long-term debt in the third quarter of 2021. Comparatively, in the three and nine months ended September 30, 2022, we recorded a net discount on the redemption of long-term debt of $4 million and $29 million, respectively. In addition, our average long-term debt was lower in 2022 compared with 2021. Refer to the Liquidity and Capital Resources section of this MD&A for further details on long-term debt.

The weighted average interest rate of outstanding debt for the three and nine months ended September 30, 2022, was 4.8 percent and 4.7 percent, respectively (2021 – 4.7 percent and 4.6 percent, respectively).

Integration Costs

For the three and nine months ended September 30, 2022, we incurred $24 million and $76 million, respectively, of integration costs as a result of the Arrangement, not including capital expenditures (2021 – $45 million and $302 million, respectively). Integration costs decreased in 2022 as integration activities wind down.

In the first nine months of 2022, we incurred $81 million of Total Integration Costs[(1)], which include capital expenditures (2021 – $351 million). We expect to incur between $100 million to $150 million of Total Integration Costs this year.

Transaction costs of $3 million were recognized in net earnings (loss) in the three and nine months ended September 30, 2022 associated with the Sunrise Acquisition and the pending Toledo Acquisition.

Foreign Exchange

($ millions)	Three Months Ended September 30, 2022	2021	Nine Months Ended September 30, 2022	2021
Unrealized Foreign Exchange (Gain) Loss	**298**	111	**419**	(220)
Realized Foreign Exchange (Gain) Loss	**18**	85	**(13)**	127
	316	196	**406**	(93)

In the third quarter of 2022 and on a year-to-date basis, unrealized foreign exchange losses of $298 million and $419 million, respectively, were mainly as a result of the translation of our U.S. dollar denominated debt. Realized foreign exchange losses of $18 million and gains of $13 million were recorded in the three and nine months ended September 30, 2022, respectively, related to losses on the purchase of long-term debt, offset by gains on working capital.

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

Revaluation Gains

Cenovus recognized revaluation gains of $549 million in the third quarter of 2022 as part of the Sunrise Acquisition. As required by IFRS 3, when an acquirer achieves control in stages, the previously held interest is remeasured to fair value at the acquisition date with any gain or loss recognized in net earnings (loss). Refer to Note 4 of the interim Consolidated Financial Statements for further details.

Re-measurement of Contingent Payments

The contingent payment associated with the acquisition of a 50 percent interest in the FCCL Partnership from ConocoPhillips Company and certain of its subsidiaries ended on May 17, 2022, and the final payment was made in July 2022.

In connection with the Sunrise Acquisition, Cenovus agreed to make quarterly variable payments to BP Canada for up to eight quarters subsequent to August 31, 2022, if the average WCS crude oil price exceeds $52.00 per barrel. The quarterly payment will be calculated as $2.8 million plus the difference between the average WCS price less $53.00 multiplied by $2.8 million, for any of the eight quarters the average WCS price is equal to or greater than $52.00 per barrel. If the average WCS price is less than $52.00 per barrel, no payment will be made for that quarter. The maximum cumulative variable payment is $600 million. For accounting purposes, the variable payment will be re-measured at fair value at each reporting date until the earlier of the cumulative maximum $600 million is reached or the eight quarters have lapsed, with changes in fair value recognized in net earnings (loss). The variable payment was recorded at a fair value of $600 million on the date of acquisition using an option pricing model, and will subsequently be re-measured at fair value with changes in fair value recognized in net earnings (loss) at each reporting date.

As at September 30, 2022, the fair value of the variable payment was estimated to be $491 million resulting in a non-cash re-measurement gain of $109 million. As at September 30, 2022, there is no outstanding payable under this agreement.

As of September 30, 2022, average WCS forward pricing for the remaining term of the variable payment is approximately $72.38 per barrel.

(Gain) Loss on Divestiture of Assets

In the third quarter of 2022, we recognized a loss on divestiture of assets of $60 million (2021 – $25 million gain), primarily due to the closing of the retail divestiture. In the first nine months of 2022, we recognized a gain on divestiture of assets of $244 million (2021 – $97 million), due to the closing of the sales of our Tucker and Wembley assets in the first quarter of 2022, and the divestiture of 12.5 percent of our interest in the White Rose field and satellite extensions in the second quarter of 2022 as well as the retail divestiture.

Other (Income) Loss, Net

For the three months ended September 30, 2022, other income decreased by $48 million primarily due to the settlement of a legal claim in favour of Cenovus in the third quarter of 2021. In the first nine months of 2022, other income increased by $259 million compared with 2021, primarily due to:

- Rebuild insurance proceeds of $271 million related to the Superior Refinery in the first nine months of 2022, compared with business interruption proceeds of $45 million in 2021.
- Insurance proceeds in the first nine months of 2022, related to a 2018 incident in the Atlantic region.

DD&A

DD&A for the three and nine months ended September 30, 2022, was $27 million and $86 million, respectively (2021 – $29 million and $91 million, respectively).

Income Tax

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2022**	2021	**2022**	2021
Current Tax				
Canada	**187**	58	**1,124**	72
United States	**(185)**	—	**96**	—
Asia Pacific	**64**	34	**173**	115
Other International	**10**	—	**10**	1
Current Tax Expense (Recovery)	**76**	92	**1,403**	188
Deferred Tax Expense (Recovery)	**568**	191	**625**	281
Total Tax Expense (Recovery)	**644**	283	**2,028**	469

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 months ended September 30, 2022, the Company recorded a current tax expense related to taxable income arising in Canada and Asia Pacific. The increase is due to higher earnings compared to 2021 and the availability of tax deductions to calculate taxable income. For the three months ended September 30, 2022, the Company recorded a current tax recovery related to lower U.S. taxable income.

For the nine months ended September 30, 2022, the Company recorded a current tax expense related to taxable income arising in Canada, the U.S. and Asia Pacific. The increase is due to higher earnings compared to 2021 and the availability of tax deductions to calculate taxable income.

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 for many reasons, including, but not limited to, different tax rates between jurisdictions, non-taxable foreign exchange (gains) losses, adjustments for changes in tax rates and other tax legislation.

LIQUIDITY AND CAPITAL RESOURCES

During the first half of 2022, we further defined our capital allocation framework to ensure we continue to strengthen our balance sheet, enable flexibility in both high and low commodity price environments, and improve our shareholder value proposition. The Company's capital allocation framework enables a shift to paying out a higher percentage of Excess Free Funds Flow to shareholders with lower leverage and a lower risk profile. Our long-term Net Debt to Adjusted Funds Flow Target is approximately 1.0 times at the bottom of the cycle.

We expect to fund our near-term cash requirements through cash from operating activities and prudent use of our balance sheet capacity. This includes draws on our committed credit facilities, uncommitted demand facilities and other corporate and financial opportunities. 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 are dependent on current credit ratings and market conditions.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
($ millions)	**2022**	2021	**2022**	2021
Cash From (Used In)				
Operating Activities	**4,089**	2,138	**8,433**	3,735
Investing Activities	**(690)**	(327)	**(1,144)**	(547)
Net Cash Provided (Used) Before Financing Activities	**3,399**	1,811	**7,289**	3,188
Financing Activities	**(3,822)**	(913)	**(6,926)**	(1,591)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**224**	57	**258**	35
Increase (Decrease) in Cash and Cash Equivalents	**(199)**	955	**621**	1,632

As at ($ millions)	**September 30, 2022**	December 31, 2021
Cash and Cash Equivalents	**3,494**	2,873
Total Debt	**8,774**	12,464

Cash From (Used in) Operating Activities

For the three months ended September 30, 2022, cash generated from operating activities increased compared with 2021 due to changes in non-cash working capital and higher Operating Margin. In the first nine months of 2022, cash generated from operating activities increased compared with 2021 due to a higher Operating Margin, combined with changes in non-cash working capital and lower integration costs.

Excluding the contingent payment, our adjusted working capital was $4.6 billion at September 30, 2022. At December 31, 2021, adjusted working capital excluding the contingent payment and assets held for sale and liabilities related to assets held for sale was $3.8 billion. The increase was primarily due to the improved commodity price environment as discussed in the Operating and Financial Results section of this MD&A. Working capital increased due to higher cash, accounts receivable and inventories, partially offset by higher income tax payable.

Our adjusted working capital decreased $1.5 billion compared with June 30, 2022, as we realized accounts receivable and inventory balances from June 30, 2022, when commodity prices were higher.

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 third quarter of 2022 compared with 2021 largely due to the Sunrise Acquisition in 2022 and higher capital spending. The increase was partially offset by the divestiture of 337 gas stations within our retail fuels network in 2022.

Cash used in investing activities was higher in the first nine months of 2022 compared with 2021 mainly due to higher capital spending and the Sunrise Acquisition in 2022. The increase was partially offset by cash acquired in the Arrangement in 2021, higher proceeds from divestitures in 2022 and changes in non-cash working capital.

Cash From (Used in) Financing Activities

In the third quarter, we purchased unsecured notes due between 2025 and 2043 with principal amounts of US$2.2 billion at a premium of US$23 million.

As part of our overall deleveraging, in the first nine months of 2022, we:

- Paid US$402 million to purchase the full amount of our 3.80 percent unsecured notes due in 2023 and 4.00 percent unsecured notes due in 2024, with principal amounts of US$384 million. We paid a premium on redemption of US$18 million.
- Paid $750 million to purchase the full amount of our 3.55 percent unsecured notes due in 2025, with principal amounts of $750 million.
- Paid US$2.2 billion to purchase unsecured notes due between 2025 and 2043, as discussed above.
- Repaid $81 million in short-term borrowings.

In the nine months ended September 30, 2022, the Company purchased 97 million common shares through our NCIB, at a volume weighted average price of $22.10 per common share for a total of $2.1 billion. The common shares were subsequently cancelled.

Adjusted Funds Flow, Free Funds Flow and Excess Free Funds Flow

Adjusted Funds Flow is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations. Free Funds Flow is a non-GAAP financial measure used to assist in measuring the available funds the Company has after financing its capital programs. Excess Free Funds Flow is a non-GAAP financial measure used by the Company to deliver shareholder returns and allocate capital according to our shareholder returns plan. Excess Free Funds Flow is a new metric as of June 30, 2022.

($ millions)	Three Months Ended September 30, 2022	2021	Nine Months Ended September 30, 2022	2021
Cash From (Used in) Operating Activities	**4,089**	2,138	**8,433**	3,735
(Add) Deduct:				
Settlement of Decommissioning Liabilities	**(55)**	(38)	**(101)**	(67)
Net Change in Non-Cash Working Capital	**1,193**	(166)	**(98)**	(1,498)
Adjusted Funds Flow	**2,951**	2,342	**8,632**	5,300
Capital Investment	**866**	647	**2,434**	1,728
Free Funds Flow	**2,085**	1,695	**6,198**	3,572
Add (Deduct):				
Base Dividends Paid on Common Shares	**(205)**	(35)		
Dividends Paid on Preferred Shares	**(9)**	(9)		
Settlement of Decommissioning Liabilities	**(55)**	(38)		
Principal Repayment of Leases	**(78)**	(70)		
Acquisitions, Net of Cash Acquired	**(389)**	—		
Proceeds From Divestitures, Net of Cash Paid	**407**	83		
Excess Free Funds Flow	**1,756**	1,626		

Returns to Shareholders Target

($ millions)	Three Months Ended September 30, 2022	June 30, 2022
Excess Free Funds Flow	**1,756**	2,020
Target Return [(1)]	**878**	1,010
Less: Purchase of Common Shares Under NCIB	**(659)**	(1,018)
Returns to Shareholders Under/(Over) Target Before Variable Dividend	**219**	(8)

(1) Based on our capital allocation framework, as a result of Net Debt as at June 30, 2022 and March 31, 2022, respectively, being less than $9 billion and greater than $4 billion, Target Return was determined to be 50 percent of Excess Free Funds Flow.

Long-Term Debt and Total Debt

Long-term debt, including current portion, and Total Debt, as at September 30, 2022, was $8.8 billion (December 31, 2021 – $12.4 billion and $12.5 billion, respectively). The decrease in long-term debt and Total Debt was due to the purchase of US$2.6 billion and $750 million of our unsecured notes in 2022.

As at September 30, 2022, we were in compliance with all of the terms of our debt agreements.

Available Sources of Liquidity

The following sources of liquidity are available as at September 30, 2022:

($ millions)	Maturity	Amount Available
Cash and Cash Equivalents	**N/A**	**3,494**
Committed Credit Facility [(1)]		
Revolving Credit Facility – Tranche A	**August 18, 2025**	**4,000**
Revolving Credit Facility – Tranche B	**August 18, 2024**	**2,000**
Uncommitted Demand Facilities		
Cenovus Energy Inc. [(2)]	**N/A**	**1,022**
WRB Refining LP [(3)]	**N/A**	**308**
Sunrise Oil Sands Partnership [(4)]	**N/A**	**10**

(1) No amounts were drawn on the committed credit facility as at September 30, 2022.
(2) Our uncommitted demand facilities includes $1.9 billion, of which $1.4 billion may be drawn for general purposes, or the full amount can be available to issue letters of credit. As of September 30, 2022, there were outstanding letters of credit aggregating to $472 million (December 31, 2021 – $565 million) and no direct borrowings.
(3) Represents Cenovus's 50 percent share of US$450 million (our proportionate share – US$225 million) available to cover short-term working capital requirements. As at September 30, 2022, no amounts were drawn on these facilities.
(4) Available for general purposes. There were no amounts drawn on this demand facility as at September 30, 2022.

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.

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

In September 2022, we paid US$2.2 billion to purchase a portion of our unsecured notes. The following principal amounts of our unsecured notes were purchased:

- 5.38 percent due 2025 – US$533 million.
- 4.25 percent due 2027 – US$589 million.
- 4.40 percent due 2029 – US$510 million.
- 6.75 percent due 2039 – US$455 million.
- 4.45 percent due 2042 – US$58 million.
- 5.20 percent due 2043 – US$29 million.

In the first quarter of 2022, we paid US$402 million to purchase the full amount of our 3.80 percent unsecured notes due in 2023 and 4.00 percent unsecured notes due in 2024, with principal amounts of US$384 million. In the second quarter of 2022, we paid $750 million to purchase the full amount of our 3.55 percent unsecured notes due in 2025.

A premium on redemption of US$41million was recorded in finance costs on the above transactions.

At September 30, 2022, the total outstanding principal amount of U.S. dollar denominated unsecured notes was US$4.8 billion and the total outstanding principal amount of Canadian dollar denominated unsecured notes was $2.0 billion.

	Unsecured Notes	
	U.S. Dollar Denominated (US $ millions)	**Canadian Dollar Denominated** ($ millions)
As at December 31, 2021	7,385	2,750
Purchases	(2,558)	(750)
As at September 30, 2022	**4,827**	**2,000**

Base Shelf Prospectus

We have a base shelf prospectus that allows us to offer, from time to time, up to US$5.0 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere, where permitted by law. The base shelf prospectus will expire in November 2023. As at September 30, 2022, US$4.7 billion remained available under the base shelf prospectus for permitted offerings (December 31, 2021 – US$4.7 billion). Offerings under the base shelf prospectus are subject to market availability.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, specified financial measures consisting of a Net Debt to Capitalization Ratio, Net Debt to Adjusted Funds Flow Ratio and Net Debt to Adjusted EBITDA Ratio. Net Debt to Adjusted Funds Flow is a new metric as at March 31, 2022. Refer to Note 19 of the interim Consolidated Financial Statements for further details.

We define Net Debt as short-term borrowings and the current and long-term portions of long-term debt, net of cash and cash equivalents and short-term investments. The components of the ratios include Capitalization, Adjusted Funds Flow and Adjusted EBITDA. We define Capitalization as Net Debt plus Equity. We define Adjusted Funds Flow, as used in the Net Debt to Adjusted Funds Flow Ratio, as cash from (used in) operating activities, less settlement of decommissioning liabilities and net change in operating non-cash working capital calculated on a trailing twelve-month basis. We define Adjusted EBITDA as net earnings before finance costs, net of capitalized interest, interest income, income tax expense (recovery), DD&A, E&E write-down, goodwill impairments, unrealized (gain) loss on risk management, foreign exchange (gain) loss, revaluation (gains), re-measurement of contingent payment, (gain) loss on divestiture of assets, other (income) loss, net and share of (income) loss from equity-accounted affiliates calculated on a trailing twelve-month basis. These ratios are used to steward our overall debt position and as measures of our overall financial strength.

As at	**September 30, 2022**	December 31, 2021
Net Debt to Capitalization Ratio (percent)	**16**	29
Net Debt to Adjusted Funds Flow Ratio (times)	**0.5**	1.3
Net Debt to Adjusted EBITDA Ratio (times)	**0.4**	1.2

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

As at September 30, 2022, our Net Debt to Capitalization Ratio decreased compared with December 31, 2021, primarily due to higher net earnings and ongoing reductions in Net Debt during the trailing twelve-month period.

Our Net Debt to Adjusted Funds Flow Ratio and Net Debt to Adjusted EBITDA Ratio decreased compared with December 31, 2021, as a result of higher Operating Margin and lower Net Debt in the trailing twelve-months. See the Operating and Financial Results section of this MD&A for more information on Operating Margin and Net Debt.

Share Capital and Stock-Based Compensation Plans

As at September 30, 2022, there were approximately 1,923 million common shares outstanding (December 31, 2021 – 2,001 million common shares) and 36 million preferred shares outstanding (December 31, 2021 – 36 million preferred shares). Refer to Note 24 of the interim Consolidated Financial Statements for further details.

In November 2021, we commenced a NCIB for the purchase of up to 146.5 million of the Company's common shares until November 8, 2022. In the first nine months of 2022, Cenovus purchased and settled 97 million common shares for $2.1 billion (year ended December 31, 2021 – 17 million common shares for $265 million), at a volume weighted average price of $22.10 per common share. The common shares were subsequently cancelled. From October 1, 2022 to November 1, 2022, Cenovus purchased an additional 4 million common shares for $94 million. Cenovus purchased 118 million common shares for $2.5 billion from the commencement of our NCIB to November 1, 2022. Our existing NCIB expires on November 8, 2022. On November 1, 2022, the Board approved filing an application with the TSX to renew our NCIB to purchase up to 10 percent of the Company's public float, or approximately 137 million of the Company's common shares for twelve months once approved by the TSX.

As at September 30, 2022, there were approximately 57 million Cenovus Warrants outstanding (December 31, 2021 – 65 million Cenovus Warrants). Each Cenovus Warrant entitles the holder to acquire one common share for a period of five years (from the date of issue) at an exercise price of $6.54 per common share. The Cenovus Warrants expire on January 1, 2026. Refer to Note 24 of the interim Consolidated Financial Statements for further details.

Refer to Note 26 of the interim Consolidated Financial Statements for further details on our stock option plans and our performance share unit, restricted share unit and deferred share unit plans.

Our outstanding share data is as follows:

As at October 28, 2022	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**1,918,887**	**N/A**
Cenovus Warrants	**57,355**	**N/A**
Series 1 Preferred Shares	**10,740**	**N/A**
Series 2 Preferred Shares	**1,260**	**N/A**
Series 3 Preferred Shares	**10,000**	**N/A**
Series 5 Preferred Shares	**8,000**	**N/A**
Series 7 Preferred Shares	**6,000**	**N/A**
Stock Options	**18,263**	**9,190**
Other Stock-Based Compensation Plans	**16,928**	**1,608**

Common Share Dividends

In the third quarter of 2022, we paid base dividends of $205 million or $0.105 per common share (2021 – $35 million or $0.018 per common share). In the first nine months of 2022, we paid base dividends of $481 million or $0.2450 per common share (2021 – $106 million or $0.0525 per common share).

The Board declared a fourth quarter base dividend of $0.105 per common share, payable on December 30, 2022, to common shareholders of record as at December 15, 2022.

The Board declared a fourth quarter variable dividend of $0.114 per common share, payable on December 2, 2022, to common shareholders of record as at November 18, 2022.

The declaration of common share dividends is at the sole discretion of Cenovus's Board and is considered quarterly.

Cumulative Redeemable Preferred Share Dividends

In the three and nine months ended September 30, 2022, 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 Cenovus's Board and is considered quarterly. The Board declared a fourth quarter dividend on the series 1, 2, 3, 5 and 7 preferred shares of $9 million, payable on January 3, 2023, to preferred shareholders of record as of December 15, 2022.

Capital Investment Decisions

Our 2022 capital program is forecast to be between $3.3 billion and $3.7 billion. Our Future Capital Investment is focused on maintaining safe and reliable operations, while positioning the Company to drive enhanced shareholder value. We expect our annual upstream production to average between 780 thousand BOE per day and 810 thousand BOE per day. Given the incident at the Toledo Refinery, we now expect our downstream crude oil throughput to fall modestly outside the guidance range of 530 thousand barrels per day to 580 thousand barrels per day in 2022.

Contractual Obligations and Commitments

We have obligations for goods and services entered into in the normal course of business. Commitments are largely related to transportation agreements and obligations that have original maturities of less than one year are excluded. For further information, see Note 31 to the interim Consolidated Financial Statements.

Our total commitments were $34.5 billion as at September 30, 2022, of which $21.3 billion are for various transportation and storage commitments and $10.6 billion are for fuel purchase commitments. Transportation commitments include $9.1 billion that are subject to regulatory approval or have been approved, but are not yet in service. Terms are up to 20 years subsequent to the date of commencement and should help align with the Company's future transportation requirements.

Our commitments with HMLP at September 30, 2022, include $2.2 billion related to transportation, storage and other long-term contracts.

As at September 30, 2022, outstanding letters of credit issued as security for performance under certain contracts totaled $472 million (December 31, 2021 – $565 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 interim Consolidated Financial Statements.

Transactions with Related Parties

Transactions with HMLP are related party transactions as we have a 35 percent ownership interest in HMLP. As the operator of the assets held by HMLP, we provide management services for which we recover shared service costs. We are also the contractor for HMLP and construct its assets on a cost recovery basis with certain restrictions. For the three and nine months ended September 30, 2022, we charged HMLP $56 million and $133 million, respectively, for construction and management services (2021 – $101 million and $165 million, respectively).

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, 2022, we incurred costs of $64 million and $197 million, respectively, for the use of HMLP's pipeline systems, as well as transportation and storage services (2021 – $70 million and $215 million, respectively).

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 2021 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, our business, reputation, financial condition, results of operations and cash flows, which may reduce or restrict our ability to pursue our strategic priorities, meet our targets or outlooks, goals, initiatives and ambitions, respond to changes in our operating environment, pay dividends to our shareholders, continue with share purchases under our NCIB 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

Dividend Payments and Purchase of Securities

The payment of dividends, whether base or variable, the continuation of our dividend reinvestment plan and any potential purchase by Cenovus of our securities is at the discretion of our Board, and is dependent upon, among other things, financial performance, debt covenants, satisfying solvency tests, our ability to meet financial obligations as they come due, working capital requirements, future tax obligations, future capital requirements, commodity prices and other business and risk factors set forth in this MD&A and in our 2021 annual MD&A.

Specifically, in connection with Cenovus's updated capital allocation framework, the Company will target returns to shareholders as a percentage of Excess Free Funds Flow, through share buybacks or variable dividends, based on Net Debt at the preceding quarter-end, as described in the Overview of Cenovus section of this MD&A. The frequency and amount of variable dividend payments, if any, may vary significantly over time as a result of our Net Debt, Excess Free Funds Flow, amount of share buybacks and other factors inherent with our capital allocation framework from time to time. As the payment of dividends remains at the discretion of our Board and dependent on, among other things, the factors described above, the Company can provide no assurance that it will continue to pay base or variable dividends or authorize share buybacks at the current rate or at all.

Further, the individual or aggregate amount of base or variable dividends, if any, paid by Cenovus from time to time may result in adjustments to the exercise price and the exchange basis (the number of common shares received for each Cenovus Warrant exercised) of the Cenovus Warrants under the terms of the indenture governing the Cenovus Warrants. Such adjustments may impact the value received by Cenovus upon the exercise of Cenovus Warrants and may result in additional issuances of common shares on the exercise of Cenovus Warrants which may have a further dilutive effect on the ownership interest of shareholders of Cenovus and on Cenovus's earnings per share.

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, our level of shareholder returns 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, renewable power contracts and generally through our access to committed credit facilities. In certain instances, we use financial instruments to manage our exposure to price volatility on a portion of our refined products, crude oil and natural gas production, and related inventory or volumes in long-distance transit. Previously, we had also used derivative instruments to manage our overall exposure to volatility in cash flow using WTI derivative instruments, however, as announced on April 4, 2022, we suspended our crude oil sales price risk management activities related to WTI. All WTI positions impacted by this decision were closed by June 30, 2022.

Risks Associated with Derivative Financial Instruments

Derivative 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.

Derivative 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. These risks are managed through hedging limits authorized according to our Market Risk Management Policy.

Although we have suspended our crude oil sales price risk management activities related to WTI, certain financial instruments related to our condensate, feedstock and refined product price risk management programs which include WTI, remain outstanding and will continue to be used, in addition to electricity, interest and exchange rates applicable to our business. As such, we will be exposed to the risk of a loss from adverse changes in the market value of any such financial instruments. These financial instruments may also limit the benefit to us if commodity prices, interest or foreign exchange rates change. Fluctuations in the price of WTI may have a larger impact on our financial condition, results of operations, cash flows, growth, access to capital, our level of shareholder returns and our cost of borrowing, compared to the periods prior to the suspension of our crude oil sales price risk management activities related to WTI. 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 28 and 29 to the interim Consolidated Financial Statements.

Impact of Financial Risk Management Activities

Cenovus makes storage and transportation decisions, considering 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 and improve cash flow stability.

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. In the three and nine months ended September 30, 2022, we incurred a realized gain and realized loss, respectively, on our risk management positions due to the settlement of benchmark prices relative to our risk management contract prices, but recognized a loss and gain, respectively, on the underlying physical inventory sold during such period due to changing benchmark prices.

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.

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 annual Consolidated Financial Statements for the year ended December 31, 2021.

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, 2021. There have been no changes to our critical judgments used in applying accounting policies and key sources of measurement uncertainty during the nine months ended September 30, 2022.

New Accounting Standards and Interpretations not yet Adopted

A number of new accounting standards, amendments to accounting standards and interpretations were effective for annual periods beginning on or after January 1, 2022, but are not material to Cenovus's operations. There were no new or amended accounting standards or interpretations issued during the nine months ended September 30, 2022, that are expected to have a material impact on the Company's 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, 2022. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of ICFR. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at September 30, 2022.

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.

ADVISORY

Oil and Gas Information

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

Forward-looking Information

This document contains forward-looking statements and other information (collectively "forward-looking information") about the Company's current expectations, estimates and projections, made in light of the Company's experience and perception of historical trends. Although the Company believes that the expectations represented by such forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct.

This forward-looking information is identified by words such as “anticipate”, “believe”, “capacity”, “commit”, “continue”, “could”, “estimate”, “expect”, “focus”, “forecast”, “future”, “may”, “objective”, “opportunities”, “option”, “plan”, “potential”, “project”, “seek”, “target”, and “will”, or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: delivering value over the long-term; maximizing, growing or enhancing shareholder value and/or returns; returning incremental capital to shareholder beyond the base dividend; allocating and paying out Excess Free Funds Flow under the capital allocation framework; deleveraging the balance sheet; opportunistic share repurchases and variable dividend distributions; applying for approval to conduct a new NCIB; safety performance and culture; ESG governance and leadership; the Company’s targets for each of its five ESG focus areas; Free Funds Flow generation, allocation, pay out and growth through pricing cycles; daily annual upstream production and downstream throughput; monitoring overall market dynamics to assess management of upstream production; monitoring downstream market fundamentals and optimizing refinery run rates; funding near-term cash requirements and meeting payment obligations; maintaining investment grade credit ratings; Debt reduction and Debt and Net Debt targets; disciplined capital allocation; ensuring sufficient liquidity through all stages of the economic cycle strengthening and maintaining a strong balance sheet; flexibility in both high and low commodity price environments; managing capital structure; Net Debt to Adjusted Funds Flow Ratio and Net Debt to Adjusted EBITDA Ratio; cost savings and reductions; cost structure; interest expense; financial results; margin enhancement; improving efficiencies to drive incremental capital, operating and general and administrative cost reductions; shortening and optimizing the value chain; reducing condensate costs associated with heavy oil transportation; maintaining the Company’s capital program and sustaining the base dividend at US$45 WTI per barrel; maximizing value received for products; mitigating the impact of volatility in light-heavy crude oil differentials; partially mitigating the impact of exposure to various prices for commodities and associated price differentials and refining margins; managing upstream production rates in response to pipeline capacity constraints, voluntary and mandated production curtailments and crude oil differentials; variable payments in respect of the Sunrise acquisition; continued use of financial instruments to mitigate exposure to various commodities (including WTI, utilized in condensate and price risk management for refining operations) and products, including associated price differentials and refining margins; drilling activity, asset integrity and emissions initiatives in the conventional segment; initial production and exploration of new fields or projects; financial resilience; adjusting capital and operating spending, drawing down on credit facilities or repaying existing debt, adjusting dividends paid to shareholders, purchasing Cenovus common shares for cancellation, issuing new debt, or issuing new shares; future capital investment for: maintaining safe and reliable operations, sustaining Oil Sands production, sustaining drilling programs in the conventional segment, the Superior Refinery rebuild project, the Terra Nova ALE project and White Rose project, refining operations and reliability and debottlenecking at the Lloydminster Refinery to increase throughput capacity; the status and timing of closing the Toledo Acquisition and any opportunities and benefits (including increases in throughput) therefrom; applying the Company’s operating model at Sunrise and exceeding nameplate capacity at that facility; capital expenditure required to achieve first oil for the West White Rose project; capturing value from crude oil and natural gas production through to the sale of finished products such as transportation fuels; reinvestment in the business and diversification; the winter drilling program in the Conventional business; resuming projects, including restarting the West White Rose project and achieving first and peak oil therefrom; the return to the field of the floating, production, storage and offloading unit for the Terra Nova ALE project; first gas production from the MDA field; drilling development wells and construction of production facilities and production therefrom; liabilities from legal proceedings; and the Company’s outlook for commodities and the Canadian dollar and the effects thereof on Cenovus.

Readers are cautioned not to place undue reliance on forward-looking information as the Company’s actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to the Company and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include, but are not limited to: forecast oil and natural gas, natural gas liquids, condensate and refined products prices, light-heavy crude oil price differentials; the Company’s ability to realize the anticipated benefits and anticipated cost synergies of the Arrangement and other acquisitions; the Company’s ability to successfully integrate the legacy Husky business with its own and any costs associated therewith; the accuracy of any assessments undertaken in connection with the Arrangement or other acquisitions; forecast production and throughput volumes; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; the absence of significant adverse changes to government policies, legislation and regulations (including related to climate change), Indigenous relations, interest rates, inflation, foreign exchange rates, competitive conditions and the supply and demand for crude oil and natural gas, NGLs, condensate and refined products; the political, economic and social stability of jurisdictions in which the Company operates; the absence of significant disruption of operations, including as a result of harsh weather, natural disaster, accident, civil unrest or other similar events; the prevailing climatic conditions in the Company’s operating locations; achievement of further cost reductions and sustainability thereof; applicable royalty regimes, including expected royalty rates; future improvements in availability of product transportation capacity; increase to the Company’s share price and market capitalization over the long term; opportunities to purchase shares for cancellation at prices acceptable to the Company; the sufficiency of cash balances, internally generated cash flows, existing credit facilities, management of the Company’s asset portfolio and access to capital and insurance coverage to pursue and fund future investments, sustainability and development plans and dividends, including any increase thereto; production from the Company's Conventional segment providing an economic hedge for the natural gas required as a fuel source at both the Company's oil sands and refining operations; realization of expected capacity to store within the Company's oil sands reservoirs barrels not yet produced, including that the Company will be able to time production and sales of our inventory at later dates when demand has increased, pipeline and/or storage capacity has improved and future crude oil differentials have narrowed; the WTI-WCS differential in Alberta remains largely tied to global supply factors and heavy crude processing capacity; the ability of the Company's refining capacity, dynamic storage, existing pipeline commitments, crude-by-rail loading capacity and financial hedge transactions to partially mitigate a portion of the Company's WCS crude oil volumes against wider differentials; the Company's ability to produce from oil sands facilities on an unconstrained basis; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; the accuracy of accounting estimates and judgments; the Company's ability to obtain necessary regulatory and partner approvals; the successful, timely and cost effective implementation of capital projects, development projects or stages thereof; the Company's ability to generate sufficient cash flow to meet current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; the Company's ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; the Company's ability to complete acquisitions and dispositions, including with desired transaction metrics and within expected timelines; the accuracy of climate scenarios and assumptions, including third party data on which the Company relies; ability to access and implement all technology and equipment necessary to achieve expected future results, including in respect of climate and GHG emissions targets and ambitions and the commercial viability and scalability of emission reduction strategies and related technology and products; continuing; collaboration with the government, Pathways Alliance and other industry organizations; alignment of realized WCS and WCS prices used to calculate the variable payment to BP; market and business conditions; forecast inflation and other assumptions inherent in the Company's 2022 guidance available on cenovus.com and as set out below; the availability of Indigenous owned or operated businesses and the Company's ability to retain them; and other risks and uncertainties described from time to time in the filings the Company makes with securities regulatory authorities.

2022 guidance, as updated July 27, 2022, and available on cenovus.com, assumes: Brent prices of US$103.00 per barrel, WTI prices of US$100.00 per barrel; WCS of US$84.00 per barrel; Differential WTI-WCS of US$16.00 per barrel; AECO natural gas prices of $5.30 per thousand cubic feet; Chicago 3-2-1 crack spread of US$38.00 per barrel; and an exchange rate of $0.78 US$\C$.

The risk factors and uncertainties that could cause the Company's actual results to differ materially from the forward-looking information, include, but are not limited to: the effect of the COVID-19 pandemic, including any variants thereof, on the Company's business, including any related restrictions, containment, and treatment measures taken by varying levels of government in the jurisdictions in which the Company operates; the success of the Company's COVID-19 workplace policies and the return of people to the Company's workplace; the Company's ability to realize the anticipated benefits of the Arrangement and other acquisitions in a timely manner or at all; the Company's ability to successfully integrate the legacy Husky business and other acquired businesses with its own in a timely and cost effective manner; unforeseen or underestimated liabilities associated with the Arrangement or other acquisitions; risks associated with acquisitions and dispositions; the Company's ability to access or implement some or all of the technology necessary to efficiently and effectively operate its assets and achieve expected future results including in respect of climate and GHG emissions targets and ambitions and the commercial viability and scalability of emission reduction strategies and related technology and products; the development and execution of implementing strategies to meet climate and GHG emissions targets and ambitions; the effect of new significant shareholders; volatility of and other assumptions regarding commodity prices; the duration of any market downturn; foreign exchange risk, including related to agreements denominated in foreign currencies; the Company's continued liquidity is sufficient to sustain operations through a prolonged market downturn; WTI-WCS differential will remain largely

tied to global supply factors and heavy crude processing capacity; the Company's ability to achieve lower transportation costs as a result of temporarily suspending the crude-by-rail program; the Company's ability to realize the expected impacts of its capacity to store within its oil sands reservoirs barrels not yet produced, including possible inability to time production and sales at later dates when pipeline and/or storage capacity and crude oil differentials have improved; the effectiveness of the Company's risk management program; the accuracy of cost estimates regarding commodity prices, currency and interest rates; lack of alignment of realized WCS prices and WCS prices used to recalculate the variable payment to BP; product supply and demand; the accuracy of the Company's share price and market capitalization assumptions; market competition, including from alternative energy sources; risks inherent in the Company's marketing operations, including credit risks, exposure to counterparties and partners, including the ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in the operation of the Company's crude-by-rail terminal, including health, safety and environmental risks; the Company's ability to maintain desirable ratios of Net Debt to Adjusted EBITDA and Net Debt to Adjusted Funds Flow; the Company's ability to access various sources of debt and equity capital, generally, and on acceptable terms; the Company's ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to the Company or any of its securities; changes to the Company's dividend plans; the Company's ability to utilize tax losses in the future; the accuracy of the Company's reserves, future production and future net revenue estimates; the accuracy of the Company's accounting estimates and judgements; the Company's ability to replace and expand crude oil and natural gas reserves; the costs to acquire exploration rights, undertake geological studies, appraisal drilling and project developments; potential requirements under applicable accounting standards for impairment or reversal of estimated recoverable amounts of some or all of the Company's assets or goodwill from time to time; the Company's ability to maintain its relationships with its partners and to successfully manage and operate its integrated operations and business; reliability of the Company's assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events resulting in operational interruptions, including blowouts, fires, explosions, railcar incidents or derailments, aviation incidents, gaseous leaks, migration of harmful substances, loss of containment, releases or spills, including releases or spills from offshore facilities and shipping vessels at terminals or hubs and as a result of pipeline or other leaks, corrosion, epidemics or pandemics, and catastrophic events, including, but not limited to, war, extreme weather events, natural disasters, iceberg incidents, acts of vandalism and terrorism, and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites and other accidents or similar events; refining and marketing margins; cost escalations, including inflationary pressures on operating costs, such as labour, materials, natural gas and other energy sources used in oil sands processes and downstream operations and increased insurance deductibles or premiums; the cost and availability of equipment necessary to the Company's operations; potential failure of products to achieve or maintain acceptance in the market; risks associated with the energy industry's and the Company's reputation, social license to operate and litigation related thereto; unexpected cost increases or technical difficulties in operating, constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining bitumen and/or crude oil into petroleum and chemical products; risks associated with technology and equipment and its application to the Company's business, including potential cyberattacks; geo-political and other risks associated with the Company's international operations; risks associated with climate change and the Company's assumptions relating thereto; the timing and the costs of well and pipeline construction; the Company's ability to access markets and to secure adequate and cost effective product transportation including sufficient pipeline, crude-by-rail, marine or alternate transportation, including to address any gaps caused by constraints in the pipeline system or storage capacity; availability of, and the Company's ability to attract and retain, critical talent; possible failure to obtain and retain qualified leadership and personnel, and equipment in a timely and cost efficient manner; changes in labour demographics and relationships, including with any unionized workforces; unexpected abandonment and reclamation costs; changes in the regulatory frameworks, permits and approvals in any of the locations in which the Company operates or to any of the infrastructure upon which it relies; government actions or regulatory initiatives to curtail energy operations or pursue broader climate change agendas; changes to regulatory approval processes and land use designations, royalty, tax, environmental, GHG, carbon, climate change and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on the Company's business, its financial results and Consolidated Financial Statements; changes in general economic, market and business conditions; the impact of production agreements among OPEC and non-OPEC members; the political, social and economic conditions in the jurisdictions in which the Company operates or supplies; the status of the Company's relationships with the communities in which it operates, including with Indigenous 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 the Company. In addition, there are risks that the effect of actions taken by us in implementing targets, commitments and ambitions for ESG focus areas may have a negative impact on our existing business, growth plans and future results from operations.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward-looking information. For a full discussion of the Company's material risk factors, see Risk Management and Risk Factors in the Company's Annual MD&A, and in this MD&A, and the risk factors described in other documents the Company files from time to time with securities regulatory authorities in Canada, available on SEDAR at sedar.com, and with the U.S. Securities and Exchange Commission on EDGAR at sec.gov, and on the Company's website at cenovus.com.

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

ABBREVIATIONS

The following abbreviations have been used in this document:

Crude Oil		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
Mbbls/d	thousand barrels per day	MMcf	million cubic feet
MMbbls	million barrels	MMcf/d	million cubic feet per day
BOE	barrel of oil equivalent	Bcf	billion cubic feet
MBOE	thousand barrels of oil equivalent	MMBtu	million British thermal units
MBOE/d	thousand barrels of oil equivalent per day	GJ	gigajoule
MMBOE	million barrels of oil equivalent	AECO	Alberta Energy Company
WTI	West Texas Intermediate	NYMEX	New York Mercantile Exchange
WCS	Western Canadian Select	SAGD	steam-assisted gravity drainage
HSB	Husky Synthetic Blend		
OPEC	Organization of Petroleum Exporting Countries		
OPEC+	OPEC and a group of 10 non-OPEC members		
FPSO	Floating production storage and offloading unit		

SPECIFIED FINANCIAL MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS including Operating Margin, Operating Margin for the Upstream or Downstream operations, Operating Margin by asset, Total Integration Costs, Adjusted Funds Flow, Free Funds Flow, Excess Free Funds Flow, Gross Margin, Refining Margin, Forward-looking Integration Costs, and Netbacks (including the total netbacks per BOE).

These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation, if applicable, of each specified financial measure is presented in this Advisory and may also be presented in the Operating and Financial Results or Liquidity and Capital Resources sections of this MD&A.

Operating Margin

Operating Margin and Operating Margin by asset are non-GAAP financial measures, and Operating Margin for the Upstream or Downstream segment are specified financial measures. These are used to provide a consistent measure of the cash generating performance of our operations and assets for comparability of our underlying financial performance between periods. Operating Margin is defined as revenues less purchased product, transportation and blending, operating expenses, plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Margin.

	Three Months Ended September 30, 2022			Three Months Ended June 30, 2022			Three Months Ended March 31, 2022 [1]			**Nine Months Ended September 30, 2022**		
($ millions)	**Upstream [2]**	**Downstream [2]**	**Total**	Upstream	Downstream	Total	Upstream	Downstream	Total	**Upstream [2]**	**Downstream [2]**	**Total**
Revenues												
Gross Sales	**10,238**	**11,078**	**21,316**	11,685	10,844	22,529	10,897	8,247	19,144	**32,820**	**30,169**	**62,989**
Less: Royalties	**1,226**	**—**	**1,226**	1,582	—	1,582	1,185	—	1,185	**3,993**	**—**	**3,993**
	9,012	**11,078**	**20,090**	10,103	10,844	20,947	9,712	8,247	17,959	**28,827**	**30,169**	**58,996**
Expenses												
Purchased Product	**2,397**	**9,882**	**12,279**	1,461	9,046	10,507	1,818	6,946	8,764	**5,676**	**25,874**	**31,550**
Transportation and Blending	**2,800**	**3**	**2,803**	3,238	(2)	3,236	3,194	2	3,196	**9,232**	**3**	**9,235**
Operating	**915**	**780**	**1,695**	1,010	866	1,876	909	645	1,554	**2,834**	**2,291**	**5,125**
Realized (Gain) Loss on Risk Management	**51**	**(77)**	**(26)**	563	87	650	871	110	981	**1,485**	**120**	**1,605**
Operating Margin	**2,849**	**490**	**3,339**	3,831	847	4,678	2,920	544	3,464	**9,600**	**1,881**	**11,481**

(1) *Prior period results were revised to more appropriately reflect the cost of blending. See Note 3 of the interim Consolidated Financial Statements for further details.*

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

	2021																	
	Upstream						**Downstream**						**Total**					
	Year-to-Date		Three Months Ended				Year-to-Date		Three Months Ended				Year-to-Date		Three Months Ended			
($ millions)	Q4	Q3	Q4	Q3	Q2	Q1	Q4	Q3	Q4	Q3	Q2	Q1	Q4	Q3	Q4	Q3	Q2	Q1
Revenues																		
Gross Sales [1]	27,844	19,607	8,237	7,354	6,128	6,125	26,673	18,538	8,135	7,530	6,318	4,690	54,517	38,145	16,372	14,884	12,446	10,815
Less: Royalties	2,454	1,639	815	733	533	373	—	—	—	—	—	—	2,454	1,639	815	733	533	373
	25,390	17,968	7,422	6,621	5,595	5,752	26,673	18,538	8,135	7,530	6,318	4,690	52,063	36,506	15,557	14,151	11,913	10,442
Expenses																		
Purchased Product (1)	4,059	2,861	1,198	1,074	717	1,070	23,526	16,178	7,348	6,708	5,502	3,968	27,585	19,039	8,546	7,782	6,219	5,038
Transportation and Blending (1)	8,714	6,115	2,599	2,137	2,006	1,972	—	—	—	—	—	—	8,714	6,115	2,599	2,137	2,006	1,972
Operating	3,241	2,376	865	800	791	785	2,258	1,569	689	537	515	517	5,499	3,945	1,554	1,337	1,306	1,302
Realized (Gain) Loss on Risk Management	788	586	202	168	188	230	104	48	56	17	10	21	892	634	258	185	198	251
Operating Margin	8,588	6,030	2,558	2,442	1,893	1,695	785	743	42	268	291	184	9,373	6,773	2,600	2,710	2,184	1,879

(1) *Prior period results were revised for a change in presentation of product swaps and certain third-party purchases used in blending and optimization activities, and to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.*

	Three Months Ended December 31, 2020			Three Months Ended September 30, 2020		
($ millions)	Upstream	Downstream	Total	Upstream	Downstream	Total
Revenues						
Gross Sales	2,749	1,124	3,873	2,746	1,252	3,998
Less: Royalties	143	—	143	153	—	153
	2,606	1,124	3,730	2,593	1,252	3,845
Expenses						
Purchased Product	334	1,016	1,350	389	1,133	1,522
Transportation and Blending	1,149	—	1,149	1,036	—	1,036
Operating	389	192	581	367	187	554
Realized (Gain) Loss on Risk Management	40	(15)	25	137	2	139
Operating Margin	694	(69)	625	664	(70)	594

Operating Margin by Asset

($ millions)	Three Months Ended September 30, 2022			Nine Months Ended September 30, 2022		
	Asia Pacific	**Atlantic**	**Offshore [(1)]**	**Asia Pacific**	**Atlantic**	**Offshore [(1)]**
Revenues						
Gross Sales	**337**	**113**	**450**	**1,083**	**492**	**1,575**
Less: Royalties	**20**	**2**	**22**	**60**	**(4)**	**56**
	317	**111**	**428**	**1,023**	**496**	**1,519**
Expenses						
Transportation and Blending	**—**	**4**	**4**	**—**	**12**	**12**
Operating	**32**	**53**	**85**	**88**	**146**	**234**
Operating Margin	**285**	**54**	**339**	**935**	**338**	**1,273**

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

($ millions)	Three Months Ended September 30, 2021			Nine Months Ended September 30, 2021		
	Asia Pacific	Atlantic	Offshore [(1)]	Asia Pacific	Atlantic	Offshore [(1)]
Revenues						
Gross Sales	336	68	404	965	297	1,262
Less: Royalties	20	4	24	53	21	74
	316	64	380	912	276	1,188
Expenses						
Transportation and Blending	—	3	3	—	10	10
Operating	28	21	49	74	92	166
Operating Margin	288	40	328	838	174	1,012

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

Total Integration Costs

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

($ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2022	2021	**2022**	2021
Integration Costs [(1)]	**24**	45	**76**	302
Capitalized Integration Costs [(2)]	**1**	15	**5**	49
Total Integration Costs	**25**	60	**81**	351

(1) See Note 7 of the interim Consolidated Statements of Earnings (Loss).
(2) Included in capital expenditures on the interim Consolidated Statements of Cash Flows.

Adjusted Funds Flow, Free Funds Flow and Excess Free Funds Flow

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

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

Excess Free Funds Flow is a non-GAAP financial measure used by the Company to deliver shareholder returns and allocate capital according to our shareholder returns and capital allocation framework. Excess Free Funds Flow is defined as Free Funds Flow minus base dividends paid on common shares, dividends paid on preferred shares, other uses of cash (including settlement of decommissioning liabilities and principal repayment of leases), and acquisition costs, plus proceeds from or payments related to divestitures. Excess Free Funds Flow was a new metric as of June 30, 2022.

	2022			2021				2020	
($ millions)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Cash From (Used in) Operating Activities	**4,089**	2,979	1,365	2,184	2,138	1,369	228	250	732
(Add) Deduct:									
Settlement of Decommissioning Liabilities	**(55)**	(27)	(19)	(35)	(38)	(18)	(11)	(6)	(3)
Net Change in Non-Cash Working Capital	**1,193**	(92)	(1,199)	271	(166)	(430)	(902)	(77)	328
Adjusted Funds Flow	**2,951**	3,098	2,583	1,948	2,342	1,817	1,141	333	407
Capital Investment	**866**	822	746	835	647	534	547	242	148
Free Funds Flow	**2,085**	2,276	1,837	1,113	1,695	1,283	594	91	259
Add (Deduct):									
Base Dividends Paid on Common Shares	**(205)**	(207)	(69)	(70)	(35)	(36)	(35)		
Dividends Paid on Preferred Shares	**(9)**	(8)	(9)	(8)	(9)	(8)	(9)		
Settlement of Decommissioning Liabilities	**(55)**	(27)	(19)	(35)	(38)	(18)	(11)		
Principal Repayment of Leases	**(78)**	(75)	(75)	(78)	(70)	(77)	(75)		
Acquisitions, Net of Cash Acquired	**(389)**	(1)	—	—	—	—	(7)		
Proceeds From Divestitures, Net of Cash Paid	**407**	62	950	247	83	100	5		
Excess Free Funds Flow	**1,756**	2,020	2,615	1,169	1,626	1,244	462		

	Nine Months Ended September 30,	
($ millions)	**2022**	2021
Cash From (Used in) Operating Activities	**8,433**	3,735
(Add) Deduct:		
Settlement of Decommissioning Liabilities	**(101)**	(67)
Net Change in Non-Cash Working Capital	**(98)**	(1,498)
Adjusted Funds Flow	**8,632**	5,300
Capital Investment	**2,434**	1,728
Free Funds Flow	**6,198**	3,572

Gross Margin, Refining Margin and Unit Operating Expense

Gross Margin and Refining Margin are non-GAAP financial measures, or contain a non-GAAP financial measure, used to evaluate the performance of our downstream operations. We define Gross Margin as revenues less purchased product. We define Refining Margin as Gross Margin divided by barrels of crude oil throughput. Unit Operating Expenses are specified financial measures used to evaluate the performance of our upstream and downstream operations. We define Unit Operating Expense as operating expenses divided by barrels of crude oil throughput in our downstream operations.

Canadian Manufacturing

($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Manufacturing [2]
	Three Months Ended September 30, 2022				
	Basis of Refining Margin Calculation				
Revenues	951	600	1,551	(73)	1,478
Purchased Product	694	498	1,192	(100)	1,092
Gross Margin	257	102	359	27	386

	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
	Operating Statistics		
Heavy Crude Oil Throughput (Mbbls/d)	71.3	27.2	98.5
Refining Margin ($/bbl)	38.17	40.39	38.78

(1) Includes ethanol and crude-by-rail operations, and marketing activities.
(2) These amounts, excluding gross margin, are found in Note 1 of the interim Consolidated Financial Statements.

($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Manufacturing [2]
	Nine Months Ended September 30, 2022				
	Basis of Refining Margin Calculation				
Revenues	2,651	1,027	3,678	365	4,043
Purchased Product	2,088	851	2,939	253	3,192
Gross Margin	563	176	739	112	851

	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
	Operating Statistics		
Heavy Crude Oil Throughput (Mbbls/d)	68.8	23.7	92.5
Refining Margin ($/bbl)	30.08	27.34	29.37

(1) Includes ethanol and crude-by-rail operations, and marketing activities.
(2) These amounts, excluding gross margin, are found in Note 1 of the interim Consolidated Financial Statements.

($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Manufacturing [2]
	Three Months Ended September 30, 2021				
	Basis of Refining Margin Calculation				
Revenues	684	278	962	253	1,215
Purchased Product	556	230	786	200	986
Gross Margin	128	48	176	53	229

	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
	Operating Statistics		
Heavy Crude Oil Throughput (Mbbls/d)	81.2	27.1	108.3
Refining Margin ($/bbl)	16.93	19.29	17.57

(1) Includes ethanol and crude-by-rail operations, and marketing activities.
(2) These amounts, excluding gross margin, are found in Note 1 of the interim Consolidated Financial Statements.

	Nine Months Ended September 30, 2021				
	Basis of Refining Margin Calculation				
($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other (1)	Total Canadian Manufacturing (2)
Revenues	1,811	611	2,422	687	3,109
Purchased Product	1,449	487	1,936	488	2,424
Gross Margin	362	124	486	199	685

	Operating Statistics		
	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
Heavy Crude Oil Throughput (Mbbls/d)	78.6	27.4	106.0
Refining Margin ($/bbl)	16.91	16.58	16.78

(1) Includes ethanol and crude-by-rail operations, and marketing activities.
(2) These amounts, excluding gross margin, are found in Note 1 of the interim Consolidated Financial Statements.

U.S. Manufacturing

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2022**	2021	**2022**	2021
Revenues (1)	**8,719**	5,723	**23,702**	13,889
Purchased Product (1)	**7,944**	5,171	**20,365**	12,320
Gross Margin	**775**	552	**3,337**	1,569
Crude Oil Throughput (Mbbls/d)	**435.0**	445.8	**405.3**	415.0
Refining Margin ($/bbl)	**18.98**	13.45	**29.94**	13.84

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

Retail

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2022**	2021	**2022**	2021
Revenues (1)	**881**	592	**2,424**	1,540
Purchased Product (1)	**846**	551	**2,317**	1,434
Gross Margin	**35**	41	**107**	106

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

Per Unit DD&A

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

Netback Reconciliations

Netback is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring operating performance and is also presented on a per-unit basis. Our Netback calculation is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook. Netbacks per BOE 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, and netback per BOE is divided by sales volumes. Netbacks do not reflect non-cash write-downs or reversals of product inventory until it is realized when the product is sold. The sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Condensate is blended with crude oil to transport it to market.

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

Total Production

Upstream Financial Results

Three Months Ended September 30, 2022 ($ millions)	Total Upstream (1)	Adjustments: Condensate	Adjustments: Third-Party Sourced	Adjustments: Internal Consumption (2)	Adjustments: Equity Adjustment (3)	Adjustments: Other (4)	Basis of Netback Calculation: Total Upstream
Gross Sales	**10,238**	**(2,333)**	**(2,346)**	**(235)**	**63**	**(113)**	**5,274**
Royalties	**1,226**	**—**	**—**		**25**	**(6)**	**1,245**
Purchased Product	**2,397**	**—**	**(2,346)**		**—**	**(51)**	**—**
Transportation and Blending	**2,800**	**(2,333)**	**—**		**—**	**(24)**	**443**
Operating	**915**	**—**	**—**	**(235)**	**6**	**3**	**689**
Netback	**2,900**	**—**	**—**	**—**	**32**	**(35)**	**2,897**
Realized (Gain) Loss on Risk Management	**51**	**—**	**—**		**—**	**—**	**51**
Operating Margin	**2,849**	**—**	**—**	**—**	**32**	**(35)**	**2,846**

Three Months Ended September 30, 2021 ($ millions)	Total Upstream (1)	Adjustments: Condensate	Adjustments: Third-Party Sourced	Adjustments: Internal Consumption (2)	Adjustments: Equity Adjustment (3)	Adjustments: Other (4)	Basis of Netback Calculation: Total Upstream
Gross Sales (5)	7,354	(1,734)	(1,007)	(175)	60	(49)	4,449
Royalties	733	—	—	—	11	—	744
Purchased Product (5)	1,074	—	(1,007)	—	—	(67)	—
Transportation and Blending	2,137	(1,734)	—	—	—	20	423
Operating	800	—	—	(175)	6	(11)	620
Netback	2,610	—	—	—	43	9	2,662
Realized (Gain) Loss on Risk Management	168	—	(2)	—	—	—	166
Operating Margin	2,442	—	2	—	43	9	2,496

(1) These amounts, excluding netback, are 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 in the consolidated financial statements.
(4) Other includes construction, transportation and blending and third-party processing margin.
(5) Prior period results were revised for a change in presentation of product swaps and certain third-party purchases used in blending and optimization activities, and to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

Nine Months Ended September 30, 2022 ($ millions)	Total Upstream [1]	Adjustments					Basis of Netback Calculation
		Condensate	Third-Party Sourced	Internal Consumption [2]	Equity Adjustment [3]	Other [4]	Total Upstream
Gross Sales	**32,820**	**(7,892)**	**(5,461)**	**(821)**	**194**	**(306)**	**18,534**
Royalties	**3,993**	**—**	**—**		**89**	**(11)**	**4,071**
Purchased Product	**5,676**	**—**	**(5,461)**		**—**	**(215)**	**—**
Transportation and Blending	**9,232**	**(7,892)**	**—**		**—**	**(35)**	**1,305**
Operating	**2,834**	**—**	**—**	**(821)**	**21**	**(28)**	**2,006**
Netback	**11,085**	**—**	**—**	**—**	**84**	**(17)**	**11,152**
Realized (Gain) Loss on Risk Management	**1,485**	**—**	**(8)**		**—**	**—**	**1,477**
Operating Margin	**9,600**	**—**	**8**	**—**	**84**	**(17)**	**9,675**

Nine Months Ended September 30, 2021 ($ millions)	Total Upstream [1]	Adjustments					Basis of Netback Calculation
		Condensate	Third-Party Sourced	Internal Consumption [2]	Equity Adjustment [3]	Other [4]	Total Upstream
Gross Sales [5]	19,607	(4,894)	(2,682)	(469)	162	(244)	11,480
Royalties	1,639	—	—	—	23	—	1,662
Purchased Product [5]	2,861	—	(2,682)	—	—	(179)	—
Transportation and Blending	6,115	(4,894)	—	—	—	—	1,221
Operating	2,376	—	—	(469)	18	(33)	1,892
Netback	6,616	—	—	—	121	(32)	6,705
Realized (Gain) Loss on Risk Management	586	—	(2)	—	—	—	584
Operating Margin	6,030	—	2	—	121	(32)	6,121

(1) These amounts, excluding netback, are 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 in the consolidated financial statements.

(4) Other includes construction, transportation and blending and third-party processing margin.

(5) Prior period results were revised for a change in presentation of product swaps and certain third-party purchases used in blending and optimization activities, and to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

Oil Sands

Three Months Ended September 30, 2022 ($ millions)	Foster Creek	Christina Lake	Sunrise	Other Oil Sands (1)	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
	Basis of Netback Calculation						
Gross Sales	1,486	1,847	218	929	4,480	4	4,484
Royalties	432	594	18	82	1,126	4	1,130
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	199	137	36	38	410	—	410
Operating	224	209	49	229	711	4	715
Netback	631	907	115	580	2,233	(4)	2,229
Realized (Gain) Loss on Risk Management							42
Operating Margin							2,187

Three Months Ended September 30, 2022 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced	Other (2)	Total Oil Sands (3)
Gross Sales	4,484	2,333	1,882	79	8,778
Royalties	1,130	—	—	6	1,136
Purchased Product	—	—	1,882	51	1,933
Transportation and Blending	410	2,333	—	15	2,758
Operating	715	—	—	(26)	689
Netback	2,229	—	—	33	2,262
Realized (Gain) Loss on Risk Management	42	—	—	—	42
Operating Margin	2,187	—	—	33	2,220

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

Three Months Ended September 30, 2021 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced	Other (2)	Total Oil Sands (3)
Gross Sales (4)	3,782	1,734	562	39	6,117
Royalties	669	—	—	—	669
Purchased Product (4)	—	—	562	67	629
Transportation and Blending	400	1,734	—	(20)	2,114
Operating	615	—	—	1	616
Netback	2,098	—	—	(9)	2,089
Realized (Gain) Loss on Risk Management	166	—	—	—	166
Operating Margin	1,932	—	—	(9)	1,923

(1) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.
(2) Other includes construction, transportation and blending margin.
(3) These amounts, excluding netback, are found in Note 1 of the interim Consolidated Financial Statements.
(4) Prior period results were revised for a change in presentation of product swaps and certain third-party purchases used in blending and optimization activities, and to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

Nine Months Ended September 30, 2022 ($ millions)	Basis of Netback Calculation						
	Foster Creek	Christina Lake	Sunrise	Other Oil Sands (1)	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
Gross Sales	5,441	6,498	728	3,222	15,889	14	15,903
Royalties	1,445	1,900	46	302	3,693	5	3,698
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	559	431	93	110	1,193	—	1,193
Operating	676	677	133	703	2,189	17	2,206
Netback	2,761	3,490	456	2,107	8,814	(8)	8,806
Realized (Gain) Loss on Risk Management							1,468
Operating Margin							7,338

Nine Months Ended September 30, 2022 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced	Other (2)	Total Oil Sands (3)
Gross Sales	15,903	7,892	4,001	248	28,044
Royalties	3,698	—	—	11	3,709
Purchased Product	—	—	4,001	215	4,216
Transportation and Blending	1,193	7,892	—	29	9,114
Operating	2,206	—	—	(9)	2,197
Netback	8,806	—	—	2	8,808
Realized (Gain) Loss on Risk Management	1,468			—	1,468
Operating Margin	7,338	—	—	2	7,340

Nine Months Ended September 30, 2021 ($ millions)	Basis of Netback Calculation						
	Foster Creek	Christina Lake	Sunrise	Other Oil Sands (1)	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
Gross Sales	3,037	3,674	427	2,309	9,447	9	9,456
Royalties	487	733	13	228	1,461	1	1,462
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	520	386	83	165	1,154	—	1,154
Operating	517	506	118	628	1,769	15	1,784
Netback	1,513	2,049	213	1,288	5,063	(7)	5,056
Realized (Gain) Loss on Risk Management							584
Operating Margin							4,472

Nine Months Ended September 30, 2021 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced	Other (2)	Total Oil Sands (3)
Gross Sales (4)	9,456	4,894	1,569	191	16,110
Royalties	1,462	—	—	—	1,462
Purchased Product (4)	—	—	1,569	179	1,748
Transportation and Blending	1,154	4,894	—	—	6,048
Operating	1,784	—	—	9	1,793
Netback	5,056	—	—	3	5,059
Realized (Gain) Loss on Risk Management	584	—	—	—	584
Operating Margin	4,472	—	—	3	4,475

(1) Includes Tucker, Lloydminster thermal and Lloydminster conventional heavy oil assets. The Tucker asset was sold on January 31, 2022.
(2) Other includes construction, transportation and blending margin.
(3) These amounts, excluding netback, are found in Note 1 of the interim Consolidated Financial Statements.
(4) Prior period results were revised for a change in presentation of product swaps and certain third-party purchases used in blending and optimization activities, and to more appropriately reflect the cost of blending. See the Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

Conventional

Three Months Ended September 30, 2022 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	512	464	34	1,010
Royalties	68	—	—	68
Purchased Product	—	464	—	464
Transportation and Blending	29	—	9	38
Operating	137	—	4	141
Netback	278	—	21	299
Realized (Gain) Loss on Risk Management	9	—	—	9
Operating Margin	269	—	21	290

Three Months Ended September 30, 2021 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other [1]	Conventional [2]
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

Nine Months Ended September 30, 2022 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	1,683	1,460	58	3,201
Royalties	228	—	—	228
Purchased Product	—	1,460	—	1,460
Transportation and Blending	100	—	6	106
Operating	385	—	18	403
Netback	970	—	34	1,004
Realized (Gain) Loss on Risk Management	9	8	—	17
Operating Margin	961	(8)	34	987

Nine Months Ended September 30, 2021 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other [1]	Conventional [2]
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

(1) Reflects Operating Margin from processing facilities.
(2) These amounts, excluding netback, are found in Note 1 of the interim Consolidated Financial Statements.

Offshore

Three Months Ended September 30, 2022 ($ millions)	Basis of Netback Calculation					Adjustments		
	China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment [1]	Other [2]	Total Offshore [3]
Gross Sales	337	63	400	113	513	(63)	—	450
Royalties	20	25	45	2	47	(25)	—	22
Purchased Product	—	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	4	4	—	—	4
Operating	28	10	38	34	72	(6)	19	85
Netback	289	28	317	73	390	(32)	(19)	339
Realized (Gain) Loss on Risk Management					—	—	—	—
Operating Margin					390	(32)	(19)	339

Three Months Ended September 30, 2021 ($ millions)	Basis of Netback Calculation					Adjustment	
	China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment [1]	Total Offshore [3]
Gross Sales	336	60	396	68	464	(60)	404
Royalties	20	11	31	4	35	(11)	24
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	3	3	—	3
Operating	27	7	34	21	55	(6)	49
Netback	289	42	331	40	371	(43)	328
Realized (Gain) Loss on Risk Management					—	—	—
Operating Margin					371	(43)	328

Three Months Ended June 30, 2021 ($ millions)	Basis of Netback Calculation					Adjustment	
	China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment [1]	Total Offshore [3]
Gross Sales	308	50	358	119	477	(50)	427
Royalties	16	5	21	9	30	(5)	25
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	3	3	—	3
Operating	23	8	31	35	66	(7)	59
Netback	269	37	306	72	378	(38)	340
Realized (Gain) Loss on Risk Management					—	—	—
Operating Margin					378	(38)	340

Three Months Ended March 31, 2021 ($ millions)	Basis of Netback Calculation					Adjustment	
	China	Indonesia [1]	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment [1]	Total Offshore [3]
Gross Sales	321	52	373	110	483	(52)	431
Royalties	17	7	24	8	32	(7)	25
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	4	4	—	4
Operating	21	6	27	36	63	(5)	58
Netback	283	39	322	62	384	(40)	344
Realized (Gain) Loss on Risk Management					—	—	—
Operating Margin					384	(40)	344

(1) Revenues and expenses related to the HCML joint venture are accounted for using the equity method in the consolidated financial statements.
(2) Relates to costs in the Atlantic.
(3) These amounts, excluding netback, are found in Note 1 of the interim Consolidated Financial Statements.

Nine Months Ended September 30, 2022 ($ millions)	Basis of Netback Calculation					Adjustments		
	China	Indonesia (1)	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment (1)	Other (2)	Total Offshore (3)
Gross Sales	**1,083**	**194**	**1,277**	**492**	**1,769**	**(194)**	**—**	**1,575**
Royalties	**60**	**89**	**149**	**(4)**	**145**	**(89)**	**—**	**56**
Purchased Product	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Transportation and Blending	**—**	**—**	**—**	**12**	**12**	**—**	**—**	**12**
Operating	**75**	**34**	**109**	**127**	**236**	**(21)**	**19**	**234**
Netback	**948**	**71**	**1,019**	**357**	**1,376**	**(84)**	**(19)**	**1,273**
Realized (Gain) Loss on Risk Management					**—**	**—**	**—**	**—**
Operating Margin					**1,376**	**(84)**	**(19)**	**1,273**

Nine Months Ended September 30, 2021 ($ millions)	Basis of Netback Calculation					Adjustment	
	China	Indonesia (1)	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment (1)	Total Offshore (2)
Gross Sales	965	162	1,127	297	1,424	(162)	1,262
Royalties	53	23	76	21	97	(23)	74
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	10	10	—	10
Operating	71	21	92	92	184	(18)	166
Netback	841	118	959	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 in the consolidated financial statements.
(2) Relates to costs in the Atlantic.
(3) These amounts, excluding netback, are 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)	Three Months Ended September 30, 2022	2021	Nine Months Ended September 30, 2022	2021
Oil Sands				
Foster Creek	**180.7**	206.3	**190.9**	173.5
Christina Lake	**247.2**	238.1	**247.8**	230.5
Sunrise (2)	**29.7**	25.5	**26.3**	23.6
Other Oil Sands	**120.4**	143.2	**118.8**	143.8
Total Oil Sands (2)	**578.0**	613.1	**583.8**	571.4
Conventional	**126.2**	131.4	**128.0**	136.2
Sales before Internal Consumption	**704.2**	744.5	**711.8**	707.6
Less: Internal Consumption (3)	**(80.7)**	(84.0)	**(84.3)**	(85.2)
Sales after Internal Consumption	**623.5**	660.5	**627.5**	622.4
Offshore				
Asia Pacific - China	**45.4**	49.8	**48.6**	50.1
Asia Pacific - Indonesia	**10.1**	10.0	**9.7**	9.4
Asia Pacific - Total	**55.5**	59.8	**58.3**	59.5
Atlantic	**7.8**	7.8	**12.6**	12.6
Total Offshore	**63.3**	67.6	**70.9**	72.1
Total Sales	**686.8**	728.1	**698.4**	694.5

(1) Presented on dry bitumen basis.
(2) Sunrise sales volumes have been re-presented to reflect a change in classification of marketing activities for the first and second quarters of 2021.
(3) Less natural gas volumes used for internal consumption by the Oil Sands segment.

The following tables have been re-presented for the first, second, third and fourth quarters of 2021 and the first quarter of 2022 to more appropriately reflect the cost of blending at our Lloydminster Thermal and Lloydminster conventional heavy oil assets, which resulted in a reclassification of costs between purchased products and transportation and blending. In addition, the tables were also re-presented for the first, second and third quarters of 2021 for a change in the presentation of product swaps and certain third-party purchases used in blending and optimization activities and a change in the classification of marketing activities at Sunrise. Sunrise sales volumes, gross sales, royalties, transportation and blending, and operating expenses have been re-presented. See Adjustments to the Interim Consolidated Statements of Earnings (Loss) below for further details.

Upstream Financial Results

		Adjustments					Basis of Netback Calculation
Three Months Ended March 31, 2022 ($ millions)	Total Upstream	Condensate	Third-Party Sourced	Internal Consumption (1)	Equity Adjustment (2)	Other (3)	Total Upstream
Gross Sales	**10,897**	(2,758)	(1,750)	(239)	61	(76)	**6,135**
Royalties	**1,185**	—	—	—	28	—	**1,213**
Purchased Product	**1,818**	—	(1,750)	—	—	(68)	**—**
Transportation and Blending	**3,194**	(2,758)	—	—	—	1	**437**
Operating	**909**	—	—	(239)	7	(21)	**656**
Netback	**3,791**	**—**	**—**	**—**	**26**	**12**	**3,829**
Realized (Gain) Loss on Risk Management	**871**	—	(4)	—	—	—	**867**
Operating Margin	**2,920**	**—**	**4**	**—**	**26**	**12**	**2,962**

		Adjustments					Basis of Netback Calculation
Year Ended December 31, 2021 ($ millions)	Total Upstream	Condensate	Third-party Sourced	Internal Consumption (1)	Equity Adjustment (2)	Other (3)	Total Upstream
Gross Sales	**27,844**	(7,095)	(3,761)	(710)	224	(390)	**16,112**
Royalties	**2,454**	—	—	—	52	—	**2,506**
Purchased Product	**4,059**	—	(3,761)	—	—	(298)	**—**
Transportation and Blending	**8,714**	(7,095)	—	—	—	—	**1,619**
Operating	**3,241**	—	(8)	(710)	25	(36)	**2,512**
Netback	**9,376**	**—**	**8**	**—**	**147**	**(56)**	**9,475**
Realized (Gain) Loss on Risk Management	**788**	—	(2)	—	—	—	**786**
Operating Margin	**8,588**	**—**	**10**	**—**	**147**	**(56)**	**8,689**

		Adjustments					Basis of Netback Calculation
Three Months Ended December 31, 2021 ($ millions)	Total Upstream	Condensate	Third-Party Sourced	Internal Consumption (1)	Equity Adjustment (2)	Other (3)	Total Upstream
Gross Sales	**8,237**	(2,201)	(1,079)	(241)	62	(146)	**4,632**
Royalties	**815**	—	—	—	29	—	**844**
Purchased Product	**1,198**	—	(1,079)	—	—	(119)	**—**
Transportation and Blending	**2,599**	(2,201)	—	—	—	—	**398**
Operating	**865**	—	(8)	(241)	7	(3)	**620**
Netback	**2,760**	**—**	**8**	**—**	**26**	**(24)**	**2,770**
Realized (Gain) Loss on Risk Management	**202**	**—**	**—**	**—**	**—**	**—**	**202**
Operating Margin	**2,558**	**—**	**8**	**—**	**26**	**(24)**	**2,568**

		Adjustments					Basis of Netback Calculation
Three Months Ended June 30, 2021 ($ millions)	Total Upstream	Condensate	Third-Party Sourced	Internal Consumption (1)	Equity Adjustment (2)	Other (3)	Total Upstream
Gross Sales	**6,128**	(1,620)	(651)	(145)	50	(105)	**3,657**
Royalties	**533**	—	—	—	5	—	**538**
Purchased Product	**717**	—	(651)	—	—	(66)	**—**
Transportation and Blending	**2,006**	(1,620)	—	—	—	(17)	**369**
Operating	**791**	—	—	(145)	7	(11)	**642**
Netback	**2,081**	**—**	**—**	**—**	**38**	**(11)**	**2,108**
Realized (Gain) Loss on Risk Management	**188**	—	—	—	—	—	**188**
Operating Margin	**1,893**	**—**	**—**	**—**	**38**	**(11)**	**1,920**

Three Months Ended March 31, 2021 ($ millions)	Total Upstream	Adjustments: Condensate	Third-Party Sourced	Internal Consumption (1)	Equity Adjustment (2)	Other (3)	Basis of Netback Calculation: Total Upstream
Gross Sales	6,125	(1,540)	(1,024)	(149)	52	(90)	3,374
Royalties	373	—	—	—	7	—	380
Purchased Product	1,070	—	(1,024)	—	—	(46)	—
Transportation and Blending	1,972	(1,540)	—	—	—	(3)	429
Operating	785	—	—	(149)	5	(11)	630
Netback	1,925	—	—	—	40	(30)	1,935
Realized (Gain) Loss on Risk Management	230	—	—	—	—	—	230
Operating Margin	1,695	—	—	—	40	(30)	1,705

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

Oil Sands

Three Months Ended March 31, 2022 ($ millions)	Basis of Netback Calculation: Total Oil Sands	Adjustments: Condensate	Third-party Sourced	Other (1)	Total Oil Sands
Gross Sales	5,264	2,758	1,144	52	9,218
Royalties	1,082	—	—	—	1,082
Purchased Product	—	—	1,144	68	1,212
Transportation and Blending	397	2,758	—	1	3,156
Operating	687	—	—	15	702
Netback	3,098	—	—	(32)	3,066
Realized (Gain) Loss on Risk Management	867	—	—	—	867
Operating Margin	2,231	—	—	(32)	2,199

Year Ended December 31, 2021 ($ millions)	Basis of Netback Calculation: Total Oil Sands	Adjustments: Condensate	Third-party Sourced	Other (1)	Total Oil Sands
Gross Sales	13,297	7,095	2,106	329	22,827
Royalties	2,196	—	—	—	2,196
Purchased Product	—	—	2,106	298	2,404
Transportation and Blending	1,530	7,095	—	—	8,625
Operating	2,437	—	—	14	2,451
Netback	7,134	—	—	17	7,151
Realized (Gain) Loss on Risk Management	786	—	—	—	786
Operating Margin	6,348	—	—	17	6,365

Three Months Ended December 31, 2021 ($ millions)	Basis of Netback Calculation: Total Oil Sands	Adjustments: Condensate	Third-party Sourced	Other (1)	Total Oil Sands
Gross Sales	3,841	2,201	537	138	6,717
Royalties	734	—	—	—	734
Purchased Product	—	—	537	119	656
Transportation and Blending	376	2,201	—	—	2,577
Operating	653	—	—	5	658
Netback	2,078	—	—	14	2,092
Realized (Gain) Loss on Risk Management	202	—	—	—	202
Operating Margin	1,876	—	—	14	1,890

Three Months Ended June 30, 2021 ($ millions)	Basis of Netback Calculation: Total Oil Sands	Adjustments: Condensate	Third-party Sourced	Other (1)	Total Oil Sands
Gross Sales	3,005	1,620	364	86	5,075
Royalties	469	—	—	—	469
Purchased Product	—	—	364	66	430
Transportation and Blending	347	1,620	—	17	1,984
Operating	589	—	—	3	592
Netback	1,600	—	—	—	1,600
Realized (Gain) Loss on Risk Management	189	—	—	—	189
Operating Margin	1,411	—	—	—	1,411

Three Months Ended March 31, 2021 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced	Other [1]	Total Oil Sands
Gross Sales	2,669	1,540	643	66	4,918
Royalties	324	—	—	—	324
Purchased Product	—	—	643	46	689
Transportation and Blending	407	1,540	—	3	1,950
Operating	580	—	—	5	585
Netback	1,358	—	—	12	1,370
Realized (Gain) Loss on Risk Management	229	—	—	—	229
Operating Margin	1,129	—	—	12	1,141

(1) Other includes construction, transportation and blending margin.

Adjustments to the Interim Consolidated Statements of Earnings (Loss)

Certain comparative information presented in the Consolidated Statements of Earnings (Loss) within the Oil Sands segment and Corporate and Eliminations segment was revised. See Consolidated Financial Statements and Note 3 of the interim Consolidated Financial Statements for further details.

During the three months ended December 31, 2021, the Company made adjustments to more appropriately record certain third-party purchases used for blending and optimization activities and to ensure consistent treatment of product swaps. As a result, revenues and purchased product increased with no impact to net earnings (loss), segment income (loss), cash flows or financial position. Refer to the annual Consolidated Financial Statements for the year ended December 31, 2021, for further details.

During the three months ended June 30, 2022, the Company made adjustments to more appropriately reflect the cost of blending at our Lloydminster thermal and Lloydminster conventional heavy oil assets, which resulted in a reclassification of costs between purchased product and transportation and blending. An associated elimination entry was recorded in our Corporate and Eliminations segment to represent the change in the value of condensate that was extracted at our Canadian Manufacturing operations and sold back to the Oil Sands segment. As a result, purchased product decreased and transportation and blending increased, with no impact to net earnings (loss), segment income (loss), cash flows or financial position. Refer to the interim Consolidated Financial Statements for the periods ended June 30, 2022, for further details.

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

($ millions)	Three Months Ended March 31, 2021			Three Months Ended June 30, 2021			Three Months Ended September 30, 2021			Three Months Ended December 31, 2021			Three Months Ended March 31, 2022		
	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**
Oil Sands Segment															
Gross Sales	4,775	143	**4,918**	5,015	60	**5,075**	6,114	3	**6,117**	6,717	—	**6,717**	9,218	—	**9,218**
Purchased Product (1)(2)	718	(29)	**689**	574	(144)	**430**	822	(193)	**629**	868	(212)	**656**	1,483	(271)	**1,212**
Transportation and Blending	1,778	172	**1,950**	1,780	204	**1,984**	1,918	196	**2,114**	2,365	212	**2,577**	2,885	271	**3,156**
Corporate and Eliminations Segment															
Purchased Product	(973)	138	**(835)**	(1,110)	146	**(964)**	(1,244)	153	**(1,091)**	(1,561)	192	**(1,369)**	(1,497)	215	**(1,282)**
Transportation and Blending	(15)	(138)	**(153)**	(6)	(146)	**(152)**	(18)	(153)	**(171)**	(8)	(192)	**(200)**	(6)	(215)	**(221)**
Consolidated															
Gross Sales	9,523	143	**9,666**	11,110	60	**11,170**	13,431	3	**13,434**	14,541	—	**14,541**	17,383	—	**17,383**
Purchased Product	4,094	109	**4,203**	5,253	2	**5,255**	6,731	(40)	**6,691**	7,197	(20)	**7,177**	7,538	(56)	**7,482**
Transportation and Blending	1,785	34	**1,819**	1,796	58	**1,854**	1,923	43	**1,966**	2,379	20	**2,399**	2,919	56	**2,975**

(1) Revisions include $143 million for the three months ended March 31, 2021, $60 million for the three months ended June 30, 2021, $3 million for the three months ended September 30, 2021, and $nil for the three months ended December 31, 2021 and March 31, 2022, related to adjustments for product swaps and third-party purchases used in blending and optimization activities.

(2) Revisions include $172 million for the three months ended March 31, 2021, $204 million for the three months ended June 30, 2021, $196 million for the three months ended September 30, 2021, $212 million for the three months ended December 31, 2021, and $271 million for the three months ended March 31, 2022, to more appropriately reflect the cost of blending at our Lloydminster thermal and Lloydminster conventional heavy oil assets.

($ millions)	Nine Months Ended September 30, 2021			Twelve Months Ended December 31, 2021		
	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**
Oil Sands Segment						
Gross Sales	15,904	206	**16,110**	22,827	—	**22,827**
Purchased Product (1)(2)	2,114	(366)	**1,748**	3,188	(784)	**2,404**
Transportation and Blending	5,476	572	**6,048**	7,841	784	**8,625**
Corporate and Eliminations Segment						
Purchased Product	(3,327)	437	**(2,890)**	(4,888)	629	**(4,259)**
Transportation and Blending	(39)	(437)	**(476)**	(47)	(629)	**(676)**
Consolidated						
Gross Sales	34,064	206	**34,270**	48,811	—	**48,811**
Purchased Product	16,078	71	**16,149**	23,481	(155)	**23,326**
Transportation and Blending	5,504	135	**5,639**	7,883	155	**8,038**

(1) Revisions include $206 million for the nine months ended September 30, 2021, and $nil for the twelve months ended December 31, 2021, related to adjustments for product swaps and third-party purchases used in blending and optimization activities.

(2) Revisions include $572 million for the nine months ended September 30, 2021, and $784 million for the twelve months ended December 31, 2021, to more appropriately reflect the cost of blending at our Lloydminster thermal and Lloydminster conventional heavy oil assets.