Cenovus Energy Inc.

Management's Discussion and Analysis (unaudited)

For the Periods Ended September 30, 2023

(Canadian Dollars)

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the periods ended September 30, 2023

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, 2023, should be read in conjunction with our September 30, 2023 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2022 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2022 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of November 1, 2023, unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus management ("Management") prepared the MD&A. The Audit Committee of the Cenovus Board of Directors ("the Board"), reviewed and recommended the MD&A for approval by the Board, which occurred on November 1, 2023. Additional information about Cenovus, including our quarterly and annual reports, Annual Information Form ("AIF") and Form 40-F, is available on SEDAR+ at sedarplus.ca, 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 were prepared in Canadian dollars, (which includes references to "dollar" or "$"), except where another currency was 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. We are one of the largest Canadian-based crude oil and natural gas producers, with upstream operations in Canada and the Asia Pacific region, and one of the largest Canadian-based refiners and upgraders, with downstream operations in Canada and the United States ("U.S.").

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, refine, transport and market crude oil, natural gas and refined petroleum products 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.

Our Strategy and Key Priorities for 2023

At Cenovus, our purpose is to energize the world to make people's lives better. Our strategy is focused on maximizing shareholder value through competitive cost structures and optimizing margins, while delivering top-tier safety performance and sustainability leadership. The Company prioritizes Free Funds Flow generation through all price cycles to manage our balance sheet, increase shareholder returns through dividend growth and common share purchases, reinvest in our business and diversify our portfolio. On December 6, 2022, we released our 2023 budget. Our 2023 guidance dated July 26, 2023, is available on our website at cenovus.com. For further details see the Operating and Financial Results section of this MD&A.

In 2023, we are delivering on our strategy through five key objectives.

Top-Tier Safety and Operational Performance

Safe and reliable operations are our number one priority. We strive to ensure safe and reliable operations across our portfolio, including top-tier health and safety performance.

We continue to target improved operating performance including the safe return of the Superior Refinery to full operations and integration of the Toledo Refinery with a focus on demonstrating consistent and reliable performance at all of our operated assets.

Sustainability Leadership

Sustainability has always been deeply engrained in Cenovus's culture. We have established ambitious targets in our five environmental, social and governance ("ESG") focus areas and continue to progress tangible plans to meet these targets. Our five ESG focus areas are:

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

Additional information on Cenovus's efforts and performance across the ESG focus areas, including our ESG targets and plans to achieve them, are available in Cenovus's 2022 ESG report on our website at cenovus.com.

Cost Leadership

We aim to maximize shareholder value through competitive cost structures and optimized margins. While we strive to optimize our cost structure in all areas of our business, one of our focus areas is to optimize infrastructure, reduce operating and capital costs, and reduce GHG emissions at our conventional assets.

Financial Discipline and Free Funds Flow Growth

We are focused on achieving and maintaining targeted debt levels while positioning Cenovus for resiliency through all commodity price cycles. We continue to deliver meaningful returns to shareholders in alignment with our financial and shareholder returns framework.

Returns-Focused Capital Allocation

We continue to take a disciplined approach to allocating capital to projects that generate returns at the bottom of the commodity price cycle and provide opportunities to sustainably grow shareholder returns.

We have materially progressed the West White Rose project to deliver first oil in 2026.

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, 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. These provide 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 converts heavy oil and bitumen into synthetic crude oil, diesel, asphalt and other ancillary products. Cenovus also owns and operates the Bruderheim crude-by-rail terminal and two ethanol plants. The Company's commercial fuels business across Canada is included in this segment. Cenovus markets its production and third-party commodity trading volumes in an effort to use its integrated network of assets to maximize value.
- **U.S. Manufacturing,** includes the refining of crude oil to produce gasoline, diesel, jet fuel, asphalt and other products at the wholly-owned Lima, Superior and Toledo refineries, and the jointly-owned Wood River and Borger refineries (jointly owned with operator Phillips 66). Cenovus also markets some of its own and third-party volumes of refined petroleum products including gasoline, diesel, jet fuel and asphalt.

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 and condensate 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 in the Canadian Manufacturing segment and sold to the Oil Sands segment, and unrealized profits in inventory. Eliminations are recorded based on market prices.

QUARTERLY RESULTS OVERVIEW

The third quarter was highlighted by a number of operational milestones, solid operating performance across our assets and an improved commodity price environment from the second quarter, resulting in strong financial results.

- **Executed on our number one priority.** We delivered safe operations across our integrated upstream and downstream business and strive to continuously improve our safety record.

- **Delivered strong upstream performance.** Upstream production averaged 797.0 thousand BOE per day, compared with 729.9 thousand BOE per day in the second quarter. We substantially returned to full operations in the Conventional segment following significant wildfire activity in the second quarter. In the Oil Sands segment, we delivered reliable operations following planned turnaround activity in the second quarter, with production starting on two new well pads at Foster Creek and completing the ramp up of three new well pads at Foster Creek and Christina Lake. In the Offshore segment, we delivered reliable operations following planned turnaround activity in the Atlantic region and an unplanned outage in China in the second quarter.

- **Achieved Offshore milestones.** The West White Rose project is progressing well with construction approximately 75 percent complete. The Terra Nova floating production, storage and offloading unit ("FPSO") returned to the field in August. Commissioning activities are ongoing with production expected to resume in the fourth quarter. In addition, we achieved first gas production from the MAC field in Indonesia.

- **Well positioned in our downstream operated assets**. Crude oil unit throughput (or "throughput") was 664.3 thousand barrels per day in the quarter, an increase of 126.5 thousand barrels per day from the second quarter. The Toledo Refinery performed well following a safe restart in the second quarter. At the Superior Refinery, the start-up of the fluid catalytic cracking unit ("FCCU") was achieved in early October. Crude utilization in the U.S Manufacturing segment was 88 percent (second quarter – 70 percent). In the Canadian Manufacturing segment, we achieved crude utilization of 98 percent (second quarter – 86 percent). We are well positioned to optimize our integrated network of assets and the heavy oil value chain between our upstream and downstream operations.

- **Improved commodity price environment.** Global crude oil benchmarks strengthened from the second quarter while at the same time the WTI-WCS at Hardisty differential narrowed 14 percent to US$12.91 per barrel. WCS at Hardisty averaged US$69.35 per barrel, an increase from US$58.74 per barrel in the second quarter. Condensate pricing rose from the second quarter; however, not to the same degree as crude oil benchmarks. Benchmark refined product pricing improved from the second quarter, with diesel pricing increasing 11 percent to US$113.77 per barrel and gasoline pricing increasing three percent to US$105.59 per barrel. Feedstock purchased at lower prices in the second quarter positively impacted our U.S. refining margins in the third quarter.

- **Solid financial results.** Cash flow from operating activities was $2.7 billion, an increase from $2.0 billion in the second quarter. Adjusted funds flow was $3.4 billion (second quarter – $1.9 billion) mainly due to an improved commodity price environment and the strong operating results discussed above.

- **Reduced long-term debt.** We purchased US$1.0 billion of long-term debt in the third quarter at a discount of $84 million. Net Debt decreased $391 million to $6.0 billion at September 30, 2023, as we move towards our $4 billion Net Debt target. The decrease was driven by strong financial results, partially offset by shareholder returns and an increase in working capital due primarily to rising commodity prices.

- **Delivered significant cash returns to shareholders.** We returned $1.2 billion to shareholders, composed of $600 million for the partial payment of our common share warrants obligation ("Cenovus Warrants"), the purchase of 13.8 million common shares for $361 million through our NCIB, and $264 million through common share base dividends. On November 1, 2023, the Board declared a fourth quarter base dividend of $0.140 per common share and dividends for our preferred shares of $9 million.

Summary of Quarterly Results

	Nine Months Ended September 30,		2023			2022				2021	
($ millions, except where indicated)	**2023**	2022	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Upstream Production Volumes [1] (MBOE/d)	**768.7**	779.2	**797.0**	729.9	779.0	806.9	777.9	761.5	798.6	825.3	804.8
Downstream Crude Oil Unit Throughput [2] (Mbbls/d)	**554.1**	497.8	**664.3**	537.8	457.9	473.3	533.5	457.3	501.8	469.9	554.1
Downstream Production Volumes (Mbbls/d)	**589.8**	530.9	**706.0**	571.9	487.7	506.3	572.6	482.1	538.0	503.4	590.9
Revenues	**39,070**	52,834	**14,577**	12,231	12,262	14,063	17,471	19,165	16,198	13,726	12,701
Operating Margin [3]	**8,871**	11,481	**4,369**	2,400	2,102	2,782	3,339	4,678	3,464	2,600	2,710
Cash From (Used In) Operating Activities	**4,442**	8,433	**2,738**	1,990	(286)	2,970	4,089	2,979	1,365	2,184	2,138
Adjusted Funds Flow [3]	**6,741**	8,632	**3,447**	1,899	1,395	2,346	2,951	3,098	2,583	1,948	2,342
Per Share - Basic [3] ($)	**3.55**	4.40	**1.82**	1.00	0.73	1.22	1.53	1.57	1.30	0.97	1.16
Per Share - Diluted [3] ($)	**3.48**	4.28	**1.81**	0.98	0.71	1.19	1.49	1.53	1.27	0.97	1.15
Capital Investment	**3,128**	2,434	**1,025**	1,002	1,101	1,274	866	822	746	835	647
Free Funds Flow [3]	**3,613**	6,198	**2,422**	897	294	1,072	2,085	2,276	1,837	1,113	1,695
Excess Free Funds Flow [3]	**n/a**	n/a	**1,989**	505	(499)	786	1,756	2,020	2,615	1,169	1,626
Net Earnings (Loss) [4]	**3,366**	5,666	**1,864**	866	636	784	1,609	2,432	1,625	(408)	551
Per Share - Basic ($)	**1.76**	2.87	**0.98**	0.45	0.33	0.40	0.83	1.23	0.81	(0.21)	0.27
Per Share - Diluted ($)	**1.72**	2.79	**0.97**	0.44	0.32	0.39	0.81	1.19	0.79	(0.21)	0.27
Total Assets	**54,427**	55,086	**54,427**	53,747	54,000	55,869	55,086	55,894	55,655	54,104	54,594
Total Long-Term Liabilities	**18,395**	19,378	**18,395**	19,831	19,917	20,259	19,378	20,742	21,889	23,191	22,929
Long-Term Debt, Including Current Portion	**7,224**	8,774	**7,224**	8,534	8,681	8,691	8,774	11,228	11,744	12,385	12,986
Net Debt	**5,976**	5,280	**5,976**	6,367	6,632	4,282	5,280	7,535	8,407	9,591	11,024
Cash Returns to Shareholders	**2,067**	2,650	**1,225**	584	258	807	873	1,233	544	343	44
Common Shares – Base Dividends	**729**	481	**264**	265	200	201	205	207	69	70	35
Base Dividends Per Common Share ($)	**0.385**	0.245	**0.140**	0.140	0.105	0.105	0.105	0.105	0.035	0.035	0.018
Common Shares – Variable Dividends	**—**	—	**—**	—	—	219	—	—	—	—	—
Variable Dividends Per Common Share ($)	**—**	—	**—**	—	—	0.114	—	—	—	—	—
Purchase of Common Shares Under NCIB	**711**	2,143	**361**	310	40	387	659	1,018	466	265	—
Payment for Purchase of Warrants	**600**	—	**600**	—	—	—	—	—	—	—	—
Preferred Share Dividends	**27**	26	**—**	9	18	—	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) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(4) Net earnings (loss) for all periods in the table above is the same as net earnings (loss) from continuing operations.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results — Upstream

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2023	**Percent Change**	2022	**2023**	**Percent Change**	2022
Upstream Production Volumes by Segment [1] (MBOE/d)						
Oil Sands	**603.4**	**3**	587.1	**589.0**	**1**	580.9
Conventional [2]	**127.2**	**1**	126.2	**118.5**	**(7)**	128.0
Offshore	**66.4**	**3**	64.6	**61.2**	**(13)**	70.3
Total Production Volumes	**797.0**	**2**	777.9	**768.7**	**(1)**	779.2
Upstream Production Volumes by Product						
Bitumen (Mbbls/d)	**586.0**	**3**	568.2	**570.6**	**1**	562.4
Heavy Crude Oil (Mbbls/d)	**15.6**	**(7)**	16.8	**16.5**	**—**	16.5
Light Crude Oil (Mbbls/d)	**15.2**	**(5)**	16.0	**13.5**	**(32)**	19.8
NGLs (Mbbls/d)	**35.6**	**11**	32.1	**31.9**	**(10)**	35.4
Conventional Natural Gas (MMcf/d)	**867.4**	**—**	868.7	**818.1**	**(6)**	870.9
Total Production Volumes (MBOE/d)	**797.0**	**2**	777.9	**768.7**	**(1)**	779.2

(1) Refer to the Oil Sands, Conventional or Offshore Reportable Segments section of this MD&A for a summary of production by product type.
(2) All natural gas produced by the Conventional segment is internally consumed by the Oil Sands and Canadian Manufacturing segments.

Total upstream production increased 19.1 thousand BOE per day in the third quarter of 2023 compared with 2022 due to:

- The acquisition of the remaining 50 percent interest in the Sunrise Oil Sands Partnership ("Sunrise" or the "Sunrise Acquisition") from BP Canada Energy Group ULC ("bp Canada") on August 31, 2022, and successful results from the 2023 redevelopment program.
- The impact of well pads brought online at Foster Creek in the second and third quarters of 2023, combined with planned maintenance and an unplanned outage in 2022.
- First gas production at the MBH and MDA fields in Indonesia in the fourth quarter of 2022.
- First oil at the Spruce Lake North thermal plant late in the third quarter of 2022.

The increase was partially offset by lower production at Christina Lake due to flush production following a planned turnaround in the second quarter of 2022, and the timing of new well pads in 2023.

Production decreased 10.5 thousand BOE per day in the first nine months of 2023 compared with 2022 due to:

- The temporary shut-in of a significant portion of production in our Conventional operations in response to wildfire activity in the second quarter of 2023.
- Changes to the Liwan 3-1 gas sales agreement in China in the second quarter of 2022, concluding the amendment that temporarily increased sales volumes.
- A temporary unplanned outage in China in the second quarter of 2023, related to the disconnection of the umbilical cord by a third-party vessel in early April, reconnected in May.
- Lower production at Christina Lake as discussed above, partially offset by turnaround activity in the second quarter of 2022.
- Decreased production at Foster Creek due to a planned turnaround in the second quarter of 2023 having a greater impact than the 2022 planned maintenance and unplanned outage.

The decrease was partially offset by the same factors impacting the third quarter of 2023.

Selected Operating Results — Downstream

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2023	**Percent Change**	2022	**2023**	**Percent Change**	2022
Downstream Crude Oil Unit Throughput (Mbbls/d)						
Canadian Manufacturing	**108.4**	**10**	98.5	**100.8**	**9**	92.5
U.S. Manufacturing	**555.9**	**28**	435.0	**453.3**	**12**	405.3
Total Crude Oil Unit Throughput	**664.3**	**25**	533.5	**554.1**	**11**	497.8
Downstream Production Volumes [1] (Mbbls/d)						
Canadian Manufacturing	**122.4**	**10**	111.0	**114.6**	**10**	104.2
U.S. Manufacturing	**583.6**	**26**	461.6	**475.2**	**11**	426.7
Total Downstream Production	**706.0**	**23**	572.6	**589.8**	**11**	530.9

(1) Refer to the Canadian Manufacturing and U.S. Manufacturing Reportable Segments section of this MD&A for a summary of production by product type.

In the Canadian Manufacturing segment, total throughput and refined product production increased in the three months ended September 30, 2023, compared with 2022. The increases were due to the Lloydminster Upgrader ("Upgrader") and Lloydminster Refinery running at or near capacity in the third quarter of 2023, combined with temporary unplanned outages in the third quarter of 2022.

Crude throughput and refined product production increased in the nine months ended September 30, 2023, compared with 2022 due the same factors as discussed above, combined with:

- The Lloydminster Refinery running at or near capacity in the first nine months of 2023.
- Additional temporary unplanned outages and planned turnarounds in 2022 at the Upgrader and Lloydminster Refinery.

The increases were partially offset by an unplanned outage at the Upgrader in the second quarter of 2023.

In the U.S. Manufacturing segment, total throughput and refined product production increased significantly in the three months ended September 30, 2023, compared with 2022 due to:

- The purchase of the remaining 50 percent interest in the Toledo Refinery from BP Products North America Inc. ("bp") on February 28, 2023 (the "Toledo Acquisition"). The refinery partially restarted in April and commenced full operations in June. Crude utilization in the third quarter of 2023 was 90 percent (2022 – 58 percent).
- The introduction of crude oil at the Superior Refinery in mid-March 2023. We safely restarted the FCCU in early October. Crude utilization in the third quarter of 2023 was 66 percent (2022 – nil).
- Strong performance from the Wood River Refinery, combined with the impact of the planned turnaround in the third quarter of 2022. Crude utilization at the Wood River and Borger refineries in the third quarter was 95 percent (2022 – 91 percent).

The increases were partially offset by unplanned outages combined with planned maintenance at the Lima Refinery. In the third quarter, crude utilization at the Lima Refinery was 82 percent (2022 – 94 percent). We continue to find ways to integrate the Lima and Toledo refineries to optimize our operating margin.

Crude throughput and refined product production increased in the nine months ended September 30, 2023, compared with 2022 due the same factors as discussed above, combined with:

- Relatively consistent year-to-date performance at the Lima Refinery. Crude utilization was 89 percent (2022 – 88 percent).
- The planned turnaround completed at the Wood River Refinery in the second quarter of 2023 having less of an impact than the turnaround in 2022 and the decision to operate at reduced rates early in 2022 to optimize margins as market conditions dictated.

The increase was partially offset by:

- A planned turnaround at the Borger Refinery in the spring and temporary unplanned outages in the second quarter. The turnaround and outages had a larger impact on throughput than the turnaround completed in the spring of 2022.
- Unplanned outages at the Wood River and Borger refineries in the fourth quarter of 2022 that were resolved in the first quarter of 2023.

Selected Consolidated Financial Results

Revenues

Revenues decreased 17 percent to $14.6 billion from the third quarter of 2022. Year-to-date, revenues decreased 26 percent to $39.1 billion from 2022. The decreases were primarily due to lower blended crude oil benchmark pricing impacting our Oil Sands segment, and lower natural gas and refined product benchmark pricing, partially offset by a weaker Canadian dollar on average relative to the U.S. dollar.

Operating Margin

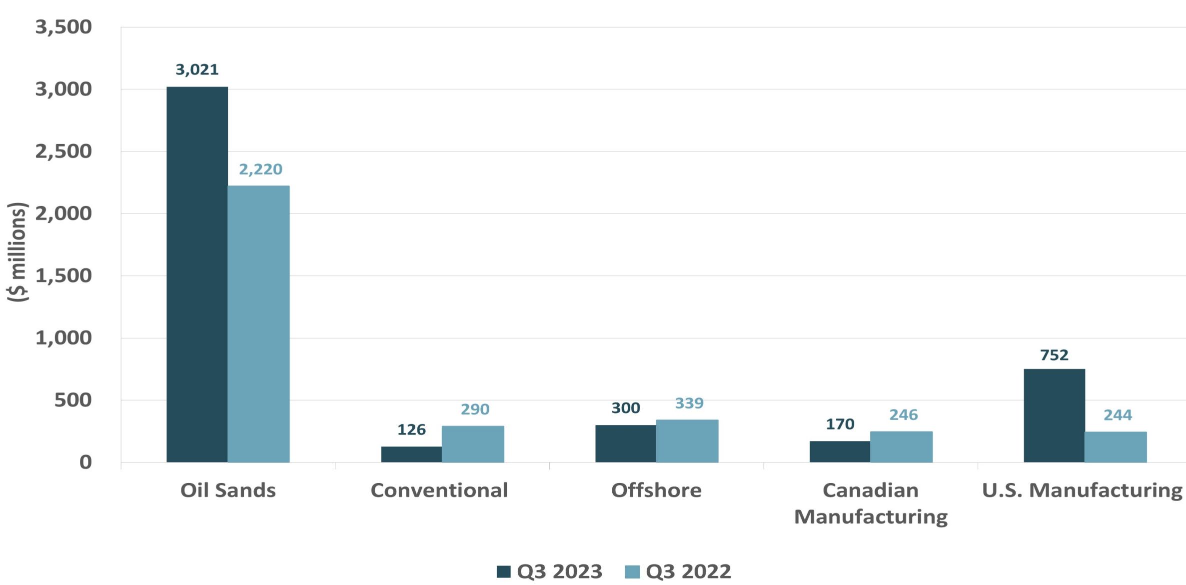
Operating Margin is a specified financial measure and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2023**	2022	**2023**	2022
Gross Sales [1]	**18,441**	21,123	**47,507**	62,599
Less: Royalties	**1,135**	1,226	**2,368**	3,993
Revenues	**17,306**	19,897	**45,139**	58,606
Expenses				
Purchased Product [1]	**8,847**	12,063	**22,874**	31,078
Transportation and Blending [1]	**2,397**	2,826	**8,194**	9,317
Operating Expenses	**1,692**	1,695	**5,201**	5,125
Realized (Gain) Loss on Risk Management Activities	**1**	(26)	**(1)**	1,605
Operating Margin	**4,369**	3,339	**8,871**	11,481

(1) *Comparative periods reflect certain revisions. See Note 26 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.*

Operating Margin by Segment

Three Months Ended September 30, 2023 and 2022

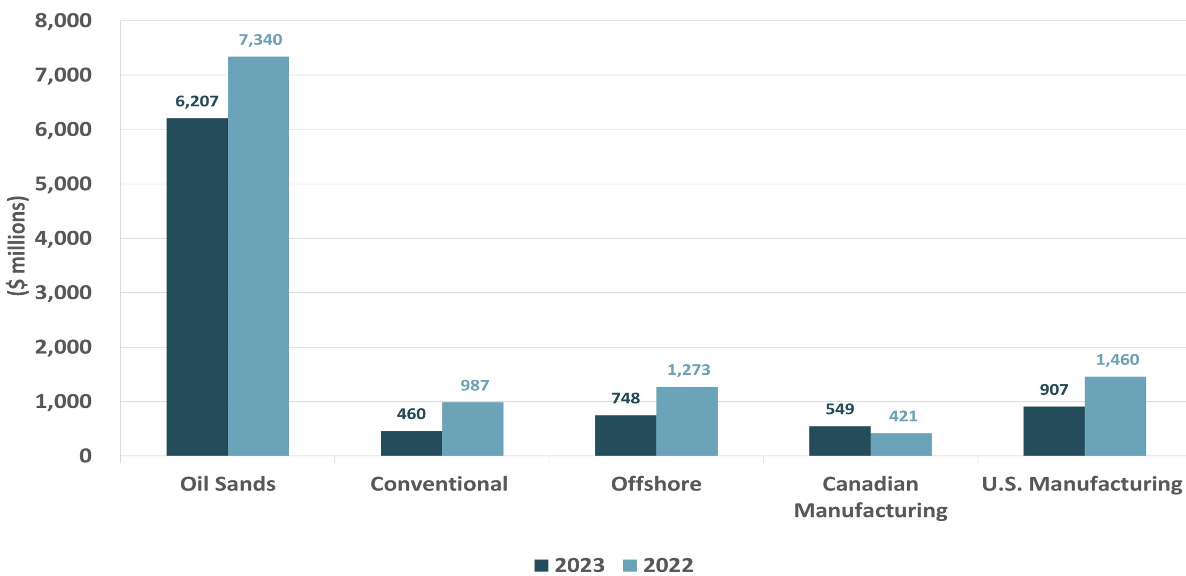


Operating Margin increased $1.0 billion to $4.4 billion in the three months ended September 30, 2023, compared with the same period in 2022, primarily due to:

- Higher gross margins in the U.S. Manufacturing segment mainly resulting from the Toledo Refinery being fully operational and the Superior Refinery ramping up operations in the third quarter of 2023, combined with processing feedstock purchased at lower prices in the second quarter positively impacting our U.S. refining margins in the third quarter.
- Increased realized crude oil sales prices from the Oil Sands segment due to a higher percentage of recovered condensate costs through blended sales due to a significantly narrower WCS-Condensate differential. In addition, our Oil Sands segment benefited from blending condensate purchased at lower prices.
- Higher Oil Sands sales volumes mainly driven by higher production.

Operating Margin in the Conventional segment decreased compared with 2022 primarily due to lower realized natural gas prices. The decrease was generally offset by reduced fuel operating costs in the Oil Sands and Canadian Manufacturing segments on natural gas purchased from the Conventional segment.

Nine Months Ended September 30, 2023 and 2022



Operating Margin decreased $2.6 billion to $8.9 billion in the nine months ended September 30, 2023, compared with the same period in 2022, primarily due to:

- Lower realized crude oil and NGLs sales prices resulting from lower benchmark pricing.
- Decreased gross margin from the U.S. Manufacturing segment resulting from lower market crack spreads, partially offset by higher throughput and refined product production with Toledo and Superior refineries being operational.
- Lower sales volumes from our Offshore segment.
- Increased non-fuel operating expenses from the Oil Sands segment primarily due to higher repairs and maintenance costs.
- Higher transportation costs from the Oil Sands segment mainly due to increased tariff rates.

These decreases in Operating Margin were partially offset by:

- Lower royalties in the Oil Sands and Conventional segments, resulting from lower crude oil and natural gas benchmark pricing.
- Minor realized risk management gains in 2023 compared with significant realized risk management losses in 2022.

Operating Margin in the Conventional segment decreased compared with 2022 primarily due to lower realized natural gas prices. The decrease was generally offset by reduced fuel operating costs in the Oil Sands and Canadian Manufacturing segments on natural gas purchased from the Conventional segment.

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2023**	2022	**2023**	2022
Cash From (Used in) Operating Activities	**2,738**	4,089	**4,442**	8,433
(Add) Deduct:				
Settlement of Decommissioning Liabilities	**(68)**	(55)	**(157)**	(101)
Net Change in Non-Cash Working Capital	**(641)**	1,193	**(2,142)**	(98)
Adjusted Funds Flow	**3,447**	2,951	**6,741**	8,632

Cash from operating activities decreased in the third quarter of 2023 compared with 2022. Higher Operating Margin was more than offset by changes in non-cash working capital. The net change in non-cash working capital of $641 million was mainly due to an increase in accounts receivable, inventories and higher cash taxes, primarily due to rising commodity prices. The change was partially offset by higher accounts payable primarily due to increased crude throughput.

Adjusted Funds Flow was higher in the third quarter of 2023 compared with 2022, primarily due to increased Operating Margin.

Cash from operating activities decreased in the first nine months of 2023 compared with 2022. The decline was primarily due to lower Operating Margin and changes in non-cash working capital, partially offset by the 2022 contingent payment. The net change in non-cash working capital in the first nine months of 2023 was $2.1 billion, mainly due to paying a $1.2 billion income tax liability and the same factors impacting the third quarter discussed above.

Adjusted Funds Flow was lower in the nine months ended September 30, 2023 compared with 2022, primarily due to decreased Operating Margin.

Net Earnings (Loss)

($ millions)	Three Months Ended	Nine Months Ended
Net Earnings (Loss), for the Periods Ended September 30, 2022	**1,609**	**5,666**
Increase (Decrease) due to:		
Operating Margin	**1,030**	**(2,610)**
Corporate and Eliminations:		
General and Administrative	**(164)**	**(72)**
Finance Costs	**101**	**138**
Integration and Transaction Costs	**15**	**30**
Unrealized Foreign Exchange Gain (Loss)	**239**	**518**
Revaluation Gain (Loss)	**(549)**	**(582)**
Re-measurement of Contingent Payments	**(176)**	**59**
Gain (Loss) on Divestiture of Assets	**60**	**(233)**
Other Income (Loss), net	**(37)**	**(425)**
Other (1)	**(214)**	**(284)**
Unrealized Risk Management Gain (Loss)	**(54)**	**(91)**
Depreciation, Depletion and Amortization	**(150)**	**(165)**
Exploration Expense	**71**	**89**
Income Tax (Expense) Recovery	**83**	**1,328**
Net Earnings (Loss), for the Periods Ended September 30, 2023	**1,864**	**3,366**

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

Net earnings in the third quarter of 2023 increased by $255 million compared with the same period in 2022 due to higher Operating Margin, lower unrealized foreign exchange losses and decreased finance costs. The increase was partially offset by the revaluation gain related to the Sunrise Acquisition in the third quarter of 2022, a loss on re-measurement of the Sunrise contingent payment compared with a gain in 2022, higher general and administrative expenses due to long-term incentive costs, and increased DD&A.

Net earnings in the first nine months of 2023 decreased by $2.3 billion compared with the same period in 2022 due to declines in Operating Margin, the revaluation gain related to the Sunrise Acquisition in 2022, lower other income due to the 2022 insurance proceeds related to the Superior Refinery and Atlantic region incidents, higher net gains on asset divestitures in 2022 and higher DD&A. The decrease in net earnings was partially offset by a lower income tax expense, unrealized foreign exchange gains in 2023 compared with losses in 2022, and decreased finance costs.

Net Debt

As at ($ millions)	September 30, 2023	June 30, 2023	December 31, 2022
Short-Term Borrowings	**14**	—	115
Current Portion of Long-Term Debt	**—**	—	—
Long-Term Portion of Long-Term Debt	**7,224**	8,534	8,691
Total Debt	**7,238**	8,534	8,806
Less: Cash and Cash Equivalents	**(1,262)**	(2,167)	(4,524)
Net Debt	**5,976**	6,367	4,282

Long-term debt decreased by $1.3 billion from June 30, 2023, and $1.5 billion from December 31, 2022, primarily due to the purchase of unsecured notes with an aggregate principal amount of US$1.0 billion in the third quarter of 2023. Net Debt decreased by $391 million from June 30, 2023 and increased by $1.7 billion from December 31, 2022. The year-to-date increase is partly due to the payment of a $1.2 billion income tax liability in the first quarter of 2023.

For further details see the Liquidity and Capital Resources section of this MD&A.

Capital Investment (1)

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2023**	2022	**2023**	2022
Upstream				
Oil Sands	**590**	360	**1,764**	1,111
Conventional	**100**	67	**323**	188
Offshore	**194**	81	**478**	225
Total Upstream	**884**	508	**2,565**	1,524
Downstream				
Canadian Manufacturing	**38**	24	**99**	77
U.S. Manufacturing	**88**	300	**435**	774
Total Downstream	**126**	324	**534**	851
Corporate and Eliminations	**15**	34	**29**	59
Total Capital Investment	**1,025**	866	**3,128**	2,434

(1) Includes expenditures on property, plant and equipment ("PP&E"), exploration and evaluation ("E&E") assets, and capitalized interest. Excludes cost incurred in our equity-accounted investment in Indonesia.

Oil Sands capital investment in the first nine months of 2023 was mainly for sustaining activities and the drilling of stratigraphic test wells as part of our integrated winter program in the first quarter, in addition to optimization and growth investment.

Conventional capital investment in the nine months of 2023 continued to focus on drilling, completion, tie-in and infrastructure projects.

Offshore capital investment in the first nine months of 2023 was primarily for the West White Rose project and Terra Nova asset life extension ("ALE") project in the Atlantic region.

U.S. Manufacturing capital investment in the first nine months of 2023 focused primarily on the Superior Refinery rebuild, and growth and reliability initiatives at the Wood River, Borger, Lima and Toledo refineries.

Drilling Activity

Nine Months Ended September 30,	Net Stratigraphic Test Wells and Observation Wells 2023	2022	Net Production Wells [1] 2023	2022
Foster Creek	**87**	52	**34**	22
Christina Lake	**53**	—	**11**	21
Sunrise	**38**	15	**15**	2
Lloydminster Thermal	**8**	1	**2**	29
Lloydminster Conventional Heavy Oil	**1**	—	**21**	—
Other [2]	**3**	22	**—**	—
	190	90	**83**	74

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

Stratigraphic test wells were drilled to help identify future well pad locations 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, 2023			Nine Months Ended September 30, 2022		
(net wells)	**Drilled**	**Completed**	**Tied-in**	Drilled	Completed	Tied-in
Conventional	**30**	**29**	**30**	19	28	29

In the Offshore segment, we drilled and completed one (0.4 net) planned development well at the MAC field in Indonesia in the first nine months of 2023 (first nine months of 2022 – drilled and completed seven (2.8 net) planned development wells at the MBH and MDA fields in Indonesia).

Future Capital Investment

Future Capital Investment is a specified financial measure. See the Specified Financial Measures Advisory of this MD&A. Our 2023 guidance, as updated on July 26, 2023, is available on our website at cenovus.com.

The following table shows guidance for 2023:

	Capital Investment ($ millions)	Production (MBOE/d)	Crude Oil Unit Throughput (Mbbls/d)
Upstream			
Oil Sands	**2,200 - 2,400**	**577 - 637**	
Conventional	**350 - 450**	**115 - 130**	
Offshore	**600 - 700**	**55 - 68**	
Downstream	**800 - 900**		**580 - 610**
Corporate and Eliminations	**40 - 50**		

2023 guidance for total capital investment is between $4.0 billion and $4.5 billion. This includes sustaining capital of approximately $2.8 billion, and between $1.2 billion and $1.7 billion in optimization and growth capital.

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, refined product prices and 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]

	Nine Months Ended September 30,					
(Average US$/bbl, unless otherwise indicated)	**2023**	**Percent Change**	2022	**Q3 2023**	Q2 2023	Q3 2022
Dated Brent	**82.14**	**(22)**	105.35	**86.76**	78.39	100.85
WTI	**77.39**	**(21)**	98.09	**82.26**	73.78	91.55
Differential Dated Brent-WTI	**4.75**	**(35)**	7.26	**4.50**	4.61	9.30
WCS at Hardisty	**59.82**	**(27)**	82.36	**69.35**	58.74	71.69
Differential WTI-WCS	**17.57**	**12**	15.73	**12.91**	15.04	19.86
WCS (C$/bbl)	**80.47**	**(24)**	105.54	**93.06**	78.90	93.53
WCS at Nederland	**69.12**	**(25)**	91.81	**77.89**	66.98	82.91
Differential WTI-WCS at Nederland	**8.27**	**32**	6.28	**4.37**	6.80	8.64
Condensate (C5 @ Edmonton)	**76.74**	**(21)**	97.24	**77.96**	72.39	87.26
Differential WTI-Condensate (Premium)/Discount	**0.65**	**24**	0.85	**4.30**	1.39	4.29
Differential WCS [2]-Condensate (Premium)/Discount	**(16.92)**	**(14)**	(14.88)	**(8.61)**	(13.65)	(15.57)
Condensate (C$/bbl)	**103.28**	**(17)**	124.62	**104.63**	97.25	113.89
Synthetic @ Edmonton	**79.93**	**(22)**	102.61	**84.95**	76.66	100.34
Differential WTI-Synthetic (Premium)/Discount	**(2.54)**	**44**	(4.52)	**(2.69)**	(2.88)	(8.79)
Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**102.58**	**(19)**	126.58	**105.59**	102.32	121.52
Chicago Ultra-low Sulphur Diesel ("ULSD")	**110.52**	**(24)**	144.82	**113.77**	102.40	148.24
Refining Benchmarks						
Chicago 3-2-1 Crack Spread [3]	**27.83**	**(19)**	34.57	**26.06**	28.57	38.87
Group 3 3-2-1 Crack Spread [3]	**33.36**	**(3)**	34.29	**36.96**	31.78	38.57
Renewable Identification Numbers ("RINs")	**7.80**	**5**	7.45	**7.42**	7.72	8.11
Natural Gas Prices						
AECO [4] (C$/Mcf)	**2.76**	**(49)**	5.38	**2.60**	2.45	4.16
NYMEX [5] (US$/Mcf)	**2.69**	**(60)**	6.77	**2.55**	2.10	8.20
Foreign Exchange Rates						
US$ per C$1 - Average	**0.743**	**(5)**	0.780	**0.746**	0.745	0.766
US$ per C$1 - End of Period	**0.740**	**1**	0.730	**0.740**	0.755	0.730
RMB per C$1 - Average	**5.229**	**2**	5.147	**5.402**	5.228	5.246

(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) WCS at Hardisty.
(3) The average 3-2-1 crack spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.
(4) Alberta Energy Company ("AECO") 5A natural gas daily index.
(5) NYMEX natural gas monthly index.

Crude Oil and Condensate Benchmarks

In the third quarter of 2023, Brent and WTI prices improved from the second quarter of 2023 mainly due to seasonal demand strength and announcements that Saudi Arabia and Russia will extend voluntary production cuts through the end of 2023. Benchmark prices in the three and nine months ending September 30, 2023, were lower than the same periods in 2022, as the global crude supply deficit put significant upward pressure on prices in 2022, which was exacerbated by risks related to Russian export supply shortfall uncertainty. Global supply growth and resilient Russian exports have resulted in a more balanced crude market in 2023, resulting in prices falling from elevated levels last year.

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 narrowed in the third quarter of 2023 and on a year-to-date basis compared with 2022 as physical supply uncertainty and high marine fuel prices caused the differential to widen significantly in 2022 in the months following Russia's invasion of Ukraine in February 2022. The Brent-WTI differential was relatively consistent between the second and third quarters of 2023.

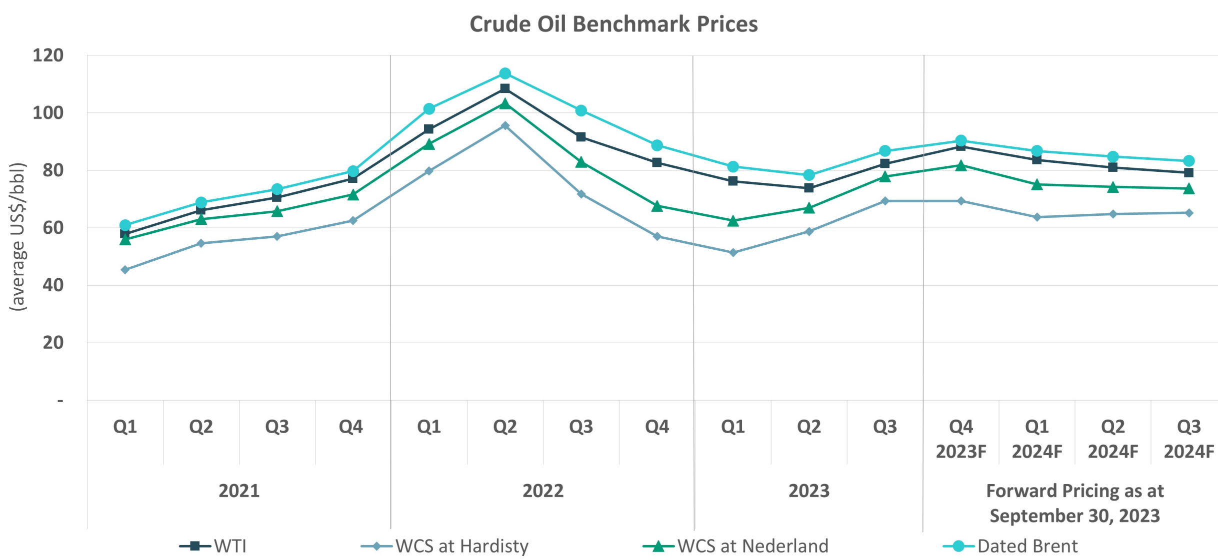
WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WCS at Hardisty differential to WTI is a function of the quality differential of light and heavy crude and the cost of transport. The average WTI-WCS differential at Hardisty narrowed from the second quarter of 2023 due to voluntary OPEC+ cuts to medium and heavy crude production. The differential also narrowed compared with the third quarter of 2022, as 2022 saw slightly higher transport costs from increased pipeline utilization and a wider quality differential attributed to high global refining utilization, rising supply of medium and heavy oil barrels into the market from OPEC+, and releases of U.S. government Strategic Petroleum Reserves ("SPRs").

During the nine months ended September 30, 2023, the WTI-WCS differential at Hardisty widened compared with 2022 primarily as a result of high heavy crude processing utilization in the USGC, planned and unplanned refinery maintenance and volatile refined product pricing.

WCS at Nederland is a heavy oil benchmark for sales of our product at the USGC. The WTI-WCS at Nederland differential is representative of the heavy oil quality discount and is influenced by global heavy oil refining capacity and global heavy oil supply. The WTI-WCS at Nederland differential narrowed from the second quarter of 2023 and the third quarter of 2022, and widened in the nine months ended September 30, 2023, compared with 2022, due to the same factors impacting the WTI-WCS differential at Hardisty discussed above.

In Canada, we upgrade heavy crude oil and bitumen into a sweet synthetic crude oil, the Husky Synthetic Blend ("HSB"), at the 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.

In the three and nine months ended September 30, 2023, synthetic crude at Edmonton was at a lower premium to WTI compared with the same periods in 2022. Synthetic crude prices were elevated in the second and third quarters of 2022 as a result of upgrader maintenance in Western Canada and strong refinery demand for light crude oil. The premium in the third quarter of 2023 narrowed slightly compared with the second quarter.



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. The WCS-Condensate differential narrowed in the third quarter of 2023 from the second quarter due to relative strengthening of WCS discussed above.

In the three and nine months ended September 30, 2023, the Edmonton condensate discount to WTI was consistent with the same periods in 2022. The discount widened from the second quarter of 2023, consistent with seasonal pricing patterns and lower heavy crude blending requirements in summer months.

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.

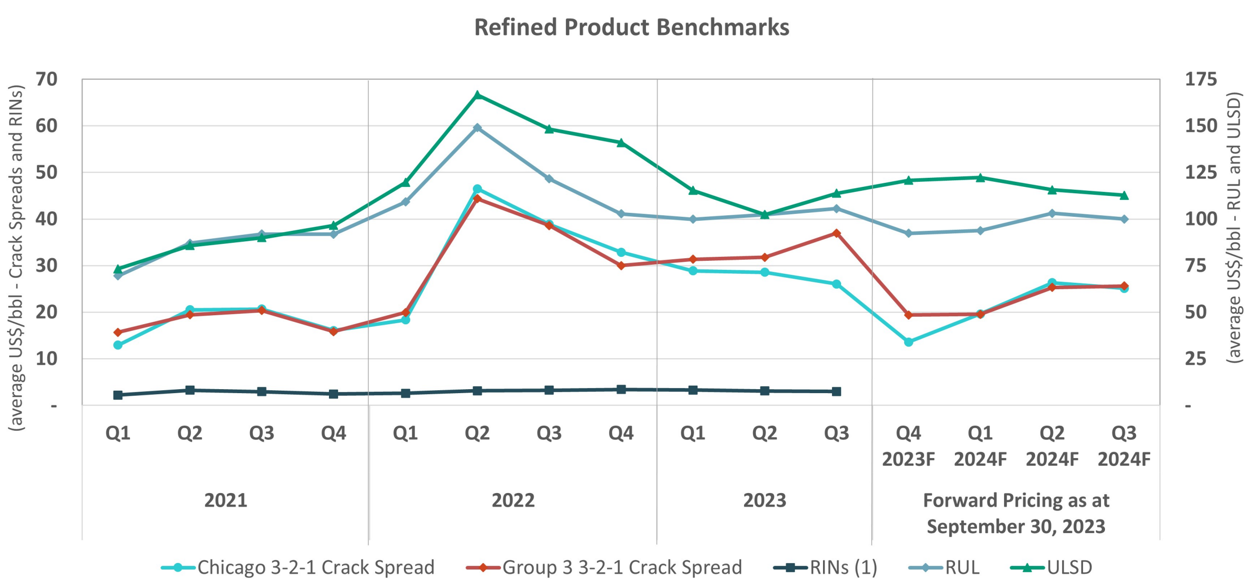
The Chicago 3-2-1 market crack spread reflects the market for the Toledo, Lima and Wood River refineries. The Group 3 3-2-1 market crack spread reflects the market for the Superior and Borger refineries.

Refined product prices declined in the three and nine months ended September 30, 2023, compared with the same periods in 2022. Market crack spreads also declined during this period as 2022 saw periods of historically high refined product prices and refining margins.

Reduced refinery outages and incremental global capacity additions have resulted in declining refined product prices relative to WTI in 2023, compared with 2022, particularly in diesel markets. The Chicago 3-2-1 market crack spread declined compared with the second quarter of 2023 as regional refining utilization was high and waterway maintenance prevented products from being barged to other markets. Group 3 3-2-1 crack spreads increased from the second quarter of 2023 due to higher diesel pricing amid strong demand and low diesel imports as a result of low global inventories. RINs costs remain high as a result of a tight biofuel market, high feedstock prices and uncertainty around policies that drive RINs demand.

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 generally reflects the differential between Brent and WTI benchmark prices.

Our refining margins are affected by many other factors such as the variety of crude oil feedstock, refinery configuration and product output, where feedstocks are acquired and 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 and AECO natural gas prices decreased significantly compared with the three and nine months ended September 30, 2022, due to mild winter conditions weighing on U.S. domestic demand coupled with record high natural gas production and inventories. NYMEX natural gas prices increased marginally compared with the second quarter of 2023 as record high summer natural gas consumption in the U.S. outweighed high production levels. AECO natural gas prices increased slightly compared with the second quarter of 2023 as higher Western Canadian exports and seasonal pipeline maintenance resulted in a widening differential to NYMEX that offset the increase in NYMEX prices. The price received for our Asia Pacific natural gas production is largely based on long-term contracts.

Foreign Exchange Benchmarks

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. dollar 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 our U.S. and Asia Pacific operations.

In the three and nine months ended September 30, 2023, the Canadian dollar on average weakened relative to the U.S. dollar compared with the same periods in 2022, positively impacting our reported revenues. The Canadian dollar weakened relative to the U.S. dollar as at September 30, 2023, compared with June 30, 2023, resulting in unrealized foreign exchange losses in the third quarter on the translation of our U.S. dollar debt into Canadian dollars. The Canadian dollar was consistent relative to the U.S. dollar as at September 30, 2023, compared with December 31, 2022, resulting in minimal unrealized foreign exchange impacts.

A portion of our long-term sales contracts in the Asia Pacific region 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 three and nine months ended September 30, 2023, the Canadian dollar on average was relatively consistent with RMB compared with the same periods in 2022, resulting in minimal impact on our revenues.

Interest Rate Benchmarks

Our interest income, short-term borrowing costs, reported decommissioning liabilities and fair value measurements are impacted by fluctuations in interest rates. A change in interest rates could change our net interest expense and affect how certain liabilities are measured and impact our cash flow and financial results.

As at September 30, 2023, the Bank of Canada’s Policy Interest Rate was 5.00 percent, an increase from 4.75 percent on June 30, 2023, and from 4.25 percent on December 31, 2022, due to concerns over inflation. On October 25, 2023, the Bank of Canada announced the rate will remain at 5.00 percent.

OUTLOOK

COMMODITY PRICE OUTLOOK

Global crude oil prices increased quarter-over-quarter for the first time since the second quarter of 2022 largely due to production cuts by Saudi Arabia and Russia. Crude oil demand growth has been resilient in 2023 despite weak macroeconomic indicators, supported by the lifting of China’s COVID-19 restrictions earlier in the year.

Crude oil price trajectory remains uncertain and volatile amid a market with unpredictable key drivers and government policy playing a large role in supply and demand dynamics. Policies regarding Russia, Iran and Venezuela are among key factors that will drive energy supply and shift global trade patterns. The OPEC+ announced extension of production cuts that will continue to be supportive of pricing, with production quotas being a key driver of crude oil prices. Overall, we expect the general outlook for crude oil and refined product prices will be volatile and impacted by OPEC+ policy, the duration and severity of the ongoing Russian invasion of Ukraine, the extent to which Russian exports are reduced by sanctions or production cuts, the pace of non-OPEC+ supply growth, the refilling of SPRs, and the crisis in Israel and Gaza. In addition, weakening global 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 the WTI-WCS at Hardisty differential will remain largely tied to global supply factors and heavy crude oil processing capacity as long as supply stays within Canadian crude oil export capacity. We expect the start-up of the Trans Mountain pipeline expansion in 2024 to have a narrowing impact on WTI-WCS differentials.
- We expect refined product prices and market crack spreads will remain volatile. Economic effects of the ongoing Russian invasion of Ukraine and central bank policies could impact demand. Refined product prices and market crack spreads are likely to continue to fluctuate, adjusting for seasonal trends and refinery utilization in North America.
- NYMEX and AECO natural gas prices are expected to remain under pressure in the near-term due to strong supply and ample natural gas in storage. Weather will continue to be a key driver of demand and impact prices.
- 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 and downstream refined product production are exposed to movements in the WTI crude oil price. Our physically integrated upstream and downstream operations help us to mitigate the impact of commodity price volatility. Natural gas and NGLs production associated with our Conventional operations provide economic integration for the fuel and blending requirements at our Oil Sands and Canadian Manufacturing operations. Crude oil production in our upstream assets is blended with condensate and used as feedstock by our downstream operations, and condensate extracted from our blended crude oil is sold back to our Oil Sands operations. The restart of the Superior and Toledo refineries provide further integration.

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 spreads in all of these markets. We will continue to monitor market fundamentals and optimize run rates at our refineries accordingly.

Our 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 the majority of our 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.

REPORTABLE SEGMENTS

UPSTREAM

Oil Sands

In the third quarter of 2023, we:

- Delivered safe and reliable operations.
- Produced 601.6 thousand barrels of crude oil per day (2022 – 585.0 thousand barrels of crude oil per day).
- Brought two new well pads on production at Foster Creek.
- Completed the ramp up of one well pad at Foster Creek and two wells pads at Christina Lake that started up in the second quarter.
- Acquired the remaining 10 percent interest in the Ipiatik area at Foster Creek, which will provide additional bitumen reserves to the Foster Creek plant.
- Completed a planned turnaround at Christina Lake with minimal production impacts.
- Generated Operating Margin of $3.0 billion, an increase of $801 million compared with 2022 primarily due to higher average realized sales prices, and higher sales volumes driven by higher production.
- Invested capital of $590 million primarily for sustaining activities.
- Achieved a Netback of $54.78 per BOE (2022 – $41.91 per BOE).

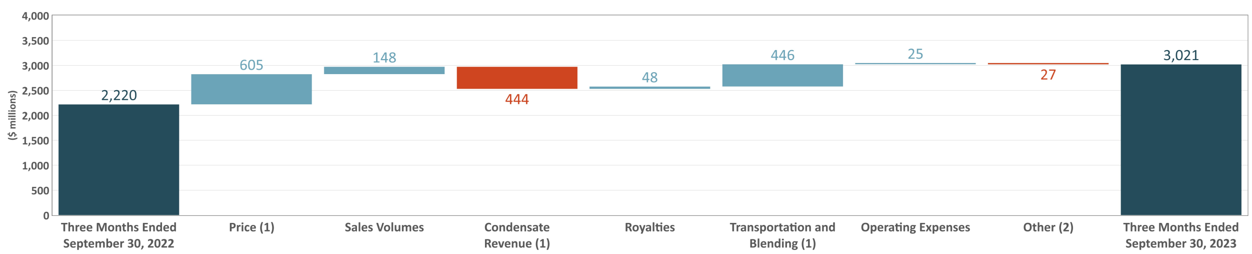
Financial Results

($ millions)	Three Months Ended September 30, 2023	2022	Nine Months Ended September 30, 2023	2022
Revenues				
Gross Sales [1]	**7,571**	8,764	**19,715**	28,030
Less: Royalties	**1,082**	1,136	**2,218**	3,709
	6,489	7,628	**17,497**	24,321
Expenses				
Purchased Product [1]	**462**	1,919	**1,231**	4,202
Transportation and Blending	**2,324**	2,758	**7,965**	9,114
Operating	**688**	689	**2,101**	2,197
Realized (Gain) Loss on Risk Management	**(6)**	42	**(7)**	1,468
Operating Margin	**3,021**	2,220	**6,207**	7,340
Unrealized (Gain) Loss on Risk Management	**47**	(2)	**44**	(59)
Depreciation, Depletion and Amortization	**785**	652	**2,230**	1,977
Exploration Expense	**—**	7	**4**	7
(Income) Loss from Equity-Accounted Affiliates	**—**	—	**6**	8
Segment Income (Loss)	**2,189**	1,563	**3,923**	5,407

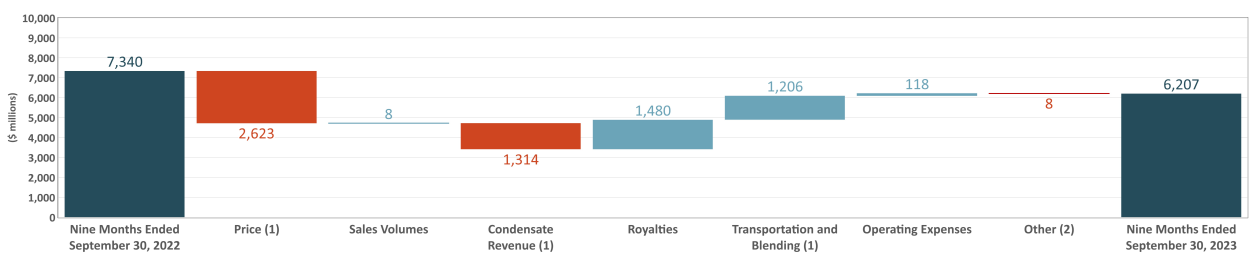
(1) Comparative periods reflect certain revisions. See Note 26 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Operating Margin Variance

Three Months Ended September 30, 2023



Nine Months Ended September 30, 2023



(1) Reported revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expenses. The crude oil price excludes the impact of condensate purchases. Changes to price include the impact of realized risk management gains and losses.
(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,	
	2023	2022	**2023**	2022
Total Sales Volumes [1] (MBOE/d)	**597.2**	578.0	**584.1**	583.8
Total Realized Price [2] ($/BOE)	**94.45**	84.29	**74.08**	99.78
Crude Oil Production by Asset (Mbbls/d)				
Foster Creek	**189.3**	182.4	**182.1**	189.3
Christina Lake	**237.6**	252.8	**236.6**	245.2
Sunrise [3]	**54.5**	30.9	**48.6**	26.8
Lloydminster Thermal	**104.6**	102.1	**103.3**	99.0
Lloydminster Conventional Heavy Oil	**15.6**	16.8	**16.5**	16.5
Tucker [4]	**—**	—	**—**	2.1
Total Crude Oil Production [5] (Mbbls/d)	**601.6**	585.0	**587.1**	578.9
Natural Gas [6] (MMcf/d)	**10.6**	12.6	**12.0**	12.5
Total Production (MBOE/d)	**603.4**	587.1	**589.0**	580.9
Effective Royalty Rate [7] (percent)				
Foster Creek	**23.4**	33.6	**22.9**	30.0
Christina Lake	**33.2**	34.8	**29.8**	31.8
Sunrise	**5.6**	9.6	**5.4**	7.3
Lloydminster [8]	**8.5**	9.7	**8.7**	10.0
Total Effective Royalty Rate	**22.6**	27.8	**21.1**	25.4
Transportation and Blending Expense [2] ($/BOE)	**7.41**	7.72	**8.16**	7.48
Operating Expense [2] ($/BOE)	**12.56**	13.40	**13.09**	13.83
Per Unit DD&A [2] ($/BOE)	**12.96**	11.63	**12.90**	11.83

(1) Bitumen, heavy crude oil and natural gas.
(2) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(3) On August 31, 2022, we acquired the remaining 50 percent interest in Sunrise from bp Canada.
(4) The Tucker asset was sold on January 31, 2022.
(5) Oil Sands production is primarily bitumen, except for Lloydminster conventional heavy oil, which is heavy crude oil.
(6) Conventional natural gas product type.
(7) Effective royalty rates are equal to royalty expense divided by product revenue, net of transportation expenses.
(8) Composed of Lloydminster thermal and Lloydminster conventional heavy oil assets.

Revenues

Price

Our heavy oil and bitumen production must be blended with condensate to reduce its viscosity in order to transport it to market through pipelines. Within our netback calculations, our realized bitumen and heavy oil sales price excludes the impact of purchased condensate; however, it is influenced by the price of condensate. As the cost of condensate used for blending increases relative to the price of blended crude oil or our blend ratio increases, our realized heavy oil and bitumen sales price decreases.

In the three and nine months ended September 30, 2023, condensate benchmark pricing was at a US$8.61 per barrel and US$16.92 per barrel premium to WCS at Hardisty, respectively (2022 – US$15.57 and US$14.88 per barrel premium, respectively). The significant quarter-over-quarter narrowing of WCS-condensate differentials had a positive impact on our realized bitumen sales price compared with 2022. Year-to-date, the widening of WCS-condensate differentials had a negative impact on our realized bitumen sales price compared with 2022. Up to three months may lapse from when we purchase condensate to when we sell our blended production.

Our realized sales price averaged $94.45 per BOE in the third quarter of 2023 (2022 – $84.29 per BOE) due to a lower cost of condensate, purchased earlier in the quarter, and a higher recovery of that cost through blended sales, with significantly narrower WCS-Condensate differentials. WTI benchmark pricing averaged US$82.26 per barrel in the third quarter of 2023 (2022 – US$91.55 per barrel). The decrease in WTI was mostly offset by narrower WTI-WCS differentials quarter-over-quarter. The WTI-WCS at Hardisty differential was US$12.91 per barrel in the three months ended September 30, 2023 (2022 – US$19.86 per barrel).

Our realized sales price decreased to $74.08 per BOE in the nine months ended September 30, 2023 from $99.78 per BOE in 2022 due to lower WTI benchmark prices and wider WTI-WCS differentials. In the nine months ended September 30, 2023, WTI averaged US$77.39 per barrel (2022 – US$98.09 per barrel) and the WTI-WCS at Hardisty differential was US$17.57 per barrel (2022 – US$15.73 per barrel).

For the three and nine months ended September 30, 2023, gross sales included $398 million and $1.0 billion, respectively (2022 – $1.9 billion and $4.0 billion, respectively), from third-party sourced volumes.

For the three and nine months ended September 30, 2023, gross sales included $95 million and $281 million, respectively (2022 – $79 million and $248 million, respectively), relating to construction, transportation and blending activities.

Cenovus makes storage and transportation decisions about utilizing our marketing and transportation infrastructure, including storage and pipeline assets, to optimize product mix, delivery points, transportation commitments and customer diversification. To price protect our inventories associated with storage or transport decisions, Cenovus may employ various price alignment and volatility management strategies, including risk management contracts, to reduce volatility in future cash flows and improve cash flow stability.

Realized (Gain) Loss on Risk Management

In the three and nine months ended September 30, 2023, our realized risk management gains were $6 million and $7 million, respectively (2022 – losses of $42 million and $1.5 billion, respectively). The changes from 2022 are due to management's decision to liquidate our WTI positions related to crude oil sales price risk management in the second quarter of 2022.

Production Volumes

Oil Sands crude oil production was 601.6 thousand barrels per day and 587.1 thousand barrels per day in the three and nine months ended September 30, 2023, respectively (2022 – 585.0 thousand barrels per day and 578.9 thousand barrels per day, respectively).

In the first nine months of 2023, we sold approximately 25 percent (2022 – 20 percent) of our crude oil volumes to third parties at U.S. destinations and sold approximately 20 percent of our crude oil volumes to our downstream operations.

Production at Foster Creek increased 6.9 thousand barrels per day in the third quarter of 2023 compared with 2022, primarily due to planned maintenance and an unplanned outage in the third quarter of 2022. In addition, we completed ramp up of one new well pad brought online in the second quarter of 2023 and brought two new well pads online in the third quarter of 2023. Year-to-date, production decreased 7.2 thousand barrels per day compared with 2022, primarily due to a planned turnaround that commenced in mid-April and completed in early May 2023, having a greater impact than the 2022 planned maintenance and unplanned outage.

Production at Christina Lake decreased 15.2 thousand barrels per day and 8.6 thousand barrels per day, respectively, in the three and nine months ended September 30, 2023 compared with the same periods in 2022. The decreases were primarily due to flush production following a planned turnaround in the second quarter of 2022 and the timing of new well pads in 2023 compared with the incremental production from development wells drilled in prior years. We brought two new well pads on production in the second quarter of 2023 which partially offset the decreases. We completed a planned turnaround in the third quarter of 2023 that had minimal production impacts.

The Sunrise Acquisition was completed on August 31, 2022. Production at Sunrise increased 23.6 thousand barrels per day and 21.8 thousand barrels per day, respectively, in the three and nine months ended September 30, 2023, compared with 2022. In addition, successful results from our 2023 redevelopment program completed in the third quarter increased production quarter-over-quarter.

Production from our Lloydminster thermal assets increased slightly in the three and nine months ended September 30, 2023, compared with 2022. The increases are due to first oil at the Spruce Lake North thermal plant in August 2022, partially offset by wells taken offline for a redevelopment program and workover activity in the first nine months of 2023.

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.

For the three and nine months ended September 30, 2023, royalties were $1.1 billion and $2.2 billion, respectively (2022 – $1.1 billion and $3.7 billion, respectively). In the first nine months of 2023, total Oil Sands effective royalty rates decreased to 21.1 percent from 25.4 percent in 2022 primarily due to lower realized pricing and lower Alberta oil sands sliding scale royalty rates.

Expenses

Transportation and Blending

In the third quarter of 2023, blending costs decreased $432 million to $1.9 billion compared with 2022, as we benefited from blending condensate purchased earlier in the quarter at lower prices as compared to 2022 where the cost of condensate used for blending was higher. In the first nine months of 2023, blending costs decreased $1.3 billion to $6.6 billion compared with 2022. On a year-to-date basis, the declines were largely due to lower condensate prices, partially offset by higher sales volumes.

Transportation costs of $432 million in the third quarter of 2023 were consistent with 2022. In the first nine months of 2023, transportation costs rose $147 million to $1.4 billion, due to higher tariff rates.

Per-unit Transportation Expenses

Transportation costs were $7.41 per BOE and $8.16 per BOE in the three and nine months ended September 30, 2023, respectively (2022 – $7.72 per BOE and $7.48 per BOE, respectively).

At Foster Creek, per-unit transportation costs were $10.55 per barrel and $12.20 per barrel in the three and nine months ended September 30, 2023, respectively (2022 – $11.96 per barrel and $10.71 per barrel, respectively). The quarter-over-quarter decrease was mainly due to higher sales volumes. The year-over-year increase primarily was due to lower sales volumes and higher tariff costs. In the three and nine months ended September 30, 2023, we shipped 44 percent and 46 percent, respectively (2022 – 41 percent and 42 percent, respectively) of our volumes from Foster Creek to U.S. destinations.

At Christina Lake, transportation costs were $5.76 per barrel and $6.46 per barrel in the three and nine months ended September 30, 2023 (2022 – $6.02 per barrel and $6.37 per barrel, respectively). The quarter-over-quarter decrease was primarily due to lower fixed rail costs. The year-over-year increase was mainly due to higher tariff rates, partially offset by lower fixed rail costs. In the three and nine months ended September 30, 2023, we shipped 14 percent and 17 percent, respectively (2022 – 11 percent and 14 percent, respectively) of our volumes from Christina Lake to U.S. destinations.

At Sunrise, transportation costs in the three and nine months ended September 30, 2023, were $12.29 per barrel and $12.49 per barrel, respectively (2022 – $13.17 per barrel and $12.96 per barrel, respectively). The quarter-over-quarter decrease was due to higher gross sales volumes, partially offset by a higher percentage of volumes shipped to U.S. destinations. The year-over-year decrease was mainly due to a lower percentage of volumes shipped to U.S. destinations. In the three and nine months ended September 30, 2023, we shipped 51 percent and 49 percent, respectively (2022 – 39 percent and 51 percent, respectively) of our volumes from Sunrise to U.S. destinations.

At our other Oil Sands assets, transportation costs in the three and nine months ended September 30, 2023, were $3.29 per barrel and $3.54 per barrel, respectively (2022 – $3.57 per barrel and $3.45 per barrel, respectively).

Operating

Primary drivers of our operating expenses in the first nine months of 2023 were fuel, workforce, repairs and maintenance, and chemicals. Total operating expenses were relatively flat in the third quarter of 2023 compared with 2022, and decreased in the first nine months of 2023 compared with 2022. Fuel costs decreased as a result of significant declines in AECO benchmark prices in the three and nine months ended September 30, 2023, compared with 2022. The decreases were offset by higher repairs and maintenance costs in the three and nine months ended September 30, 2023, compared with 2022.

Unit Operating Expenses [(1)]

	Three Months Ended September 30,			Nine Months Ended September 30,		
($/BOE)	**2023**	**Percent Change**	2022	**2023**	**Percent Change**	2022
Foster Creek						
Fuel	**2.83**	**(52)**	5.91	**3.76**	**(35)**	5.77
Non-Fuel	**8.08**	**7**	7.55	**8.24**	**15**	7.19
Total	**10.91**	**(19)**	13.46	**12.00**	**(7)**	12.96
Christina Lake						
Fuel	**2.87**	**(36)**	4.46	**3.13**	**(37)**	5.00
Non-Fuel	**6.45**	**36**	4.73	**5.71**	**14**	5.01
Total	**9.32**	**1**	9.19	**8.84**	**(12)**	10.01
Sunrise						
Fuel	**4.13**	**(46)**	7.58	**4.98**	**(36)**	7.78
Non-Fuel	**11.81**	**16**	10.16	**13.18**	**22**	10.76
Total	**15.94**	**(10)**	17.74	**18.16**	**(2)**	18.54
Other Oil Sands [(2)]						
Fuel	**4.25**	**(11)**	4.77	**4.69**	**(34)**	7.13
Non-Fuel	**15.82**	**(2)**	16.10	**16.42**	**11**	14.85
Total	**20.07**	**(4)**	20.87	**21.11**	**(4)**	21.98
Total Oil Sands						
Fuel	**3.24**	**(37)**	5.14	**3.79**	**(35)**	5.81
Non-Fuel	**9.32**	**13**	8.26	**9.30**	**16**	8.02
Total	**12.56**	**(6)**	13.40	**13.09**	**(5)**	13.83

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

Per-unit fuel prices decreased due to lower natural gas prices as discussed above. Per-unit fuel prices were also impacted by the timing and value of sales out of inventory.

Foster Creek per-unit non-fuel costs increased in the three and nine months ended September 30, 2023, compared with 2022. The quarter-over-quarter increase was due to higher repairs and maintenance costs, partially offset by higher sales volumes and the impact of the planned maintenance and unplanned outage in the third quarter of 2022. The year-to-date increase was due to lower sales volumes in 2023 combined with costs related to the planned turnaround in the second quarter of 2023, partially offset by the planned maintenance and unplanned outage in the third quarter of 2022.

Christina Lake per-unit non-fuel costs increased in the three and nine months ended September 30, 2023, compared with 2022, primarily due to lower sales volumes in 2023 combined with a planned turnaround completed in the third quarter of 2023. The year-to-date increase was partially offset by the impacts of planned turnaround in the second quarter of 2022.

Sunrise per-unit non-fuel costs increased in the three months ended September 30, 2023, compared with 2022 mainly due to higher workover activity and repairs and maintenance costs, partially offset by higher gross sales volumes in 2023. The per-unit non-fuel costs increased in the nine months ended September 30, 2023, compared with 2022 due to lower gross sales volumes in 2023 combined with higher electricity and repairs and maintenance costs.

Per-unit non-fuel costs at our other Oil Sands assets were relatively consistent in the third quarter of 2023 compared with 2022. Year-to-date, per-unit non-fuel costs increased from 2022, primarily due to higher workover activity and repairs and maintenance costs.

Netbacks [(1)]

($/BOE)	Three Months Ended September 30, 2023	2022	Nine Months Ended September 30, 2023	2022
Sales Price	**94.45**	84.29	**74.08**	99.78
Royalties	**19.70**	21.26	**13.91**	23.20
Transportation	**7.41**	7.72	**8.16**	7.48
Operating Expenses	**12.56**	13.40	**13.09**	13.83
Netback	**54.78**	41.91	**38.92**	55.27

(1) The components of netbacks are specified financial measures. Netbacks contain a Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

DD&A

In the three months and nine months ended September 30, 2023, DD&A was $785 million and $2.2 billion, respectively (2022 – $652 million and $2.0 billion, respectively). The average depletion rate for the three and nine months ended September 30, 2023, was $12.96 per BOE and $12.90 per BOE, respectively (2022 – $11.63 per BOE and $11.83 per BOE, respectively).

Conventional

In the third quarter of 2023, we:

- Delivered safe and reliable operations.
- Produced 127.2 thousand BOE per day (2022 – 126.2 thousand BOE per day).
- Substantially returned to full operations following significant wildfire activity in the second quarter of 2023. Additional wildfire activity impacted our Rainbow Lake property in September and had minor impacts on production.
- Generated Operating Margin of $126 million, a decrease from $290 million in 2022 due to lower average realized sales prices.
- Invested capital of $100 million with continued focus on drilling, completion, tie-in and infrastructure projects.
- Averaged a Netback of $9.66 per BOE (2022 – $24.06 per BOE).

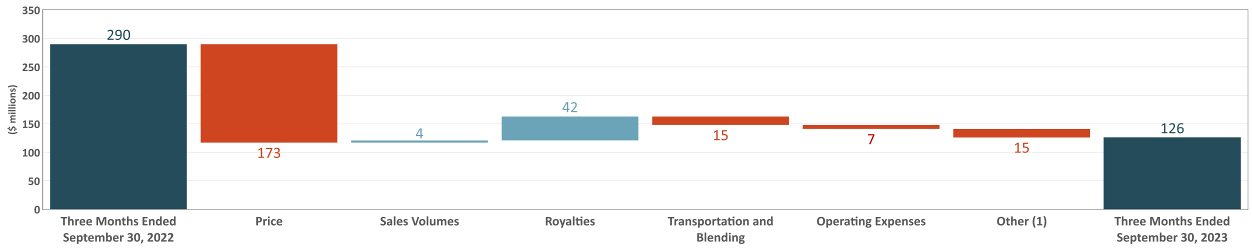
Financial Results

($ millions)	Three Months Ended September 30, 2023	2022	Nine Months Ended September 30, 2023	2022
Revenues				
Gross Sales [(1)]	**810**	1,036	**2,467**	3,286
Less: Royalties	**27**	68	**85**	228
	783	968	**2,382**	3,058
Expenses				
Purchased Product	**438**	464	**1,258**	1,460
Transportation and Blending [(1)]	**73**	64	**220**	191
Operating	**150**	141	**444**	403
Realized (Gain) Loss on Risk Management	**(4)**	9	**—**	17
Operating Margin	**126**	290	**460**	987
Unrealized (Gain) Loss on Risk Management	**7**	8	**(14)**	7
Depreciation, Depletion and Amortization	**104**	103	**286**	282
Exploration Expense	**—**	—	**—**	1
Segment Income (Loss)	**15**	179	**188**	697

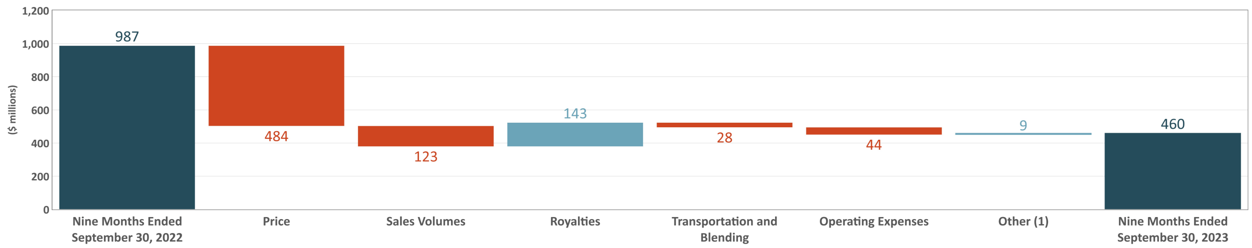
(1) Comparative periods reflect certain revisions. See Note 26 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Operating Margin Variance

Three Months Ended September 30, 2023



Nine Months Ended September 30, 2023



(1) Reflects Operating Margin from processing facilities.

Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	**2023**	2022
Total Sales Volumes (MBOE/d)	**127.2**	126.2	**118.5**	128.0
Total Realized Price [(1)] ($/BOE)	**28.13**	44.07	**32.70**	48.17
Light Crude Oil [(1)] ($/bbl)	**105.43**	132.08	**104.19**	125.99
NGLs [(1)] ($/bbl)	**47.74**	55.80	**47.52**	61.98
Conventional Natural Gas [(1)] ($/Mcf)	**3.05**	5.93	**4.19**	6.48
Production by Product				
Light Crude Oil (Mbbls/d)	**6.3**	6.9	**5.8**	7.8
NGLs (Mbbls/d)	**23.9**	19.9	**21.3**	23.0
Conventional Natural Gas (MMcf/d)	**582.1**	596.1	**548.8**	583.1
Total Production (MBOE/d)	**127.2**	126.2	**118.5**	128.0
Conventional Natural Gas Production (percentage of total)	**76**	79	**77**	76
Crude Oil and NGLs Production (percentage of total)	**24**	21	**23**	24
Effective Royalty Rate (percent)	**9.6**	15.9	**10.7**	15.3
Transportation Expense [(1)] ($/BOE)	**3.82**	2.43	**3.97**	2.85
Operating Expense [(1)] ($/BOE)	**12.36**	11.77	**13.26**	11.03
Per Unit DD&A [(1)] ($/BOE)	**8.82**	8.51	**8.77**	8.23

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

Revenues

Price

Our total realized sales price decreased in the three and nine months ended September 30, 2023, due to lower crude oil and natural gas benchmark prices.

For the three and nine months ended September 30, 2023, gross sales included $438 million and $1.3 billion, respectively (2022 – $464 million and $1.5 billion, respectively), relating to third-party sourced volumes.

For the three and nine months ended September 30, 2023, gross sales included amounts relating to processing and transportation activities undertaken for third parties of $42 million and $150 million, respectively (2022 – $60 million and $143 million, respectively).

Production Volumes

Production volumes were relatively consistent in the third quarter of 2023 compared with 2022, and decreased 9.5 thousand BOE per day in the first nine months of 2023 compared with 2022. Third quarter volumes were positively impacted by successful results from our 2023 development program which offset natural declines. The year-over-year decrease was primarily due to the impact of the wildfires in the second quarter of 2023. In early May, approximately 85 thousand BOE per day of production was temporarily shut-in in response to the wildfires. The majority of our wells and facilities impacted by the fires were restarted in June, and the outages were substantially resolved by late August. In late September additional wildfire activity impacted our Rainbow Lake property, from which production impacts on the quarter were minimal. Production was brought back online in October as power infrastructure was restored.

Royalties

The Conventional assets are subject to royalty regimes in Alberta and British Columbia. Effective royalty rates decreased in the three and nine months ended September 30, 2023, compared with the same periods in 2022 primarily due to sharp declines in natural gas pricing and the impact of wildfires. In addition, the year-over-year decrease was impacted by higher gas cost allowance (“GCA”) deductions. In Alberta, natural gas wells benefit from GCA which reduces royalties to account for capital and operating costs incurred to process and transport the Crown’s portion of natural gas production. Total royalties in the three and nine months ended September 30, 2023, decreased compared with the same periods of 2022 due to the same factors impacting effective royalty rates.

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. In the third quarter of 2023, transportation costs increased $9 million to $73 million, compared with 2022, and per-unit transportation costs averaged $3.82 per BOE in 2023, compared with $2.43 per BOE in 2022. The increases were due to higher rates and additional storage costs. Year-to-date, transportation costs increased $29 million to $220 million, and per-unit transportation costs averaged $3.97 per BOE, compared with $2.85 per BOE in 2022. The per BOE increases were mainly due to the same factors impacting the third quarter combined with the impacts of the wildfires.

Operating

Primary drivers of operating expenses in the first nine months of 2023 were repairs and maintenance, workforce, property taxes and lease costs, and electricity. Total operating expenses increased $9 million to $150 million quarter-over-quarter and $41 million to $444 million year-over-year due to the higher repairs and maintenance costs. The wildfires had minimal impact on total operating expenses. Operating expenses per BOE increased $0.59 per BOE quarter-over-quarter and $2.23 per BOE year-over-year due to the same factors impacting total operating costs. Year-to-date, operating expenses per BOE also increased due to lower sales volumes as a result of wildfire activity.

Netbacks (1)

	Three Months Ended September 30,		Nine Months Ended September 30,	
($/BOE)	**2023**	2022	**2023**	2022
Sales Price	**28.13**	44.07	**32.70**	48.17
Royalties	**2.29**	5.81	**2.64**	6.49
Transportation and Blending	**3.82**	2.43	**3.97**	2.85
Operating Expenses	**12.36**	11.77	**13.26**	11.03
Netback	**9.66**	24.06	**12.83**	27.80

(1) *The components of netbacks are specified financial measures. Netbacks contain a Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.*

DD&A

For the three and nine months ended September 30, 2023, total Conventional DD&A was $104 million and $286 million, respectively (2022 – $103 million and $282 million, respectively). The average depletion rate for the three and nine months ended September 30, 2023, was $8.82 per BOE and $8.77 per BOE, respectively (2022 – $8.51 per BOE and $8.23 per BOE, respectively).

Offshore

In the third quarter of 2023, we:

- Delivered safe and reliable operations.
- Saw the Terra Nova FPSO return to the field in August. Commissioning activities are ongoing with production expected to resume in the fourth quarter.
- Achieved first gas production from the MAC field in Indonesia in September.
- Produced 66.4 thousand BOE per day (2022 – 64.6 thousand BOE per day).
- Generated Operating Margin of $300 million, a decrease of $39 million compared with 2022, largely due to decreased realized light crude oil and NGLs sales prices.
- Earned a Netback of $57.87 per BOE (2022 – $66.81 per BOE).
- Invested capital of $194 million mainly for the West White Rose project and Terra Nova ALE project in the Atlantic region.

The West White Rose project was approximately 75 percent complete as at September 30, 2023. Since our decision to restart the project, we have invested approximately $440 million. We reached a major milestone on the project in the second quarter with the completion of the conical slip form operation for the concrete gravity structure.

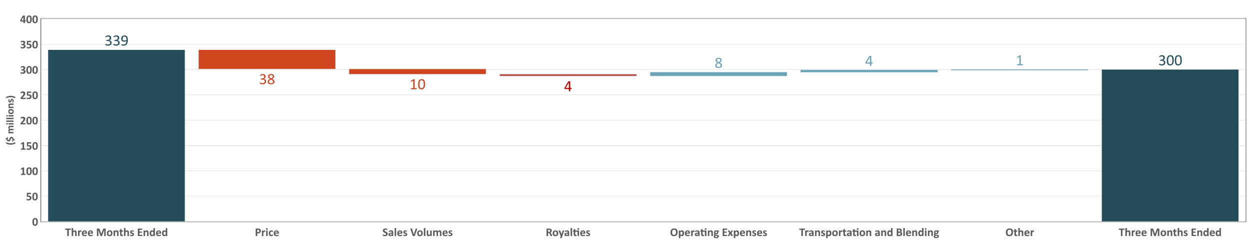
Financial Results

	Three Months Ended September 30,					
	2023			2022		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore**	Atlantic	Asia Pacific	Offshore
Revenues						
Gross Sales	**78**	**324**	**402**	113	337	450
Less: Royalties	**2**	**24**	**26**	2	20	22
	76	**300**	**376**	111	317	428
Expenses						
Transportation and Blending	**—**	**—**	**—**	4	—	4
Operating	**47**	**29**	**76**	53	32	85
Operating Margin (1)	**29**	**271**	**300**	54	285	339
Depreciation, Depletion and Amortization			**130**			132
Exploration Expense			**2**			66
(Income) Loss from Equity-Accounted Affiliates			**(11)**			(9)
Segment Income (Loss)			**179**			150

(1) *Atlantic and Asia Pacific 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, 2023

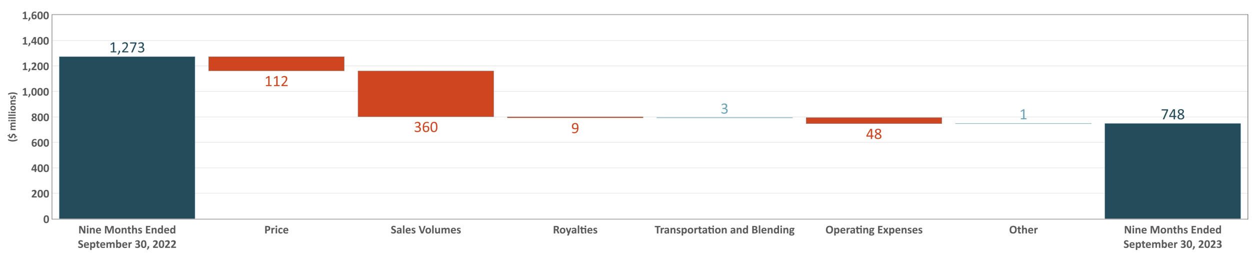


	Nine Months Ended September 30,					
	2023			2022		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore**	Atlantic	Asia Pacific	Offshore
Revenues						
Gross Sales	**232**	**871**	**1,103**	492	1,083	1,575
Less: Royalties	**11**	**54**	**65**	(4)	60	56
	221	**817**	**1,038**	496	1,023	1,519
Expenses						
Transportation and Blending	**9**	**—**	**9**	12	—	12
Operating	**190**	**91**	**281**	146	88	234
Operating Margin (1)	**22**	**726**	**748**	338	935	1,273
Depreciation, Depletion and Amortization			**349**			441
Exploration Expense			**6**			91
(Income) Loss from Equity-Accounted Affiliates			**(29)**			(19)
Segment Income (Loss)			**422**			760

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

Operating Margin Variance

Nine Months Ended September 30, 2023



Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2023	2022	**2023**	2022
Sales Volumes				
Atlantic (Mbbls/d)	**7.8**	7.8	**7.8**	12.6
Asia Pacific (MBOE/d)				
China	**43.8**	45.4	**39.4**	48.6
Indonesia (1)	**13.7**	10.1	**14.1**	9.7
Total Asia Pacific	**57.5**	55.5	**53.5**	58.3
Total Sales Volumes (MBOE/d)	**65.3**	63.3	**61.3**	70.9
Total Realized Price (2) ($/BOE)	**79.27**	88.02	**79.42**	91.32
Atlantic - Light Crude Oil (2) ($/bbl)	**107.99**	158.42	**108.48**	142.96
Asia Pacific (1)(2) ($/BOE)	**75.38**	78.19	**75.18**	80.16
NGLs (2) ($/bbl)	**101.97**	108.39	**95.36**	113.04
Conventional Natural Gas (2) ($/Mcf)	**11.43**	11.62	**11.70**	11.88
Production by Product				
Atlantic - Light Crude Oil (Mbbls/d)	**8.9**	9.1	**7.7**	12.0
Asia Pacific (1)				
NGLs (Mbbls/d)	**11.7**	12.2	**10.6**	12.4
Conventional Natural Gas (MMcf/d)	**274.7**	260.0	**257.3**	275.3
Total Asia Pacific (MBOE/d)	**57.5**	55.5	**53.5**	58.3
Total Production (MBOE/d)	**66.4**	64.6	**61.2**	70.3
Effective Royalty Rate (percent)				
Atlantic	**2.4**	1.8	**4.6**	(0.8)
Asia Pacific (1)	**9.8**	11.1	**10.0**	11.7
Operating Expense (2) ($/BOE)	**14.66**	12.55	**17.37**	12.24
Atlantic (2)	**65.91**	47.23	**78.61**	36.79
Asia Pacific (1)(2)	**7.73**	7.70	**8.42**	6.94
Per Unit DD&A (2) ($/BOE)	**26.29**	30.89	**26.00**	30.29

(1) Reported sales volumes, associated per-unit values and royalty rates reflect Cenovus's 40 percent interest in HCML. 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 decreased in the three and nine months ended September 30, 2023, compared with 2022, primarily due to lower Brent benchmark pricing.

Production Volumes

Atlantic production was relatively consistent in the third quarter of 2023 compared with 2022 and decreased 4.3 thousand barrels per day in the nine months ended September 30, 2023, compared with 2022. The decrease was due to turnaround work on the SeaRose FPSO completed in March and April of 2023 having a larger impact than annual planned maintenance completed in the third quarter in 2022. In addition, the decrease in Cenovus's working interest at the White Rose field and satellite extensions effective May 31, 2022, lowered production year-over-year. Light crude 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, which results in a timing difference between production and sales.

Asia Pacific production increased slightly in the third quarter of 2023 compared with 2022 and decreased 4.8 thousand barrels per day in the nine months ended September 30, 2023, compared with 2022. The year-over-year decrease was mainly due to a temporary unplanned outage in the second quarter in China, related to the disconnection of the umbilical cord by a third-party vessel in early April and reconnected in May. Changes to gas sales agreements at Liwan 3-1 and Liuhua 29-1 in the second quarter of 2022 also resulted in a net decrease in production. The decrease was partially offset by first gas production at the MBH and MDA fields in Indonesia in the fourth quarter of 2022, and planned maintenance in China in the second and third quarters of 2022 having a larger impact than planned maintenance in June 2023. We drilled and completed the third of three planned development wells at the MAC field Indonesia in the first quarter of 2023, and achieved first gas production from the field in September.

Royalties

In the three and nine months ended September 30, 2023, Atlantic royalties were $2 million and $11 million, respectively (2022 – $2 million and recoveries of $4 million, respectively). In 2022, royalties at the White Rose field included year-to-date adjustments based on an amended agreement between our working interest partners and the Government of Newfoundland and Labrador.

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 rate for the three and nine months ended September 30, 2023, declined to 9.8 percent and 10.0 percent, respectively (2022 – 11.1 percent and 11.7 percent, respectively), as a result of first gas production at the MBH and MDA fields starting in the fourth quarter of 2022.

Expenses

Operating

Primary drivers of our Atlantic operating expenses in the first nine months of 2023 were repairs and maintenance, vessel and helicopter costs, and workforce. In the third quarter of 2023, operating costs decreased slightly from 2022 to $47 million. Operating expenses in the first nine months of 2023 increased $44 million, to $190 million, due to the ramp-up of the West White Rose project leading up to the start of major construction in late March, costs related to turnaround work on the SeaRose FPSO in the second quarter and costs associated with preparation and maintenance activities for the Terra Nova FPSO. Per-unit operating expenses increased in the nine months ended September 30, 2023, compared with 2022 due to lower sales volumes combined with the same factors that impacted total operating expenses.

Primary drivers of our Asia Pacific operating expenses in the first nine months of 2023 were repairs and maintenance, insurance and workforce. Total operating expenses declined slightly in the three months ended September 30, 2023 and increased slightly on a year-to-date basis, compared with the same periods in 2022. Per-unit operating expenses were consistent in the third quarter of 2023 compared with 2022. Year-to-date, per-unit operating expenses increased compared with 2022 mainly due to lower sales volumes.

Transportation

Transportation costs in the Atlantic region decreased in the three and nine months ended September 30, 2023, compared with the same periods of 2022 and includes the cost of transporting crude oil from the SeaRose FPSO unit to onshore via tankers, as well as storage costs.

Netbacks [1]

($/BOE, except where indicated)	Three Months Ended September 30, 2023			
	Atlantic ($/bbl)	**China**	**Indonesia** [2]	**Total Offshore**
Sales Price	**107.99**	**80.61**	**58.68**	**79.27**
Royalties	**2.56**	**6.06**	**11.59**	**6.80**
Transportation and Blending	**(0.53)**	**—**	**—**	**(0.06)**
Operating Expenses	**65.91**	**6.51**	**11.66**	**14.66**
Netback	**40.05**	**68.04**	**35.43**	**57.87**

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

($/BOE, except where indicated)	Nine Months Ended September 30, 2023			
	Atlantic ($/bbl)	**China**	**Indonesia** [2]	**Total Offshore**
Sales Price	**108.48**	**81.09**	**58.71**	**79.42**
Royalties	**4.94**	**5.05**	**14.44**	**7.20**
Transportation and Blending	**4.02**	**—**	**—**	**0.51**
Operating Expenses	**78.61**	**7.60**	**10.72**	**17.37**
Netback	**20.91**	**68.44**	**33.55**	**54.34**

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

(1) The components of netbacks are specified financial measures. Netbacks contain a Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Reported sales volumes, associated per-unit values and royalty rates reflect Cenovus's 40 percent interest in HCML. Revenues and expenses related to the HCML joint venture are accounted for using the equity method in the consolidated financial statements.

Exploration Expense

We recorded exploration expense of $6 million in the first nine months of 2023 (2022 – $91 million). Exploration expense in 2022 was primarily due to a $58 million write-off related to our decision not to pursue development at block 15/33 in China.

DD&A

In the three and nine months ended September 30, 2023, total Offshore DD&A was $130 million and $349 million, respectively (2022 – $132 million and $441 million, respectively). The average depletion rate in the three and nine months ended September 30, 2023, was $26.29 per BOE and $26.00 per BOE, respectively (2022 – $30.89 per BOE and $30.29 per BOE, respectively).

DOWNSTREAM

Canadian Manufacturing

In the third quarter of 2023, we:

- Delivered safe and reliable operations.
- Had very strong performance at the Upgrader and Lloydminster Refinery, achieving crude utilization of 98 percent (2022 – 89 percent).
- Generated Operating Margin of $170 million, a decrease of $76 million compared with 2022, primarily due to lower synthetic crude oil prices relative to crude oil feedstock, and lower refined product prices, partially offset by increased production volumes.

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2023**	2022	**2023**	2022
Revenues	**1,805**	2,168	**4,676**	6,020
Purchased Product	**1,480**	1,750	**3,656**	5,065
Gross Margin (1)	**325**	418	**1,020**	955
Expenses				
Operating	**155**	172	**471**	534
Operating Margin	**170**	246	**549**	421
Depreciation, Depletion and Amortization	**50**	42	**136**	164
Segment Income (Loss)	**120**	204	**413**	257

(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,	
	2023	2022	**2023**	2022
Total Canadian Manufacturing				
Heavy Crude Oil Unit Throughput Capacity [1] (Mbbls/d)	**110.5**	110.5	**110.5**	110.5
Heavy Crude Oil Unit Throughput (Mbbls/d)	**108.4**	98.5	**100.8**	92.5
Crude Utilization (percent)	**98**	89	**91**	84
Total Production (Mbbls/d)	**122.4**	111.0	**114.6**	104.2
Synthetic Crude Oil	**53.2**	47.7	**47.9**	46.3
Asphalt	**15.7**	15.5	**15.6**	13.3
Diesel	**13.8**	10.5	**12.8**	9.0
Other	**34.1**	32.2	**33.4**	30.8
Ethanol	**5.6**	5.1	**4.9**	4.8
Refining Margin [2] ($/bbl)	**29.17**	38.88	**33.48**	29.69
Unit Operating Expense [3] ($/bbl)	**11.60**	11.72	**12.44**	13.95
Lloydminster Upgrader				
Heavy Crude Oil Unit Throughput Capacity [1] (Mbbls/d)	**81.5**	81.5	**81.5**	81.5
Heavy Crude Oil Unit Throughput [4] (Mbbls/d)	**80.6**	71.3	**72.9**	68.8
Crude Utilization (percent)	**99**	87	**89**	84
Production (Mbbls/d)	**88.9**	78.6	**81.8**	75.7
Refining Margin [2] ($/bbl)	**29.12**	38.33	**34.82**	30.49
Unit Operating Expense [3] ($/bbl)	**11.29**	11.25	**12.35**	12.59
Upgrading Differential [5] ($/bbl)	**22.31**	39.36	**29.63**	28.69
Lloydminster Refinery				
Heavy Crude Oil Unit Throughput Capacity [1] (Mbbls/d)	**29.0**	29.0	**29.0**	29.0
Heavy Crude Oil Unit Throughput (Mbbls/d)	**27.8**	27.2	**27.9**	23.7
Crude Utilization (percent)	**96**	94	**96**	82
Production (Mbbls/d)	**27.9**	27.3	**27.9**	23.7
Refining Margin [2] ($/bbl)	**29.30**	40.33	**29.98**	27.38
Unit Operating Expense [3] ($/bbl)	**12.51**	12.96	**12.70**	17.89
Ethanol				
Ethanol Production (Mbbls/d)	**5.6**	5.1	**4.9**	4.8
Rail				
Volumes Loaded [6] (Mbbls/d)	**—**	1.4	**1.2**	1.5

(1) Based on crude oil name plate capacity.
(2) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A. Revenues from the Upgrader and commercial fuels business for the three and nine months ended September 30, 2023, were $1.6 billion and $4.2 billion, respectively (2022 – $998 million and $2.9 billion, respectively, from the Upgrader). Revenues from the Lloydminster Refinery for the three and nine months ended September 30, 2023 were $325 million and $739 million, respectively (2022 – $387 million and $816 million, respectively).
(3) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(4) Upgrader throughput includes diluent returned to the field.
(5) Based on benchmark price differential between heavy oil feedstock and synthetic crude.
(6) Total crude oil volumes loaded and transported outside of Alberta, Canada.

In the third quarter of 2023, Canadian Manufacturing throughput increased 9.9 thousand barrels per day from 2022 to 108.4 thousand barrels per day, and total production increased 11.4 thousand barrels per day to 122.4 thousand barrels per day due to:

- Strong performance at the Upgrader in 2023 combined with temporary unplanned outages in the third quarter of 2022 resulted in crude utilization of 99 percent (2022 – 87 percent).
- Continued strong performance at the Lloydminster Refinery with throughput of 27.8 thousand barrels per day compared with 27.2 thousand barrels per day.

In the nine months ended September 30, 2023, Canadian Manufacturing throughput increased by 8.3 thousand barrels per day to 100.8 thousand barrels per day, and total production increased by 10.4 thousand barrels per day to 114.6 thousand barrels per day compared with the same period in 2022 due to the same factors as discussed above, combined with:

- Increased throughput at the Upgrader which rose 4.1 thousand barrels per day to 72.9 thousand barrels per day due to planned turnarounds and unplanned outages in 2022, partially offset by an unplanned outage in the second quarter of 2023 and unplanned outages and cold weather impacts in the fourth quarter of 2022 that continued to impact Cenovus in early January 2023.
- Higher crude utilization at the Lloydminster Refinery, which increased to 96 percent (2022 – 82 percent) primarily due to a temporary unplanned outage in the third quarter of 2022 and a planned turnaround in the second quarter of 2022.

Revenues and Gross Margin

The Upgrader processes blended heavy crude oil and bitumen into high value synthetic crude oil and low sulphur diesel. 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.

The Lloydminster Refinery processes blended heavy crude oil into asphalt and industrial products. 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 Upgrader and Lloydminster Refinery source crude oil feedstock from our Lloydminster thermal and Lloydminster conventional heavy oil production.

In the third quarter of 2023, total revenues from Canadian Manufacturing decreased by $363 million to $1.8 billion compared with 2022, due to lower synthetic crude, refined product and industrial product pricing and the disposition of our retail fuels business in the third quarter of 2022. The decrease was partially offset by higher production compared with the same period in 2022. In the first nine months of 2023, revenues decreased by $1.3 billion to $4.7 billion due to the reasons discussed above. In the three and nine months ended September 30, 2023, synthetic crude oil benchmark prices decreased 15 percent and 22 percent to US$84.95 per barrel and US$79.93 per barrel, respectively, compared with 2022.

Gross margin decreased $93 million to $325 million in the third quarter of 2023 compared with 2022 due to the factors noted above, in addition to weakened upgrading differentials and lower refining margins.

Gross margin increased $65 million to $1.0 billion in the first nine months of 2023 compared with 2022 due to a higher upgrading differential, improved refining margins and increased throughput at the Upgrader and Lloydminster Refinery. The increase was partially offset by the disposition of our retail fuels network in the third quarter of 2022. Improved refining and upgrading margins were primarily driven by lower heavy crude oil feedstock cost. In the three and nine months ended September 30, 2023, WCS prices decreased by 3 percent and 27 percent to US$69.35 per barrel and US$59.82 per barrel, respectively, compared with 2022.

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 first nine months of 2023 were repairs and maintenance, workforce, chemical, electricity and energy costs.

Total and per-unit operating costs decreased in the three and nine months ended September 30, 2023, compared with 2022, mainly due to the disposition of our retail fuels network in the third quarter of 2022, lower energy costs and higher throughput. Year-to-date costs also decreased due to planned turnarounds at the Upgrader and Lloydminster Refinery in the second quarter of 2022. The decreases were partially offset by higher repairs and maintenance spend at the Upgrader in the third quarter of 2023. Per-unit operating expenses apply only to operating costs and throughput at the Upgrader and Lloydminster Refinery.

DD&A

In the three and nine months ended September 30, 2023, DD&A was $50 million and $136 million, respectively (2022 – $42 million and $164 million, respectively).

U.S. Manufacturing

In the third quarter of 2023, we:

- Delivered safe operations.
- Generated Operating Margin of $752 million, an increase of $508 million compared with 2022, primarily due to the Toledo Acquisition, higher refining margins and the Toledo and Superior refineries being operational. We continue to find ways to integrate the Lima and Toledo refineries to optimize our operating margin.
- Progressed the restart of the FCCU at the Superior Refinery, which was brought online in early October, and generated crude throughput of 32.2 thousand barrels per day.
- Achieved crude utilization of 88 percent (2022 – 87 percent).
- Commenced a planned turnaround at the Borger Refinery in late September. The turnaround is expected to be completed in the fourth quarter of 2023.
- Invested capital of $88 million.

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2023**	2022	**2023**	2022
Revenues [(1)]	**7,853**	8,705	**19,546**	23,688
Purchased Product [(1)]	**6,467**	7,930	**16,729**	20,351
Gross Margin [(2)]	**1,386**	775	**2,817**	3,337
Expenses				
Operating	**623**	608	**1,904**	1,757
Realized (Gain) Loss on Risk Management	**11**	(77)	**6**	120
Operating Margin	**752**	244	**907**	1,460
Unrealized (Gain) Loss on Risk Management	**(2)**	(8)	**(13)**	(22)
Depreciation, Depletion and Amortization	**109**	91	**314**	259
Segment Income (Loss)	**645**	161	**606**	1,223

(1) Comparative periods reflect certain revisions. See Note 26 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

(2) 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,	
	2023	2022	**2023**	2022
Total U.S. Manufacturing				
Crude Oil Unit Throughput Capacity (1) (Mbbls/d)	**635.2**	502.5	**635.2**	502.5
Crude Oil Unit Throughput (Mbbls/d)	**555.9**	435.0	**453.3**	405.3
Heavy Crude Oil	**210.6**	145.2	**165.4**	135.2
Light and Medium Crude Oil	**345.3**	289.8	**287.9**	270.1
Crude Utilization (2) (percent)	**88**	87	**75**	81
Total Refined Product Production (Mbbls/d)	**583.6**	461.6	**475.2**	426.7
Gasoline	**267.6**	212.5	**218.3**	202.0
Distillates (3)	**196.1**	172.7	**165.2**	155.3
Asphalt	**24.7**	10.3	**19.2**	8.8
Other	**95.2**	66.1	**72.5**	60.6
Refining Margin (4) ($/bbl)	**27.10**	18.98	**22.77**	29.94
Unit Operating Expense (5) ($/bbl)	**12.17**	14.90	**15.39**	15.77
Lima Refinery				
Crude Oil Unit Throughput Capacity (1) (6) (Mbbls/d)	**178.7**	175.0	**178.7**	175.0
Crude Oil Unit Throughput (Mbbls/d)	**146.2**	164.2	**159.7**	153.5
Crude Utilization (percent)	**82**	94	**89**	88
Toledo Refinery (7)				
Crude Oil Unit Throughput Capacity (1) (Mbbls/d)	**160.0**	80.0	**160.0**	80.0
Crude Oil Unit Throughput (Mbbls/d)	**143.5**	46.6	**64.5**	48.5
Crude Utilization (2) (percent)	**90**	58	**45**	61
Superior Refinery				
Crude Oil Unit Throughput Capacity (1) (Mbbls/d)	**49.0**	—	**49.0**	—
Crude Oil Unit Throughput (Mbbls/d)	**32.2**	—	**19.3**	—
Crude Utilization (2) (percent)	**66**	—	**59**	—
Wood River and Borger Refineries (8)				
Crude Oil Unit Throughput Capacity (1) (Mbbls/d)	**247.5**	247.5	**247.5**	247.5
Crude Oil Unit Throughput (Mbbls/d)	**234.0**	224.2	**209.8**	203.3
Crude Utilization (percent)	**95**	91	**85**	82

(1) Based on crude oil name plate capacity.
(2) The Superior Refinery's crude oil unit throughput and crude oil unit throughput capacity are included in the crude utilization calculation effective April 1, 2023. The Toledo Refinery's crude utilization includes a weighted average crude oil capacity with full ownership acquired on February 28, 2023.
(3) Includes diesel and jet fuel.
(4) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(5) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(6) The name plate capacity at the Lima Refinery increased effective January 1, 2023.
(7) On February 28, 2023, we purchased the remaining 50 percent interest in BP-Husky Refining LLC.
(8) Represents Cenovus's 50 percent interest in the non-operated Wood River and Borger refinery operations.

In the third quarter of 2023, U.S. Manufacturing throughput increased 120.9 thousand barrels per day from 2022 to 555.9 thousand barrels per day, and total refined product production increased 122.0 thousand barrels per day to 583.6 thousand barrels per day due to:

- Full ownership of the Toledo Refinery, that occurred on February 28, 2023. Crude throughput increased 96.9 thousand barrels per day to 143.5 thousand barrels per day in the third quarter of 2023 compared with the same period in 2022. The increase was also due to a significant planned turnaround in the second quarter of 2022 that was completed in the third quarter of 2022 and the incident that occurred in September 2022. Crude utilization at the Toledo Refinery was 90 percent (2022 – 58 percent).
- Continued work on the restart of the FCCU at the Superior Refinery, which was brought online in early October. Refined product output averaged 33.1 thousand barrels per day in the third quarter of 2023.
- Strong performance from the Wood River Refinery, combined with a planned turnaround that commenced in September 2022. Total throughput for the Wood River and Borger refineries increased by 9.8 thousand barrels per day to 234.0 thousand barrels per day in the third quarter of 2023.

The increases were partially offset by unplanned outages and planned maintenance at the Lima Refinery in the third quarter of 2023.

In the first nine months of 2023, U.S. Manufacturing crude throughput increased 48.0 thousand barrels per day to 453.3 thousand barrels per day, and total refined product production increased 48.5 thousand barrels per day to 475.2 thousand barrels per day primarily related to operations at the Toledo and Superior refineries and for the same reasons discussed above, as well as:

- Increased throughput at the Wood River Refinery primarily due to the turnarounds in 2022 having a larger impact than in 2023 and the decision in the first quarter of 2022 to operate at reduced rates to optimize margins as market conditions dictated. Combined crude utilization for the Wood River and Borger refineries for the nine months ended September 30, 2023, was 85 percent (2022 – 82 percent).
- Lima Refinery's performance, achieving crude utilization of 89 percent during the nine months ended September 30 (2022 – 88 percent). Crude throughput increased 6.2 thousand barrels per day compared with the first nine months of 2022. The increase was due to feedstock pipeline and other temporary outages in 2022 and the decision to operate the refinery at reduced rates in early 2022 due to low market crack spreads. The increase was partially offset by the planned and unplanned outages discussed above.

Increased throughput was partially offset by a planned turnaround at the Borger Refinery in March and April 2023 and temporary unplanned outages in the second quarter of 2023. The turnaround and outages had a larger impact on throughput than the turnaround completed in the spring of 2022.

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, distillates and secondary product output, the time lag between the purchase of crude oil feedstock and the processing of that crude oil through the refineries, and the cost of feedstock. Processing less expensive crude relative to WTI creates a feedstock cost advantage. Our feedstock costs are valued on a FIFO accounting basis. In the three and nine months ended September 30, 2023, the Chicago 3-2-1 crack spread decreased 33 percent and 19 percent, respectively, to US$26.06 per barrel and US$27.83 per barrel, respectively, compared with 2022. In the three and nine months ended September 30, 2023, the Group 3 crack spread declined 4 percent and 3 percent, respectively, to US$36.96 per barrel and US$33.36 per barrel, respectively, compared with 2022.

Revenues decreased $852 million and $4.1 billion, respectively, in the three and nine months ended September 30, 2023, compared with 2022. The decreases were primarily due to lower refined product pricing, partially offset by higher production, primarily related to our Toledo and Superior refineries. Benchmark gasoline prices fell 13 percent and 19 percent, respectively, in the three and nine months ended September 30, 2023, compared with the same periods in 2022. Benchmark diesel prices also fell in the quarter and on a year-to-date basis, by US$34.47 and US$34.30, respectively, compared with the same periods in 2022.

Gross margin increased $611 million in the three months ended September 30, 2023 compared with the same period in 2022. The increase was largely due to higher refined product production, lower cost of feedstock processed and weakened RINs pricing of US$7.42 per barrel (2022 – US$8.11 per barrel). Gross margin decreased by $520 million in the nine months ended September 30, 2023 primarily due to lower market crack spreads, partially offset by higher production.

Operating Expenses

Primary drivers of operating expenses in the first nine months of 2023 were repairs and maintenance, and workforce.

Operating expenses increased $15 million in the three months ended September 30, 2023 compared with the same period in 2022 primarily due to operations at the Toledo and Superior refineries. The increases were due to:

- Higher chemical costs primarily due to increased consumption at the Toledo and Superior refineries and higher chemical pricing.
- Increased workforce costs at the Superior Refinery for restart and ramp-up activities and higher overall workforce costs related to the Toledo Acquisition, partially offset by increased workforce costs at the Toledo Refinery during the significant planned turnaround in 2022.
- Increased repairs and maintenance spend at the Lima Refinery.

The increases were partially offset by lower energy costs related to the decline in natural gas benchmark pricing.

Operating expenses increased by $147 million in the nine months ended September 30, 2023, compared with the same period in 2022 due to the reasons discussed above. The increase was partially offset by lower repairs and maintenance costs due to the significant planned turnaround at the Toledo Refinery in the second and third quarters of 2022 and lower energy costs, primarily due to the decline in natural gas benchmark pricing discussed above.

Per-unit operating expenses decreased $2.73 per barrel and $0.38 per barrel, respectively, in the three and nine months ended September 30, 2023, compared with the same period in 2022, primarily due to higher throughput and lower energy costs as noted above.

(Gain) Loss on Risk Management

In the three and nine months ended September 30, 2023, we incurred realized risk management losses of $11 million and $6 million, respectively (2022 – gains of $77 million and losses of $120 million, respectively), due to the settlement of benchmark prices relative to our risk management contract prices. In the three and nine months ended September 30, 2023, we recorded unrealized risk management gains of $2 million and $13 million, respectively (2022 – $8 million and $22 million, respectively), on our crude oil and refined products financial instruments primarily due to changes to forward benchmark pricing relative to our risk management contract prices that related to future periods.

DD&A

U.S. Manufacturing DD&A in the three and nine months ended September 30, 2023, was $109 million and $314 million, respectively, compared with $91 million and $259 million, respectively, in 2022. The increase is primarily due to the Toledo Acquisition.

CORPORATE AND ELIMINATIONS

Risk Management

In the three and nine months ended September 30, 2023, our corporate risk management activities resulted in:

- A realized risk management gain of $1 million and a loss of $2 million, respectively (2022 – losses of $16 million and $23 million, respectively), related to foreign exchange risk management contracts.
- Unrealized risk management losses of $20 million and $71 million, respectively (2022 – gains of $16 million $14 million, respectively), related to renewable power contracts and foreign exchange risk management contracts.

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2023**	2022	**2023**	2022
General and Administrative	**292**	128	**617**	545
Finance Costs	**106**	207	**493**	631
Interest Income	**(33)**	(21)	**(100)**	(44)
Integration and Transaction Costs	**12**	27	**49**	79
Foreign Exchange (Gain) Loss, Net	**133**	316	**7**	406
Revaluation (Gain) Loss	**—**	(549)	**33**	(549)
Re-measurement of Contingent Payments	**67**	(109)	**83**	142
(Gain) Loss on Divestiture of Assets	**—**	60	**(11)**	(244)
Other (Income) Loss, Net	**(22)**	(59)	**(42)**	(467)
	555	—	**1,129**	499

General and Administrative

Primary drivers of our general and administrative expenses in the first nine months of 2023 were employee long-term incentive costs, workforce costs and information technology costs. General and administrative expenses increased in the three months ended September 30, 2023, compared with 2022 primarily due to higher long-term incentive costs of $151 million (2022 – recovery of $1 million). In the nine months ended September 30, 2023, general and administrative expenses increased compared with 2022 due to higher information technology, building operating costs, workforce, indigenous housing initiative costs and long-term incentive costs of $196 million (2022 – $184 million).

Finance Costs

Finance costs were lower in the three and nine months ended September 30, 2023, compared with the same periods in 2022, primarily due to debt purchases in 2022 that lowered the Company's average long-term debt and interest expenses. In the third quarter of 2023, we purchased long-term debt with an aggregate principal amount of US$1.0 billion at a discount of $84 million compared with a purchase of long-term debt with an aggregate principal amount of US$2.2 billion at a discount of $4 million in the third quarter of 2022. Refer to the Liquidity and Capital Resources section of this MD&A for further details on long-term debt.

The weighted average interest rate on outstanding debt for the three and nine months ended September 30, 2023, was 4.7 percent (2022 – 4.8 percent and 4.7 percent, respectively).

Integration and Transaction Costs

In the three and nine months ended September 30, 2023, we incurred integration and transaction costs of $12 million and $49 million, respectively, associated with the Toledo Acquisition.

We incurred integration and transaction costs of $27 million and $79 million in the three and nine months ended September 30, 2022, respectively, not including capital expenditures, primarily related to the integration of Cenovus and Husky Energy Inc.

Foreign Exchange (Gain) Loss, Net

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
($ millions)	**2023**	2022	**2023**	2022
Unrealized Foreign Exchange (Gain) Loss	**59**	298	**(99)**	419
Realized Foreign Exchange (Gain) Loss	**74**	18	**106**	(13)
	133	316	**7**	406

In the third quarter of 2023, unrealized foreign exchange losses were mainly related to the translation of U.S. denominated debt. In the first nine months of 2023, unrealized foreign exchange gains were primarily caused by the translation of U.S. denominated debt. Realized foreign exchange losses in both periods in 2023 were mainly related to the settlement of fixed-term debt.

Revaluation (Gain) Loss

Cenovus recognized a revaluation loss of $33 million in the first quarter of 2023 as part of the Toledo Acquisition. In the third quarter of 2022, Cenovus recognized a revaluation gain of $549 million as part of the Sunrise Acquisition. As required by IFRS 3, "*Business Combinations*", 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 3 of the interim Consolidated Financial Statements for further details.

Re-measurement of Contingent Payments

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 in a quarter exceeds $52.00 per barrel. The maximum cumulative variable payment is $600 million. Refer to Note 15 of the interim Consolidated Financial Statements for further details.

The contingent payment is accounted for as a financial option with changes in fair value recognized in net earnings (loss). As at September 30, 2023, the fair value of the variable payment was estimated to be $295 million, resulting in non-cash re-measurement losses of $67 million and $83 million in the three and nine months ended September 30, 2023, respectively (three months ended September 30, 2022 – gains of $109 million).

In the nine months ended September 30, 2023, we paid $207 million under this agreement. The latest quarterly payment of $92 million was made on October 30, 2023. The payments are recognized in cash from (used in) investing activities with no impact to Adjusted Funds Flow. As of September 30, 2023, average estimated WCS forward pricing for the remaining term of the variable payment is approximately $89.81 per barrel. As at September 30, 2023, the remaining payments are considered current liabilities. The maximum payment over the remaining four quarters of the contract is $301 million.

The contingent payment associated with the transaction with ConocoPhillips related to its 50 percent interest in the FCCL Partnership ended on May 17, 2022, and the final payment was made in July 2022.

(Gain) Loss on Divestiture of Assets

We had no material divestitures in the three and nine months ended September 30, 2023. In the three months ended September 30, 2022, we recognized a loss on divestiture of assets of $60 million primarily related to the disposition of our retail fuels network. In the nine months ended September 30, 2022, we recognized a gain on divestiture of assets of $244 million due to the sale of our Tucker and Wembley assets, the divestiture of 12.5 percent of our interest in the White Rose field and satellite extensions, and the retail divestiture.

Other (Income) Loss, Net

In the three and nine months ended September 30, 2023, other income was $22 million and $42 million, respectively (2022 – $59 million and $467 million, respectively). Other income in the first nine months of 2022 was primarily due to insurance proceeds related to the 2018 incidents at the Superior Refinery and in the Atlantic region.

DD&A

DD&A for the three and nine months ended September 30, 2023, was $19 million and $59 million, respectively (2022 – $27 million and $86 million, respectively).

Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2023**	2022	**2023**	2022
Current Tax				
Canada	**484**	187	**941**	1,124
United States	**4**	(185)	**4**	96
Asia Pacific	**68**	64	**152**	173
Other International	**7**	10	**19**	10
Total Current Tax Expense (Recovery)	**563**	76	**1,116**	1,403
Deferred Tax Expense (Recovery)	**(2)**	568	**(416)**	625
	561	644	**700**	2,028

For the nine months ended September 30, 2023, the Company recorded a current tax expense related to operations in all jurisdictions that Cenovus operates. The decline in current income tax expense for the nine months ended September 30, 2023, was due to lower earnings compared with 2022. The effective tax rate in the first nine months of 2023 was 17.2 percent (2022 – 26.4 percent). The lower rate is primarily due to the deferred tax recovery recorded in the first quarter of 2023 related to the step-up in the tax basis on the Toledo Acquisition. Excluding the impact of the Toledo Acquisition, the effective tax rate in 2023 would be consistent with the statutory rate.

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.

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 legislation.

LIQUIDITY AND CAPITAL RESOURCES

Our capital allocation framework enables us to strengthen our balance sheet, provide flexibility in both high and low commodity price environments, and deliver value to shareholders. The 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.

We expect to fund our near-term cash requirements through cash from operating activities, the prudent use of our cash and cash equivalents, and other sources of liquidity. This includes draws on our committed credit facility, draws on our uncommitted demand facilities and other corporate and financial opportunities which provide timely access to funding to supplement cash flow. We remain committed to maintaining our investment grade credit ratings at S&P Global Ratings, Moody's Investor Service, DBRS Morningstar 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.

($ millions)	Three Months Ended September 30, 2023	2022	Nine Months Ended September 30, 2023	2022
Cash From (Used In)				
Operating Activities	**2,738**	4,089	**4,442**	8,433
Investing Activities	**(1,101)**	(690)	**(4,015)**	(1,144)
Net Cash Provided (Used) Before Financing Activities	**1,637**	3,399	**427**	7,289
Financing Activities	**(2,600)**	(3,822)	**(3,674)**	(6,926)
Effect of Foreign Exchange on Cash and Cash Equivalents	**58**	224	**(15)**	258
Increase (Decrease) in Cash and Cash Equivalents	**(905)**	(199)	**(3,262)**	621

As at ($ millions)	September 30, 2023	December 31, 2022
Cash and Cash Equivalents	**1,262**	4,524
Total Debt	**7,238**	8,806

Cash From (Used in) Operating Activities

For the three months ended September 30, 2023, cash from operating activities was $2.7 billion compared with $4.1 billion in the same period in 2022. The decrease was mainly due to changes in non-cash working capital, partially offset by higher Operating Margin. During the three months ended September 30, 2023, the net change in non-cash working capital decreased cash by $641 million primarily due to higher accounts receivable, inventories and higher cash taxes, mainly related to rising commodity pricing. The change was partially offset by higher accounts payable, primarily due to higher crude throughput. During the same period in 2022, the net change in non-cash working capital resulted in an increase in cash from operating activities of $1.2 billion.

For the nine months ended September 30, 2023, cash from operating activities was $4.4 billion (2022 – $8.4 billion). The significant decrease was primarily due to lower Operating Margin and a working capital build. During the nine months ended September 30, 2023, the net change in non-cash working capital decreased cash by $2.1 billion, related primarily to higher commodity pricing and driven largely by the payment of the December 31, 2022, income tax liability of $1.2 billion in the first quarter of 2023.

Cash From (Used in) Investing Activities

Cash used in investing activities increased in the third quarter of 2023 compared with 2022 due to no divestitures in the third quarter of 2023 compared with the sale of our retail fuels network in the third quarter of 2022, higher capital spending in the third quarter of 2023 and a decrease in non-cash working capital. The increase was partially offset by lower acquisition costs in 2023 with the Sunrise Acquisition in the third quarter of 2022.

Cash used in investing activities increased significantly in the first nine months of 2023 compared with 2022. The increase was due to higher capital spending, the closing of the Toledo Acquisition in the first quarter of 2023 and lower proceeds from divestitures as 2022 included the sales of our retail fuels network, Tucker and Wembley assets. The increase was partially offset by the Sunrise Acquisition in the third quarter of 2022. Additionally, non-cash working capital decreased in 2023 primarily due to the Sunrise contingent payment.

Cash From (Used in) Financing Activities

Cash used in financing activities decreased in the third quarter of 2023, largely due to lower purchases of unsecured notes compared with the same period in 2022, partially offset by the payment of the warrant obligation. In the third quarter of 2023, we purchased US$1.0 billion of unsecured notes due between 2029 and 2047 at a discount of $84 million. In the third quarter of 2022, we purchased US$2.2 billion of unsecured notes due between 2025 and 2043 at a discount of $4 million.

Cash used in financing activities decreased in the nine months ended September 30, 2023, compared with the same period in 2022 primarily due to reasons noted above, combined with additional long-term debt purchases in 2022 of $750 million and US$402 million. The decreases were also caused by higher common share purchases through our NCIB in 2022, partially offset by an increase in common share base dividend payments in 2023. In 2023, we paid base dividends of $0.385 per share on our common shares (2022 – $0.245 per share).

In the three months ended September 30, 2023, we issued net short-term borrowings of $14 million (2022 – net payments of $2 million). In the nine months ended September 30, 2023, we made net payments of $101 million on short-term borrowings (2022 – $81 million, net).

Working Capital

Excluding the contingent payment, our adjusted working capital at September 30, 2023, was $3.8 billion (December 31, 2022 – $4.7 billion).

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

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 Cenovus 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2023**	2022	**2023**	2022
Cash From (Used in) Operating Activities	**2,738**	4,089	**4,442**	8,433
(Add) Deduct:				
Settlement of Decommissioning Liabilities	**(68)**	(55)	**(157)**	(101)
Net Change in Non-Cash Working Capital	**(641)**	1,193	**(2,142)**	(98)
Adjusted Funds Flow	**3,447**	2,951	**6,741**	8,632
Capital Investment	**1,025**	866	**3,128**	2,434
Free Funds Flow	**2,422**	2,085	**3,613**	6,198
Add (Deduct):				
Base Dividends Paid on Common Shares	**(264)**	(205)		
Dividends Paid on Preferred Shares	**—**	(9)		
Settlement of Decommissioning Liabilities	**(68)**	(55)		
Principal Repayment of Leases	**(70)**	(78)		
Acquisitions, Net of Cash Acquired	**(32)**	(389)		
Proceeds From Divestitures	**1**	407		
Excess Free Funds Flow	**1,989**	1,756		

Returns to Shareholders Target

Maintaining a strong balance sheet with the resilience to withstand price volatility and capitalize on opportunities throughout the commodity price cycle is a key element of Cenovus's capital allocation framework. We have set an ultimate Net Debt Target of $4 billion, which serves as our floor on Net Debt. 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 commodity pricing cycle. 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.

Share buybacks are 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, if the remainder is greater than $50 million. Where the value of share buybacks in a quarter is greater than or equal to the targeted value of returns, no variable dividend will be paid for that quarter.

On June 30, 2023, our long-term debt was $8.5 billion, resulting in a Net Debt position of $6.4 billion. Therefore, our returns to shareholders target for the three months ended September 30, 2023, was 50 percent of the current quarter's Excess Free Funds Flow of $2.0 billion. As such, our Target Return was $1.0 billion. We made returns to shareholders through share buybacks of $361 million and warrant purchase payments of $600 million. Returns to shareholders were within $50 million of our Target Return, as such no variable dividend was declared for the fourth quarter.

	Three Months Ended		
($ millions)	September 30, 2023	June 30, 2023	March 31, 2023
Excess Free Funds Flow	**1,989**	505	(499)
Target Return	**995**	253	—
Less: Purchase of Common Shares Under NCIBs	**(361)**	(310)	(40)
Less: Payment for Purchase of Warrants	**(600)**	—	—
Amount Available for Variable Dividend	**34**	—	—

At September 30, 2023, our Net Debt position was $6.0 billion and as a result our returns to shareholders target for the three months ended December 31, 2023, will be 50 percent of the fourth quarter's Excess Free Funds Flow.

Short-Term Borrowings

As at September 30, 2023, the Company's proportionate share drawn on the WRB uncommitted demand facilities was US$10 million (C$14 million) (December 31, 2022 – the Company's proportionate share drawn was US$85 million (C$115 million)). There were no direct borrowings on our uncommitted demand facilities as at September 31, 2023, or December 31, 2022.

Long-Term Debt, Including Current Portion

Long-term debt, including the current portion, as at September 30, 2023, was $7.2 billion (December 31, 2022 – $8.7 billion). This includes U.S. dollar denominated unsecured notes of US$3.8 billion, or C$5.1 billion (December 31, 2022 – US$4.8 billion, or C$6.5 billion) and Canadian dollar denominated unsecured notes of $2.0 billion (December 31, 2022 – $2.0 billion). The decrease in long-term debt was primarily due to the third quarter purchase of unsecured notes with an aggregate principal amount of US$1.0 billion at a discount of $84 million.

As at September 30, 2023, 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, 2023:

($ millions)	Maturity	Amount Available
Cash and Cash Equivalents	**n/a**	**1,262**
Committed Credit Facility (1)		
Revolving Credit Facility – Tranche A	**November 10, 2026**	**3,700**
Revolving Credit Facility – Tranche B	**November 10, 2025**	**1,800**
Uncommitted Demand Facilities		
Cenovus Energy Inc. (2)	**n/a**	**1,082**
WRB (3)	**n/a**	**291**

(1) No amounts were drawn on the committed credit facility as at September 30, 2023 (December 31, 2022 - $nil).
(2) Our uncommitted demand facilities include $1.7 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 at September 30, 2023, there were outstanding letters of credit aggregating to $353 million (December 31, 2022 – $490 million) and no direct borrowings (December 31, 2022 – $nil).
(3) Represents Cenovus's proportionate share of US$225 million available to cover short-term working capital requirements. As at September 30, 2023, US$10 million (C$14 million) of this capacity was drawn (December 31, 2022 – US$85 million (C$115 million)).

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.

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. We plan to renew the base shelf prospectus that will expire in November 2023. As at September 30, 2023, US$4.7 billion remained available under the base shelf prospectus for permitted offerings (December 31, 2022 – 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 the Net Debt to Capitalization Ratio, Net Debt to Adjusted Funds Flow Ratio and Net Debt to Adjusted EBITDA Ratio. Refer to Note 13 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 Shareholders 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 used in the Net Debt to Adjusted EBITDA Ratio, as net earnings (loss) before finance costs, net of capitalized interest, interest income, income tax expense (recovery), DD&A, E&E asset write-downs, goodwill impairments, (income) loss from equity-accounted affiliates, unrealized (gain) loss on risk management, net foreign exchange (gain) loss, revaluation (gain) loss, re-measurement of contingent payments, (gain) loss on divestiture of assets, and net other (income) loss calculated on a trailing twelve-month basis. These ratios are used to steward our overall debt position and are measures of our overall financial strength.

As at	**September 30, 2023**	December 31, 2022
Net Debt to Capitalization Ratio (percent)	**17**	13
Net Debt to Adjusted Funds Flow Ratio (times)	**0.7**	0.4
Net Debt to Adjusted EBITDA Ratio (times)	**0.6**	0.3

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.

Our Net Debt to Capitalization Ratio as at September 30, 2023, increased compared with December 31, 2022, primarily due to higher Net Debt.

Our Net Debt to Adjusted Funds Flow Ratio and Net Debt to Adjusted EBITDA Ratio as at September 30, 2023, increased compared with December 31, 2022, as a result of higher Net Debt and lower Operating Margin. 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

Our common shares and Cenovus Warrants are listed on the Toronto Stock Exchange ("TSX") and New York Stock Exchange ("NYSE"). Our cumulative redeemable preferred shares series 1, 2, 3, 5 and 7 are listed on the TSX.

As at September 30, 2023, there were approximately 1,885.6 million common shares outstanding (December 31, 2022 – 1,909.2 million common shares) and 36 million preferred shares outstanding (December 31, 2022 – 36 million preferred shares). Refer to Note 18 of the interim Consolidated Financial Statements for further details.

Cenovus has an NCIB program to purchase up to 136.7 million common shares during the period from November 9, 2022, to November 8, 2023.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2023	2022	**2023**	2022
Common Shares Purchased Under NCIBs (millions of common shares) (1)	**14**	29.1	**29**	96.9
Weighted Average Price per Common Share ($)	**26.18**	22.60	**24.19**	22.10
Purchase of Common Shares Under NCIB ($ millions)	**(361)**	(659)	**(711)**	(2,143)

(1) Common shares were subsequently cancelled after purchase.

From October 1, 2023, to October 30, 2023, the Company purchased an additional 3.3 million common shares for $89 million. As at October 30, 2023, the Company can further purchase up to 92.5 million common shares under the existing NCIB. The current NCIB will expire on November 8, 2023.

On November 1, 2023, we received approval from the Board of Directors to apply to the TSX for an additional NCIB program. Subject to acceptance by the TSX, the Company will be able to purchase up to approximately 133 million common shares for a period of twelve months.

As at September 30, 2023, there were approximately 7.9 million Cenovus Warrants outstanding (December 31, 2022 – 55.7 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 18 of the interim Consolidated Financial Statements for further details.

On June 14, 2023, we purchased and cancelled 45.5 million outstanding Cenovus Warrants. The price for each warrant purchased represented a price of $22.18 per common share, less the warrant exercise price of $6.54 per common share, for a total of $711 million. We also recorded $2 million of transaction costs. This purchase represented 84 percent of Cenovus's outstanding warrants. During the three months ended September 30, 2023, we paid $600 million related to the purchased warrants. The remaining amount must be paid by January 5, 2024.

Refer to Note 20 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 30, 2023	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**1,883,596**	**n/a**
Cenovus Warrants	**7,917**	**n/a**
Series 1 First Preferred Shares	**10,740**	**n/a**
Series 2 First Preferred Shares	**1,260**	**n/a**
Series 3 First Preferred Shares	**10,000**	**n/a**
Series 5 First Preferred Shares	**8,000**	**n/a**
Series 7 First Preferred Shares	**6,000**	**n/a**
Stock Options	**12,922**	**7,646**
Other Stock-Based Compensation Plans	**19,048**	**1,662**

Common Share Dividends

In the third quarter of 2023, we paid base dividends of $264 million or $0.140 per common share (2022 – $205 million or $0.105 per common share). In the first nine months of 2023, we paid base dividends of $729 million or $0.385 per common share (2022 – $481 million or $0.245 per common share). No variable dividend was declared for the third quarter of 2023.

The Board declared a fourth quarter base dividend of $0.140 per common share, payable on December 29, 2023, to common shareholders of record as at December 15, 2023.

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

Cumulative Redeemable Preferred Share Dividends

In the three and nine months ended September 30, 2023, dividends of $nil and $27 million, respectively, were paid on the series 1, 2, 3, 5 and 7 preferred shares (2022 – $9 million and $26 million, respectively). The declaration of preferred share dividends is at the sole discretion of the 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 2, 2024, to preferred shareholders of record as at December 15, 2023.

Capital Investment Decisions

Our 2023 capital program is forecast to be between $4.0 billion and $4.5 billion, including approximately $2.8 billion of sustaining capital and between $1.2 billion to $1.7 billion of optimization and growth capital. Our Future Capital Investment is focused on disciplined capital allocation, investment plans to progress opportunities across our integrated portfolio, cost control and positioning the Company for continued growth in shareholder returns. We expect our annual upstream production to average between 775 thousand BOE per day and 795 thousand BOE per day and our downstream crude oil unit throughput average between 580 thousand barrels per day to 610 thousand barrels per day in 2023. Our guidance as updated on July 26, 2023, is available at our website at cenovus.com.

Contractual Obligations and Commitments

We have obligations for goods and services entered into in the normal course of business. Obligations that have original maturities of less than one year are excluded. For further information, see Note 25 to the interim Consolidated Financial Statements.

Our total commitments were $24.7 billion as at September 30, 2023 (December 31, 2022 – $33.0 billion), of which $20.2 billion of our commitments are for various transportation and storage commitments and $1.2 billion are for product purchase commitments. Transportation commitments include $9.1 billion that are subject to regulatory approval or were 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. Total commitments decreased from December 31, 2022, primarily due to the reduction in the contract terms of certain product purchase contracts.

As at September 30, 2023, our total commitments included commitments with HMLP of $2.1 billion related to long-term transportation and storage services.

As at September 30, 2023, outstanding letters of credit issued as security for performance under certain contracts totaled $353 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

Cenovus holds a 35 percent interest in HMLP. As the operator of the assets held by HMLP, we provide management services for which we recover shared service costs in accordance with our profit sharing agreement. 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, 2023, we charged HMLP $49 million and $112 million, respectively, for construction and management services (three and nine months ended September 30, 2022 – $56 million and $133 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, 2023, we incurred costs of $67 million and $205 million, respectively, for the use of HMLP's pipeline systems, as well as for transportation and storage services (three and nine months ended September 30, 2022 – $64 million and $197 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 2022 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, without limitation, 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, repurchase our shares, pay dividends to our shareholders, and fulfill our obligations (including debt servicing requirements) and may materially affect the market price of our securities.

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 material accounting policies are reviewed annually by the Audit Committee of the Board. Further details on the basis of preparation and our material accounting policies can be found in the notes to the Consolidated Financial Statements for the year ended December 31, 2022.

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 critical judgments used in applying accounting policies and key sources of estimation uncertainty can be found in the notes to the Consolidated Financial Statements for the year ended December 31, 2022. There were no changes to our critical judgments used in applying accounting policies and key sources of measurement uncertainty during the nine months ended September 30, 2023.

New Accounting Standards and Interpretations Not Yet Adopted

There are new accounting standards, amendments to accounting standards and interpretations that were effective for annual periods beginning on or after January 1, 2023, 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, 2023, 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, 2023. 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, 2023.

On February 28, 2023, Cenovus closed the Toledo Acquisition. As permitted by and in accordance with, National Instrument 52-109, *"Certification of Disclosure in Issuers' Annual and Interim Filings"*, and guidance issued by the U.S. Securities and Exchange Commission, Management has limited the scope and design of ICFR and DC&P to exclude the controls, policies and procedures in respect of the business acquired from bp. Such scope limitation is primarily due to the time required for Management to assess the ICFR and DC&P relating to the business acquired from bp in a manner consistent with our other operations. Further integration will take place throughout the remainder of the year as processes and systems align.

Assets acquired from bp represented approximately one percent of Cenovus's total assets at September 30, 2023. Revenues attributable to assets acquired from bp were less than seven percent of Cenovus's total revenues for the three and nine months ended September 30, 2023. Operating expenses attributable to assets acquired from bp were approximately five percent of Cenovus's total operating expenses for the three and nine months ended September 30, 2023.

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 are 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 "aim", "anticipate", "believe", "capacity", "commit", "continue", "could", "estimate", "expect", "focus", "forecast", "may", "objective", "opportunities", "plan", "position", "prioritize", "strive", "target", and "will", or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: shareholder value and returns; cost structure; margins; safety performance; sustainability and sustainability leadership; using the Company's integrated network of assets to maximize value; delivering on our strategy; returning incremental value to shareholders through share buybacks and/or variable dividends in accordance with the capital allocation framework; GHG emissions; interest expense; infrastructure; operating and capital costs; capital investment, allocation, and structure; capital discipline; Free Funds Flow generation; resiliency; Excess Free Funds Flow allocation; balance sheet management and strength; flexibility in both high and low commodity price environments; funding near-term cash requirements; managing capital structure; dividends of any kind; share repurchases under the NCIB and renewal of same; full payment of the aggregate warrant purchase price; reinvestment in the business; diversifying the portfolio; deleveraging; near-term funding requirements; meeting payment obligations; maintaining credit ratings; debt levels; Net Debt; Net Debt to Adjusted Funds Flow Ratio; Net Debt to Adjusted EBITDA Ratio; adjusting capital and operating spending; drawing down credit facilities; repaying existing debt; adjusting dividends; purchasing Cenovus common shares; issuing new debt; issuing new shares; renewing our Base Shelf prospectus; maintaining liquidity; capital expenditures; production and production rates; crude oil unit throughput or throughput; consistent and reliable operations at all operated assets; operating performance; liabilities from legal proceedings; cash flow; financial results; variable payments; provision for income taxes; financial resilience; capturing value; monitoring market fundamentals; mitigating the impact of crude oil and refined product differentials; plans to achieve targets for the Company’s five ESG focus areas: climate and GHG emissions, water stewardship, biodiversity, indigenous reconciliation, inclusion and diversity; the focus of our 2023 budget; business and asset integration; integrating the Toledo and Lima refineries; optimizing run rates at the Company’s refineries; completion of the planned turnaround at the Borger Refinery; pad construction and first steam in the Ipiatik area at Foster Creek; adding additional bitumen reserves to the Foster Creek plant through the acquisition of the Ipiatik area; full ramp-up of the Superior Refinery; integration of the Toledo Refinery; transportation and storage commitments; commissioning the Terra Nova floating production, storage and offloading unit to resume production at the Terra Nova Field in the fourth quarter of 2023; progressing the West White Rose project to deliver first oil in 2026; Indonesia; and the Company’s outlook for commodities and the Canadian dollar and the influences and effects 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 bitumen, crude 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 acquisitions; the accuracy of any assessments undertaken in connection with acquisitions; forecast production and crude oil unit throughput volumes and timing thereof; 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 bitumen, 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 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; 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 Canada; market and business conditions; forecast inflation and other assumptions inherent in the Company’s 2023 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.

2023 guidance dated July 26, 2023, and available on cenovus.com, assumes: Brent prices of US$76.00 per barrel, WTI prices of US$71.00 per barrel; WCS of US$54.50 per barrel; Differential WTI-WCS of US$16.50 per barrel; AECO natural gas prices of $2.90 per Mcf; Chicago 3-2-1 crack spread of US$26.50 per barrel; and an exchange rate of $0.75 US$/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; the Company's ability to realize the anticipated benefits of acquisitions in a timely manner or at all; unforeseen or underestimated liabilities associated with 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 being 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 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 Canada; 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 at facilities operated by our partners or third parties, such as blowouts, fires, explosions, railcar incidents or derailments, aviation incidents, iceberg collisions, 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, adverse sea conditions, extreme weather events, natural disasters, acts of activism, 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 and diverse 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 most recently filed Annual 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 sedarplus.ca, 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 and definitions are used in this document:

Crude Oil		Natural Gas		Other	
bbl	barrel	Mcf	thousand cubic feet	BOE	barrel of oil equivalent
mbbls/d	thousand barrels per day	MMcf	million cubic feet	MBOE	thousand barrels of oil equivalent
WTI	West Texas Intermediate	MMcf/d	million cubic feet per day	MBOE/d	thousand barrels of oil equivalent per day
WCS	Western Canadian Select			OPEC	Organization of Petroleum Exporting Countries
				OPEC+	OPEC and a group of 10 non-OPEC members
				GHG	Greenhouse Gas
				AECO	Alberta Energy Company
				NCIB	Normal Course Issuer Bid
				NYMEX	New York Mercantile Exchange
				SAGD	steam-assisted gravity drainage
				USGC	U.S. Gulf Coast

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, Adjusted Funds Flow, Adjusted Funds Flow Per Share – Basic, Adjusted Funds Flow Per Share – Diluted, Free Funds Flow, Excess Free Funds Flow, Gross Margin, Refining Margin, Unit Operating Expense, Per Unit DD&A and Netbacks (including the total netbacks per BOE).

These measures may not be comparable to similar measures presented by other issuers. These measures are 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. Refer to the Specified Financial Measures Advisory of our 2022 annual MD&A for reconciliations of Operating Margin, Adjusted Funds Flow, Free Funds Flow, Excess Free Funds Flow for quarters in 2022 and 2021 not found below.

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 expenses, 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,					
	2023	2022	**2023**	2022	**2023**	2022
($ millions)	**Upstream** [(1)]		**Downstream** [(1)]		**Total**	
Revenues						
Gross Sales [(2)]	**8,783**	10,250	**9,658**	10,873	**18,441**	21,123
Less: Royalties	**1,135**	1,226	**—**	—	**1,135**	1,226
	7,648	9,024	**9,658**	10,873	**17,306**	19,897
Expenses						
Purchased Product [(2)]	**900**	2,383	**7,947**	9,680	**8,847**	12,063
Transportation and Blending [(2)]	**2,397**	2,826	**—**	—	**2,397**	2,826
Operating	**914**	915	**778**	780	**1,692**	1,695
Realized (Gain) Loss on Risk Management	**(10)**	51	**11**	(77)	**1**	(26)
Operating Margin	**3,447**	2,849	**922**	490	**4,369**	3,339

	Nine Months Ended September 30,					
	2023	2022	**2023**	2022	**2023**	2022
($ millions)	**Upstream** [(1)]		**Downstream** [(1)]		**Total**	
Revenues						
Gross Sales [(2)]	**23,285**	32,891	**24,222**	29,708	**47,507**	62,599
Less: Royalties	**2,368**	3,993	**—**	—	**2,368**	3,993
	20,917	28,898	**24,222**	29,708	**45,139**	58,606
Expenses						
Purchased Product [(2)]	**2,489**	5,662	**20,385**	25,416	**22,874**	31,078
Transportation and Blending [(2)]	**8,194**	9,317	**—**	—	**8,194**	9,317
Operating	**2,826**	2,834	**2,375**	2,291	**5,201**	5,125
Realized (Gain) Loss on Risk Management	**(7)**	1,485	**6**	120	**(1)**	1,605
Operating Margin	**7,415**	9,600	**1,456**	1,881	**8,871**	11,481

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Comparative periods reflect certain revisions. See Note 26 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

($ millions)	Three Months Ended March 31, 2023 [1] Upstream	Downstream	Total	Three Months Ended June 30, 2023 [1] Upstream	Downstream	Total	Six Months Ended June 30, 2023 [1] Upstream	Downstream	Total
Revenues									
Gross Sales	7,217	7,137	14,354	7,285	7,427	14,712	14,502	14,564	29,066
Less: Royalties	596	—	596	637	—	637	1,233	—	1,233
	6,621	7,137	13,758	6,648	7,427	14,075	13,269	14,564	27,833
Expenses									
Purchased Product	838	5,991	6,829	751	6,447	7,198	1,589	12,438	14,027
Transportation and Blending	3,027	—	3,027	2,770	—	2,770	5,797	—	5,797
Operating	1,029	754	1,783	883	843	1,726	1,912	1,597	3,509
Realized (Gain) Loss on Risk Management	16	1	17	(13)	(6)	(19)	3	(5)	(2)
Operating Margin	1,711	391	2,102	2,257	143	2,400	3,968	534	4,502

	2022													
	Upstream							**Downstream**						
	Three Months Ended				Year-to-Date			Three Months Ended				Year-to-Date		
($ millions)	Q1	Q2	Q3	Q4	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q2	Q3	Q4
Revenues														
Gross Sales [1]	10,922	11,719	10,250	8,251	22,641	32,891	41,142	8,116	10,719	10,873	8,302	18,835	29,708	38,010
Less: Royalties	1,185	1,582	1,226	875	2,767	3,993	4,868	—	—	—	—	—	—	—
	9,737	10,137	9,024	7,376	19,874	28,898	36,274	8,116	10,719	10,873	8,302	18,835	29,708	38,010
Expenses														
Purchased Product [1]	1,818	1,461	2,383	1,079	3,279	5,662	6,741	6,817	8,919	9,680	6,993	15,736	25,416	32,409
Transportation and Blending [1]	3,219	3,272	2,826	2,984	6,491	9,317	12,301	—	—	—	—	—	—	—
Operating	909	1,010	915	955	1,919	2,834	3,789	645	866	780	759	1,511	2,291	3,050
Realized (Gain) Loss on Risk Management	871	563	51	134	1,434	1,485	1,619	110	87	(77)	(8)	197	120	112
Operating Margin	2,920	3,831	2,849	2,224	6,751	9,600	11,824	544	847	490	558	1,391	1,881	2,439

	2022						
	Total						
	Three Months Ended				Year-to-Date		
($ millions)	Q1	Q2	Q3	Q4	Q2	Q3	Q4
Revenues							
Gross Sales [1]	19,038	22,438	21,123	16,553	41,476	62,599	79,152
Less: Royalties	1,185	1,582	1,226	875	2,767	3,993	4,868
	17,853	20,856	19,897	15,678	38,709	58,606	74,284
Expenses							
Purchased Product [1]	8,635	10,380	12,063	8,072	19,015	31,078	39,150
Transportation and Blending [1]	3,219	3,272	2,826	2,984	6,491	9,317	12,301
Operating	1,554	1,876	1,695	1,714	3,430	5,125	6,839
Realized (Gain) Loss on Risk Management	981	650	(26)	126	1,631	1,605	1,731
Operating Margin	3,464	4,678	3,339	2,782	8,142	11,481	14,263

(1) *Comparative periods reflect certain revisions. See Note 26 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.*

	2021							
	Upstream				Downstream			
	Three Months Ended		Year-to-Date		Three Months Ended		Year-to-Date	
($ millions)	Q3	Q4	Q3	Q4	Q3	Q4	Q3	Q4
Revenues								
Gross Sales [1]	7,375	8,258	19,667	27,925	7,422	8,010	18,248	26,258
Less: Royalties	733	815	1,639	2,454	—	—	—	—
	6,642	7,443	18,028	25,471	7,422	8,010	18,248	26,258
Expenses								
Purchased Product [1]	1,074	1,198	2,861	4,059	6,600	7,223	15,888	23,111
Transportation and Blending [1]	2,158	2,620	6,175	8,795	—	—	—	—
Operating	800	865	2,376	3,241	537	689	1,569	2,258
Realized (Gain) Loss on Risk Management	168	202	586	788	17	56	48	104
Operating Margin	2,442	2,558	6,030	8,588	268	42	743	785

	2021			
	Total			
	Three Months Ended		Year-to-Date	
($ millions)	Q3	Q4	Q3	Q4
Revenues				
Gross Sales [1]	14,797	16,268	37,915	54,183
Less: Royalties	733	815	1,639	2,454
	14,064	15,453	36,276	51,729
Expenses				
Purchased Product [1]	7,674	8,421	18,749	27,170
Transportation and Blending [1]	2,158	2,620	6,175	8,795
Operating	1,337	1,554	3,945	5,499
Realized (Gain) Loss on Risk Management	185	258	634	892
Operating Margin	2,710	2,600	6,773	9,373

Operating Margin by Asset

	Three Months Ended September 30, 2023			**Nine Months Ended September 30, 2023**		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore [1]**	**Atlantic**	**Asia Pacific**	**Offshore [1]**
Revenues						
Gross Sales	**78**	**324**	**402**	**232**	**871**	**1,103**
Less: Royalties	**2**	**24**	**26**	**11**	**54**	**65**
	76	**300**	**376**	**221**	**817**	**1,038**
Expenses						
Transportation and Blending	**—**	**—**	**—**	**9**	**—**	**9**
Operating	**47**	**29**	**76**	**190**	**91**	**281**
Operating Margin	**29**	**271**	**300**	**22**	**726**	**748**

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

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

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

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, in total and on a per-share basis. 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, income tax receivable, inventories (excluding non-cash inventory write-downs and reversals), accounts payable and accrued liabilities and income tax payable. Adjusted Funds Flow Per Share – Basic is defined as Adjusted Funds Flow divided by the basic weighted average number of shares. Adjusted Funds Flow Per Share – Diluted is defined as Adjusted Funds Flow divided by the diluted weighted average number of shares.

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.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
($ millions)	**2023**	2022	**2023**	2022
Cash From (Used in) Operating Activities	**2,738**	4,089	**4,442**	8,433
(Add) Deduct:				
Settlement of Decommissioning Liabilities	**(68)**	(55)	**(157)**	(101)
Net Change in Non-Cash Working Capital	**(641)**	1,193	**(2,142)**	(98)
Adjusted Funds Flow	**3,447**	2,951	**6,741**	8,632
Capital Investment	**1,025**	866	**3,128**	2,434
Free Funds Flow	**2,422**	2,085	**3,613**	6,198
Add (Deduct):				
Base Dividends Paid on Common Shares	**(264)**	(205)		
Dividends Paid on Preferred Shares	**—**	(9)		
Settlement of Decommissioning Liabilities	**(68)**	(55)		
Principal Repayment of Leases	**(70)**	(78)		
Acquisitions, Net of Cash Acquired	**(32)**	(389)		
Proceeds From Divestitures	**1**	407		
Excess Free Funds Flow	**1,989**	1,756		

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 unit 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 from our refineries and upgrader divided by barrels of crude oil unit throughput.

Canadian Manufacturing

($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Manufacturing [2]
	Three Months Ended September 30, 2023				
	Basis of Refining Margin Calculation				
Revenues	**1,573**	**325**	**1,898**	**(93)**	**1,805**
Purchased Product	**1,357**	**250**	**1,607**	**(127)**	**1,480**
Gross Margin	**216**	**75**	**291**	**34**	**325**

	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
	Operating Statistics		
Heavy Crude Oil Unit Throughput (Mbbls/d)	**80.6**	**27.8**	**108.4**
Refining Margin ($/bbl)	**29.12**	**29.30**	**29.17**

(1) Includes ethanol operations and crude-by-rail operations.
(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, 2022				
	Basis of Refining Margin Calculation				
Revenues	998	387	**1,385**	783	**2,168**
Purchased Product	747	286	**1,033**	717	**1,750**
Gross Margin	251	101	**352**	66	**418**

	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
	Operating Statistics		
Heavy Crude Oil Unit Throughput (Mbbls/d)	**71.3**	**27.2**	**98.5**
Refining Margin ($/bbl)	**38.33**	**40.33**	**38.88**

(1) Includes ethanol operations, crude-by-rail operations, and the retail and commercial fuels business.
(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, 2023				
	Basis of Refining Margin Calculation				
Revenues	**4,177**	**739**	**4,916**	**(240)**	**4,676**
Purchased Product	**3,484**	**511**	**3,995**	**(339)**	**3,656**
Gross Margin	**693**	**228**	**921**	**99**	**1,020**

	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
	Operating Statistics		
Heavy Crude Oil Unit Throughput (Mbbls/d)	**72.9**	**27.9**	**100.8**
Refining Margin ($/bbl)	**34.82**	**29.98**	**33.48**

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

	Nine Months Ended September 30, 2022				
	Basis of Refining Margin Calculation				
($ millions)	**Lloydminster Upgrader**	**Lloydminster Refinery**	**Lloydminster Upgrader and Lloydminster Refinery Total**	**Other [1]**	**Total Canadian Manufacturing [2]**
Revenues	2,917	816	**3,733**	2,287	**6,020**
Purchased Product	2,344	639	**2,983**	2,082	**5,065**
Gross Margin	573	177	**750**	205	**955**

	Operating Statistics		
	Lloydminster Upgrader	**Lloydminster Refinery**	**Lloydminster Upgrader and Lloydminster Refinery Total**
Heavy Crude Oil Unit Throughput (Mbbls/d)	**68.8**	**23.7**	**92.5**
Refining Margin ($/bbl)	**30.49**	**27.38**	**29.69**

(1) Includes ethanol operations, crude-by-rail operations, and the retail and commercial fuels business.
(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)	**2023**	2022	**2023**	2022
Revenues [1]	**7,853**	8,705	**19,546**	23,688
Purchased Product [1]	**6,467**	7,930	**16,729**	20,351
Gross Margin	**1,386**	775	**2,817**	3,337
Crude Oil Unit Throughput (Mbbls/d)	**555.9**	435.0	**453.3**	405.3
Refining Margin ($/bbl)	**27.10**	18.98	**22.77**	29.94

(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 in our upstream segments. We define Per Unit DD&A as the sum of upstream depletion on producing crude oil and natural gas properties and the associated asset retirement costs 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 and exclude risk management activities. The sales price, transportation and blending expense, 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.

Oil Sands

	Basis of Netback Calculation						
Three Months Ended September 30, 2023 ($ millions)	Foster Creek	Christina Lake	Sunrise	Other Oil Sands [1]	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
Gross Sales	1,798	1,936	456	998	5,188	1	**5,189**
Royalties	375	603	22	81	1,081	1	**1,082**
Purchased Product	—	—	—	—	—	—	**—**
Transportation and Blending	192	122	58	36	408	—	**408**
Operating	198	197	75	218	688	2	**690**
Netback	1,033	1,014	301	663	3,011	(2)	**3,009**
Realized (Gain) Loss on Risk Management							**(6)**
Operating Margin							**3,015**

	Basis of Netback Calculation	Adjustments			
Three Months Ended September 30, 2023 ($ millions)	Total Oil Sands	Condensate	Third-party Sourced	Other [2]	Total Oil Sands [3]
Gross Sales	**5,189**	1,889	398	95	**7,571**
Royalties	**1,082**	—	—	—	**1,082**
Purchased Product	**—**	—	398	64	**462**
Transportation and Blending	**408**	1,889	—	27	**2,324**
Operating	**690**	—	—	(2)	**688**
Netback	**3,009**	—	—	6	**3,015**
Realized (Gain) Loss on Risk Management	**(6)**	—	—	—	**(6)**
Operating Margin	**3,015**	—	—	6	**3,021**

	Basis of Netback Calculation						
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
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**

	Basis of Netback Calculation	Adjustments			
Three Months Ended September 30, 2022 ($ millions)	Total Oil Sands	Condensate	Third-party Sourced [4]	Other [2]	Total Oil Sands [3] [4]
Gross Sales	**4,484**	2,333	1,868	79	**8,764**
Royalties	**1,130**	—	—	6	**1,136**
Purchased Product	**—**	—	1,868	51	**1,919**
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**

(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) Comparative periods reflect certain revisions. See Note 26 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Nine Months Ended September 30, 2023 ($ 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	4,035	4,401	941	2,430	11,807	6	**11,813**
Royalties	783	1,190	42	199	2,214	4	**2,218**
Purchased Product	—	—	—	—	—	—	**—**
Transportation and Blending	619	411	157	114	1,301	—	**1,301**
Operating	608	562	229	681	2,080	8	**2,088**
Netback	2,025	2,238	513	1,436	6,212	(6)	**6,206**
Realized (Gain) Loss on Risk Management							**(7)**
Operating Margin							**6,213**

Nine Months Ended September 30, 2023 ($ millions)	Basis of Netback Calculation Total Oil Sands	Adjustments Condensate	Third-party Sourced	Other (2)	Total Oil Sands (3)
Gross Sales	**11,813**	6,578	1,043	281	**19,715**
Royalties	**2,218**	—	—	—	**2,218**
Purchased Product	**—**	—	1,043	188	**1,231**
Transportation and Blending	**1,301**	6,578	—	86	**7,965**
Operating	**2,088**	—	—	13	**2,101**
Netback	**6,206**	—	—	(6)	**6,200**
Realized (Gain) Loss on Risk Management	**(7)**	—	—	—	**(7)**
Operating Margin	**6,213**	—	—	(6)	**6,207**

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 Total Oil Sands	Adjustments Condensate	Third-party Sourced (4)	Other (2)	Total Oil Sands (3) (4)
Gross Sales	**15,903**	7,892	3,987	248	**28,030**
Royalties	**3,698**	—	—	11	**3,709**
Purchased Product	**—**	—	3,987	215	**4,202**
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**

(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) Comparative periods reflect certain revisions. See Note 26 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Conventional

Three Months Ended September 30, 2023 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	**330**	438	42	**810**
Royalties	**26**	—	1	**27**
Purchased Product	**—**	438	—	**438**
Transportation and Blending	**44**	—	29	**73**
Operating	**144**	—	6	**150**
Netback	**116**	—	6	**122**
Realized (Gain) Loss on Risk Management	**(4)**	—	—	**(4)**
Operating Margin	**120**	—	6	**126**

Three Months Ended September 30, 2022 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced [3]	Other [1]	Conventional [2] [3]
Gross Sales	**512**	464	60	**1,036**
Royalties	**68**	—	—	**68**
Purchased Product	**—**	464	—	**464**
Transportation and Blending	**29**	—	35	**64**
Operating	**137**	—	4	**141**
Netback	**278**	—	21	**299**
Realized (Gain) Loss on Risk Management	**9**	—	—	**9**
Operating Margin	**269**	—	21	**290**

Nine Months Ended September 30, 2023 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	**1,059**	1,258	150	**2,467**
Royalties	**85**	—	—	**85**
Purchased Product	**—**	1,258	—	**1,258**
Transportation and Blending	**128**	—	92	**220**
Operating	**429**	—	15	**444**
Netback	**417**	—	43	**460**
Realized (Gain) Loss on Risk Management	**—**	—	—	**—**
Operating Margin	**417**	—	43	**460**

Nine Months Ended September 30, 2022 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced [3]	Other [1]	Conventional [2] [3]
Gross Sales	**1,683**	1,460	143	**3,286**
Royalties	**228**	—	—	**228**
Purchased Product	**—**	1,460	—	**1,460**
Transportation and Blending	**100**	—	91	**191**
Operating	**385**	—	18	**403**
Netback	**970**	—	34	**1,004**
Realized (Gain) Loss on Risk Management	**9**	8	—	**17**
Operating Margin	**961**	(8)	34	**987**

(1) Reflects Operating Margin from processing facilities.
(2) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.
(3) Comparative periods reflect certain revisions. See Note 26 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Offshore

Three Months Ended September 30, 2023 ($ millions)	Basis of Netback Calculation Atlantic	China	Indonesia [1]	Total Asia Pacific	Total Offshore	Adjustments Equity Adjustment [1]	Other [2]	Total Offshore [3]
Gross Sales	78	324	74	**398**	**476**	(74)	—	**402**
Royalties	2	24	15	**39**	**41**	(15)	—	**26**
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	—	—	—	**—**	**—**	—	—	**—**
Operating	47	27	15	**42**	**89**	(12)	(1)	**76**
Netback	29	273	44	**317**	**346**	(47)	1	**300**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**346**	(47)	1	**300**

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

Nine Months Ended September 30, 2023 ($ millions)	Basis of Netback Calculation Atlantic	China	Indonesia [1]	Total Asia Pacific	Total Offshore	Adjustments Equity Adjustment [1]	Other [2]	Total Offshore [3]
Gross Sales	232	871	226	**1,097**	**1,329**	(226)	—	**1,103**
Royalties	11	54	56	**110**	**121**	(56)	—	**65**
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	9	—	—	**—**	**9**	—	—	**9**
Operating	168	82	41	**123**	**291**	(32)	22	**281**
Netback	44	735	129	**864**	**908**	(138)	(22)	**748**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**908**	(138)	(22)	**748**

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

(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 West White Rose project expenses.
(3) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Upstream Sales Volumes [(1)]

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(MBOE/d)	**2023**	2022	**2023**	2022
Oil Sands				
Foster Creek	**197.6**	180.7	**185.6**	190.9
Christina Lake	**229.4**	247.2	**232.9**	247.8
Sunrise	**51.2**	29.7	**46.1**	26.3
Other Oil Sands	**119.0**	120.4	**119.5**	118.8
Total Oil Sands	**597.2**	578.0	**584.1**	583.8
Conventional	**127.2**	126.2	**118.5**	128.0
Sales Before Internal Consumption	**724.4**	704.2	**702.6**	711.8
Less: Internal Consumption [(2)]	**(87.9)**	(80.7)	**(88.5)**	(84.3)
Sales After Internal Consumption	**636.5**	623.5	**614.1**	627.5
Offshore				
Atlantic	**7.8**	7.8	**7.8**	12.6
Asia Pacific				
China	**43.8**	45.4	**39.4**	48.6
Indonesia	**13.7**	10.1	**14.1**	9.7
Total Asia Pacific	**57.5**	55.5	**53.5**	58.3
Total Offshore	**65.3**	63.3	**61.3**	70.9
Total Sales Volumes	**701.8**	686.8	**675.4**	698.4

(1) Sales volumes exclude the impact of purchased condensate.
(2) Represents natural gas volumes produced by the Oil Sands and Conventional segment used for internal consumption by the Oil Sands segment.

Netbacks for the three months ended March 31, 2023, June 30, 2023 and December 31, 2022 and the twelve months ended December 31, 2022 were revised below. Comparative periods reflect certain reclassifications. See Note 26 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Oil Sands

	Basis of Netback Calculation	Adjustments			
Three Months Ended March 31, 2023 ($ millions)	**Total Oil Sands**	**Condensate**	**Third-party Sourced**	**Other**	**Total Oil Sands**
Gross Sales	**2,888**	2,445	294	80	**5,707**
Royalties	**516**	—	—	—	**516**
Purchased Product	**—**		294	61	**355**
Transportation and Blending	**470**	2,445	—	26	**2,941**
Operating	**729**	—	—	8	**737**
Netback	**1,173**	—	—	(15)	**1,158**
Realized (Gain) Loss on Risk Management	**7**	—	—	1	**8**
Operating Margin	**1,166**	—	—	(16)	**1,150**

	Basis of Netback Calculation	Adjustments			
Three Months Ended June 30, 2023 ($ millions)	**Total Oil Sands**	**Condensate**	**Third-party Sourced**	**Other**	**Total Oil Sands**
Gross Sales	**3,736**	2,244	351	106	**6,437**
Royalties	**621**	—	—	(1)	**620**
Purchased Product	**—**	—	351	63	**414**
Transportation and Blending	**424**	2,244	—	32	**2,700**
Operating	**669**	—	—	7	**676**
Netback	**2,022**	—	—	5	**2,027**
Realized (Gain) Loss on Risk Management	**(8)**	—	—	(1)	**(9)**
Operating Margin	**2,030**	—	—	6	**2,036**

	Basis of Netback Calculation	Adjustments			
Three Months Ended December 31, 2022 ($ millions)	**Total Oil Sands**	**Condensate**	**Third-party Sourced**	**Other**	**Total Oil Sands**
Gross Sales	**3,706**	2,415	422	110	**6,653**
Royalties	**784**	—	—	—	**784**
Purchased Product	**—**	—	422	94	**516**
Transportation and Blending	**493**	2,415	—	14	**2,922**
Operating	**735**	—	—	(2)	**733**
Netback	**1,694**	—	—	4	**1,698**
Realized (Gain) Loss on Risk Management	**59**	—	—	—	**59**
Operating Margin	**1,635**	—	—	4	**1,639**

	Basis of Netback Calculation	Adjustments			
Twelve Months Ended December 31, 2022 ($ millions)	**Total Oil Sands**	**Condensate**	**Third-party Sourced**	**Other**	**Total Oil Sands**
Gross Sales	**19,609**	10,307	4,409	358	**34,683**
Royalties	**4,482**	—	—	11	**4,493**
Purchased Product	**—**	—	4,409	309	**4,718**
Transportation and Blending	**1,686**	10,307	—	43	**12,036**
Operating	**2,941**	—	—	(11)	**2,930**
Netback	**10,500**	—	—	6	**10,506**
Realized (Gain) Loss on Risk Management	**1,527**	—	—	—	**1,527**
Operating Margin	**8,973**	—	—	6	**8,979**

Conventional

Three Months Ended March 31, 2023 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other	Conventional
Gross Sales	**491**	483	63	**1,037**
Royalties	**54**	—	—	**54**
Purchased Product	**—**	483	—	**483**
Transportation and Blending	**45**	—	36	**81**
Operating	**146**	—	4	**150**
Netback	**246**	—	23	**269**
Realized (Gain) Loss on Risk Management	**8**	—	—	**8**
Operating Margin	**238**	—	23	**261**

Three Months Ended June 30, 2023 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other	Conventional
Gross Sales	**238**	337	45	**620**
Royalties	**5**	—	(1)	**4**
Purchased Product	**—**	337	—	**337**
Transportation and Blending	**39**	—	27	**66**
Operating	**139**	—	5	**144**
Netback	**55**	—	14	**69**
Realized (Gain) Loss on Risk Management	**(4)**	—	—	**(4)**
Operating Margin	**59**	—	14	**73**

Three Months Ended December 31, 2022 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other	Conventional
Gross Sales	**555**	563	35	**1,153**
Royalties	**69**	—	1	**70**
Purchased Product	**—**	563	—	**563**
Transportation and Blending	**47**	—	12	**59**
Operating	**135**	—	3	**138**
Netback	**304**	—	19	**323**
Realized (Gain) Loss on Risk Management	**75**	—	—	**75**
Operating Margin	**229**	—	19	**248**

Twelve Months Ended December 31, 2022 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other	Conventional
Gross Sales	**2,238**	2,023	178	**4,439**
Royalties	**297**	—	1	**298**
Purchased Product	**—**	2,023	—	**2,023**
Transportation and Blending	**147**	—	103	**250**
Operating	**520**	—	21	**541**
Netback	**1,274**	—	53	**1,327**
Realized (Gain) Loss on Risk Management	**84**	8	—	**92**
Operating Margin	**1,190**	(8)	53	**1,235**

Prior Period Revisions

Certain comparative information presented in the Consolidated Statements of Earnings (Loss) and segment disclosures was revised.

Classification Revisions

During the three months ended September 30, 2023, the Company made adjustments to ensure the consistent treatment of sales between segments and to correct the elimination of these transactions on consolidation. The following adjustments were made:

- Report Conventional segment sales between segments on a gross basis, which resulted in a reclassification between gross sales and transportation and blending expense.
- Report sales of feedstock between the Oil Sands, Conventional and U.S. Manufacturing segments on a net basis, which resulted in a reclassification between gross sales and purchased product.

Offsetting adjustments were made to the Corporate and Eliminations segment. The above items had no impact to net earnings (loss), operating margin, segment income (loss), cash flows or financial position.

It was also identified that the elimination of sales of diluent, natural gas and associated transportation costs between segments were recorded to the incorrect line item in the Corporate and Eliminations segment. The adjustment resulted in an understatement of operating expense, overstatement of purchased product and an overstatement of transportation and blending expense on the Consolidated Statements of Earnings (Loss). There was no impact to net earnings (loss), operating margin, segment income (loss), cash flows or financial position.

Change to Reporting Segments

In September 2022, the Company completed the divestiture of the majority of the retail fuels business. In December 2022, Management elected to aggregate the remaining commercial fuels business and the historical retail fuels business into the Canadian Manufacturing segment. Comparative periods were reclassified to reflect this change, with no impact to net earnings (loss), cash flows or financial position.

The following tables reconcile the amounts previously reported in the Consolidated Statements of Earnings (Loss) and segmented disclosures to the corresponding revised amounts:

($ millions)	Three Months Ended March 31, 2023 Previously Reported	Revisions	Revised Balance
Oil Sands Segment			
Gross Sales [1]	5,911	(204)	**5,707**
Purchased Product [1]	559	(204)	**355**
	5,352	—	**5,352**
Conventional Segment			
Gross Sales [1]	1,031	6	**1,037**
Purchased Product [1]	510	(27)	**483**
Transportation and Blending	48	33	**81**
	473	—	**473**
U.S. Manufacturing Segment			
Gross Sales [1]	5,860	(231)	**5,629**
Purchased Product [1]	5,129	(231)	**4,898**
	731	—	**731**
Corporate and Eliminations Segment			
Gross Sales [1]	(1,925)	429	**(1,496)**
Purchased Product [1]	(1,499)	479	**(1,020)**
Transportation and Blending	(141)	(134)	**(275)**
Operating	(231)	84	**(147)**
	(54)	—	**(54)**
Consolidated			
Purchased Product	5,792	17	**5,809**
Transportation and Blending	2,853	(101)	**2,752**
Operating	1,552	84	**1,636**
	2,661	—	**2,661**

(1) Includes revisions to gross sales and purchased product of $204 million in the Oil Sands segment, $27 million in the Conventional segment and $231 million in the U.S. Manufacturing segment related to sales of feedstock between these segments resulting from changing volume requirements on a net basis with an offsetting adjustment to the Corporate and Eliminations segment.

($ millions)	Three Months Ended June 30, 2023 Previously Reported	Revisions	Revised Balance	Six Months Ended June 30, 2023 Previously Reported	Revisions	Revised Balance
Oil Sands Segment						
Gross Sales	6,556	(119)	**6,437**	12,467	(323)	**12,144**
Purchased Product	533	(119)	**414**	1,092	(323)	**769**
	6,023	—	**6,023**	11,375	—	**11,375**
Conventional Segment						
Gross Sales	615	5	**620**	1,646	11	**1,657**
Purchased Product	352	(15)	**337**	862	(42)	**820**
Transportation and Blending	46	20	**66**	94	53	**147**
	217	—	**217**	690	—	**690**
U.S. Manufacturing Segment						
Gross Sales	6,198	(134)	**6,064**	12,058	(365)	**11,693**
Purchased Product	5,498	(134)	**5,364**	10,627	(365)	**10,262**
	700	—	**700**	1,431	—	**1,431**
Corporate and Eliminations Segment						
Gross Sales (1)	(2,092)	248	**(1,844)**	(4,017)	677	**(3,340)**
Purchased Product (1)	(1,757)	287	**(1,470)**	(3,256)	766	**(2,490)**
Transportation and Blending	(109)	(98)	**(207)**	(250)	(232)	**(482)**
Operating	(185)	59	**(126)**	(416)	143	**(273)**
	(41)	—	**(41)**	(95)	—	**(95)**
Consolidated						
Purchased Product	5,709	19	**5,728**	11,501	36	**11,537**
Transportation and Blending	2,641	(78)	**2,563**	5,494	(179)	**5,315**
Operating	1,541	59	**1,600**	3,093	143	**3,236**
	9,891	—	**9,891**	20,088	—	**20,088**

(1) The three and six months ended June 30, 2023, includes revisions to gross sales and purchased product of $119 million and $323 million in the Oil Sands segment, $15 million and $42 million in the Conventional segment and $134 million and $365 million in the U.S. Manufacturing segment for the reasons noted above with an offsetting adjustment to the Corporate and Eliminations segment.

($ millions)	Three Months Ended March 31, 2022 Previously Reported	Revisions	Segment Aggregation	Revised Balance
Conventional Segment				
Gross Sales	1,112	25	—	**1,137**
Transportation and Blending	34	25	—	**59**
	1,078	—	—	**1,078**
Canadian Manufacturing Segment				
Gross Sales	1,044	—	563	**1,607**
Purchased Product	804	2	529	**1,335**
Transportation and Blending	2	(2)	—	**—**
Operating	124	—	27	**151**
Depreciation, Depletion and Amortization	42	—	8	**50**
	72	—	(1)	**71**
Retail Segment				
Gross Sales	694	—	(694)	**—**
Purchased Product	660	—	(660)	**—**
Operating	27	—	(27)	**—**
Depreciation, Depletion and Amortization	8	—	(8)	**—**
	(1)	—	1	**—**
Corporate and Eliminations Segment				
Gross Sales	(1,761)	(25)	131	**(1,655)**
Purchased Product	(1,282)	39	131	**(1,112)**
Transportation and Blending	(221)	(110)	—	**(331)**
Operating	(267)	46	—	**(221)**
	9	—	—	**9**
Consolidated				
Purchased Product	7,482	41	—	**7,523**
Transportation and Blending	2,975	(87)	—	**2,888**
Operating	1,287	46	—	**1,333**
	11,744	—	—	**11,744**

($ millions)	Three Months Ended June 30, 2022 Previously Reported	Revisions	Segment Aggregation	Revised Balance	Six Months Ended June 30, 2022 Previously Reported	Revisions	Segment Aggregation	Revised Balance
Conventional Segment								
Gross Sales	1,079	34	—	**1,113**	2,191	59	—	**2,250**
Transportation and Blending	34	34	—	**68**	68	59	—	**127**
	1,045	—	—	**1,045**	2,123	—	—	**2,123**
Canadian Manufacturing Segment								
Gross Sales	1,521	—	724	**2,245**	2,565	—	1,287	**3,852**
Purchased Product	1,296	(2)	686	**1,980**	2,100	—	1,215	**3,315**
Transportation and Blending	(2)	2	—	**—**	—	—	—	**—**
Operating	180	—	31	**211**	304	—	58	**362**
Depreciation, Depletion and Amortization	64	—	8	**72**	106	—	16	**122**
	(17)	—	(1)	**(18)**	55	—	(2)	**53**
Retail Segment								
Gross Sales	849	—	(849)	**—**	1,543	—	(1,543)	**—**
Purchased Product	811	—	(811)	**—**	1,471	—	(1,471)	**—**
Operating	31	—	(31)	**—**	58	—	(58)	**—**
Depreciation, Depletion and Amortization	8	—	(8)	**—**	16	—	(16)	**—**
	(1)	—	1	**—**	(2)	—	2	**—**
Corporate and Eliminations Segment								
Gross Sales	(1,782)	(34)	125	**(1,691)**	(3,543)	(59)	256	**(3,346)**
Purchased Product	(1,111)	69	125	**(917)**	(2,393)	108	256	**(2,029)**
Transportation and Blending	(188)	(145)	—	**(333)**	(409)	(255)	—	**(664)**
Operating	(395)	42		**(353)**	(662)	88	—	**(574)**
	(88)	—	—	**(88)**	(79)	—	—	**(79)**
Consolidated								
Purchased Product	9,396	67	—	**9,463**	16,878	108	—	**16,986**
Transportation and Blending	3,048	(109)	—	**2,939**	6,023	(196)	—	**5,827**
Operating	1,481	42	—	**1,523**	2,768	88	—	**2,856**
	13,925	—	—	**13,925**	25,669	—	—	**25,669**

($ millions)	Three Months Ended September 30, 2022 Previously Reported	Revisions	Segment Aggregation	Revised Balance	Nine Months Ended September 30, 2022 Previously Reported	Revisions	Segment Aggregation	Revised Balance
Oil Sands Segment								
Gross Sales	8,778	(14)	—	**8,764**	28,044	(14)	—	**28,030**
Purchased Product	1,933	(14)	—	**1,919**	4,216	(14)	—	**4,202**
	6,845	—	—	**6,845**	23,828	—	—	**23,828**
Conventional Segment								
Gross Sales	1,010	26	—	**1,036**	3,201	85	—	**3,286**
Transportation and Blending	38	26	—	**64**	106	85	—	**191**
	972	—	—	**972**	3,095	—	—	**3,095**
Canadian Manufacturing Segment								
Gross Sales	1,478	—	690	**2,168**	4,043	—	1,977	**6,020**
Purchased Product	1,092	3	655	**1,750**	3,192	3	1,870	**5,065**
Transportation and Blending	3	(3)	—	**—**	3	(3)	—	**—**
Operating	134	—	38	**172**	438	—	96	**534**
Depreciation, Depletion and Amortization	37	—	5	**42**	143	—	21	**164**
	212	—	(8)	**204**	267	—	(10)	**257**
Retail Segment								
Gross Sales	881	—	(881)	**—**	2,424	—	(2,424)	**—**
Purchased Product	846	—	(846)	**—**	2,317	—	(2,317)	**—**
Operating	38	—	(38)	**—**	96	—	(96)	**—**
Depreciation, Depletion and Amortization	5	—	(5)	**—**	21	—	(21)	**—**
	(8)	—	8	**—**	(10)	—	10	**—**
U.S. Manufacturing Segment								
Gross Sales	8,719	(14)	—	**8,705**	23,702	(14)	—	**23,688**
Purchased Product	7,944	(14)	—	**7,930**	20,365	(14)	—	**20,351**
	775	—	—	**775**	3,337	—	—	**3,337**
Corporate and Eliminations Segment								
Gross Sales	(2,619)	2	191	**(2,426)**	(6,162)	(57)	447	**(5,772)**
Purchased Product	(2,267)	65	191	**(2,011)**	(4,660)	173	447	**(4,040)**
Transportation and Blending	(119)	(128)	—	**(247)**	(528)	(383)	—	**(911)**
Operating	(256)	65	—	**(191)**	(918)	153	—	**(765)**
	23	—	—	**23**	(56)	—	—	**(56)**
Consolidated								
Purchased Product	10,012	40	—	**10,052**	26,890	148	—	**27,038**
Transportation and Blending	2,684	(105)	—	**2,579**	8,707	(301)	—	**8,406**
Operating	1,439	65	—	**1,504**	4,207	153	—	**4,360**
	14,135	—	—	**14,135**	39,804	—	—	**39,804**

($ millions)	Three Months Ended December 31, 2022 Previously Reported	Revisions	Segment Aggregation	Revised Balance	Twelve Months Ended December 31, 2022 Previously Reported	Revisions	Segment Aggregation	Revised Balance
Oil Sands Segment								
Gross Sales	6,731	(78)	—	**6,653**	34,775	(92)	—	**34,683**
Purchased Product	594	(78)	—	**516**	4,810	(92)	—	**4,718**
	6,137	—	—	**6,137**	29,965	—	—	**29,965**
Conventional Segment								
Gross Sales	1,131	22	—	**1,153**	4,332	107	—	**4,439**
Transportation and Blending	37	22	—	**59**	143	107	—	**250**
	1,094	—	—	**1,094**	4,189	—	—	**4,189**
U.S. Manufacturing Segment								
Gross Sales	6,608	(78)	—	**6,530**	30,310	(92)	—	**30,218**
Purchased Product	5,747	(78)	—	**5,669**	26,112	(92)	—	**26,020**
	861	—	—	**861**	4,198	—	—	**4,198**
Corporate and Eliminations Segment								
Gross Sales	(1,749)	134	—	**(1,615)**	(7,464)	77	—	**(7,387)**
Purchased Product	(1,320)	168	—	**(1,152)**	(5,533)	341	—	**(5,192)**
Transportation and Blending	(136)	(128)	—	**(264)**	(664)	(511)	—	**(1,175)**
Operating	(352)	94	—	**(258)**	(1,270)	247	—	**(1,023)**
	59	—	—	**59**	3	—	—	**3**
Consolidated								
Purchased Product	6,908	12	—	**6,920**	33,801	157	—	**33,958**
Transportation and Blending	2,826	(106)	—	**2,720**	11,530	(404)	—	**11,126**
Operating	1,362	94	—	**1,456**	5,569	247	—	**5,816**
	11,096	—	—	**11,096**	50,900	—	—	**50,900**

($ millions)	Three Months Ended September 30, 2021 Previously Reported	Revisions	Segment Aggregation	Revised Balance	Three Months Ended December 31, 2021 Previously Reported	Revisions	Segment Aggregation	Revised Balance
Conventional Segment								
Gross Sales	833	21	—	**854**	1,000	21	—	**1,021**
Transportation and Blending	20	21	—	**41**	17	21	—	**38**
	813	—	—	**813**	983	—	—	**983**
Canadian Manufacturing Segment								
Gross Sales	1,215	—	484	**1,699**	1,363	—	493	**1,856**
Purchased Product	986	—	443	**1,429**	1,128	—	460	**1,588**
Operating	99	—	25	**124**	104	—	25	**129**
Depreciation, Depletion and Amortization	41	—	11	**52**	40	—	23	**63**
	89	—	5	**94**	91	—	(15)	**76**
Retail Segment								
Gross Sales	592	—	(592)	**—**	618	—	(618)	**—**
Purchased Product	551	—	(551)	**—**	585	—	(585)	**—**
Operating	25	—	(25)	**—**	25	—	(25)	**—**
Depreciation, Depletion and Amortization	11	—	(11)	**—**	23	—	(23)	**—**
	5	—	(5)	**—**	(15)	—	15	**—**
Corporate and Eliminations Segment								
Gross Sales	(1,450)	(21)	108	**(1,363)**	(1,831)	(21)	125	**(1,727)**
Purchased Product	(1,091)	46	108	**(937)**	(1,369)	39	125	**(1,205)**
Transportation and Blending	(171)	(94)	—	**(265)**	(200)	(105)	—	**(305)**
Operating	(187)	27	—	**(160)**	(266)	45	—	**(221)**
	(1)	—	—	**(1)**	4	—	—	**4**
Consolidated								
Purchased Product	6,691	46	—	**6,737**	7,177	39	—	**7,216**
Transportation and Blending	1,966	(73)	—	**1,893**	2,399	(84)	—	**2,315**
Operating	1,150	27	—	**1,177**	1,288	45	—	**1,333**
	9,807	—	—	**9,807**	10,864	—	—	**10,864**

($ millions)	Twelve Months Ended December 31, 2021 Previously Reported	Revisions	Segment Aggregation	Revised Balance
Conventional Segment				
Gross Sales	3,235	81	—	**3,316**
Transportation and Blending	74	81	—	**155**
	3,161	—	—	**3,161**
Canadian Manufacturing Segment				
Gross Sales	4,472	—	1,743	**6,215**
Purchased Product	3,552	—	1,604	**5,156**
Operating	388	—	98	**486**
Depreciation, Depletion and Amortization	167	—	59	**226**
	365	—	(18)	**347**
Retail Segment				
Gross Sales	2,158	—	(2,158)	**—**
Purchased Product	2,019	—	(2,019)	**—**
Operating	98	—	(98)	**—**
Depreciation, Depletion and Amortization	59	—	(59)	**—**
	(18)	—	18	**—**
Corporate and Eliminations Segment				
Gross Sales	(5,706)	(81)	415	**(5,372)**
Purchased Product	(4,259)	163	415	**(3,681)**
Transportation and Blending	(676)	(363)	—	**(1,039)**
Operating	(783)	119	—	**(664)**
	12	—	—	**12**
Consolidated				
Purchased Product	23,326	163	—	**23,489**
Transportation and Blending	8,038	(282)	—	**7,756**
Operating	4,716	119	—	**4,835**
	36,080	—	—	**36,080**