Cenovus Energy Inc.

Management's Discussion and Analysis (unaudited)

For the Periods Ended September 30, 2024

(Canadian Dollars)

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the periods ended September 30, 2024

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, joint arrangements, and partnership interests held directly or indirectly by, Cenovus Energy Inc.) dated October 30, 2024, should be read in conjunction with our September 30, 2024 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2023 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2023 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as at October 30, 2024, 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 October 30, 2024. 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, do 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 is indicated, and in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") (the "IFRS Accounting Standards"). Production volumes are presented on a before royalties basis. Refer to the Abbreviations and Definitions 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 and economically 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, natural gas and NGLs production through to the sale of finished products such as transportation fuels.

Our Strategy

At Cenovus, our purpose is to energize the world to make people's lives better. Our strategy is focused on maximizing shareholder value over the long-term through sustainable, low-cost, diversified and integrated energy leadership. Our five strategic objectives include: delivering top-tier safety performance; maximizing value through competitive cost structures and optimizing margins; a focus on financial discipline, including reaching and maintaining targeted debt levels while positioning Cenovus for resiliency through commodity price cycles; a disciplined approach to allocating capital to projects that generate returns at the bottom of the commodity price cycle; and the prioritization of 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 14, 2023, we released our 2024 budget focused on disciplined capital investment and balancing growth of our base business with meaningful shareholder returns. We will remain focused on safe operations, reducing costs, capital discipline and realizing the full value of our integrated business. Our 2024 corporate guidance was updated on July 31, 2024, and is available on our website at cenovus.com. For further details, see the Outlook section of this MD&A.

Our Operations

The Company operates through the following reportable segments:

Upstream Segments

- **Oil Sands,** includes the development and production of bitumen and heavy oil in northern Alberta and Saskatchewan. Cenovus's oil sands assets include Foster Creek, Christina Lake, Sunrise, 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 Husky-CNOOC Madura Ltd. ("HCML"), which is engaged in the exploration for and production of NGLs and natural gas in offshore Indonesia.

Downstream Segments

- **Canadian Refining,** 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. Refining,** 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, held through WRB Refining LP ("WRB"), a jointly owned entity with operator Phillips 66. Cenovus markets some of its own and third-party refined products including gasoline, diesel, jet fuel and asphalt.

Corporate and Eliminations

Corporate and Eliminations, 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 feedstock and internal usage of crude oil, natural gas, condensate, other NGLs and refined products between segments; transloading services provided to the Oil Sands segment by the Company's crude-by-rail terminal; the sale of condensate extracted from blended crude oil production in the Canadian Refining 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 solid operating performance across our upstream assets, and the safe execution of turnarounds at several of our upstream assets and the Lima Refinery in the U.S. Refining segment. The cost of maintenance activities combined with significant volatility in market crack spreads and the declining crude oil price environment impacted our financial results compared with the second quarter of 2024.

- **Delivered safe and reliable operations.** We delivered safe operations across our business and safely completed turnarounds at Christina Lake, at certain Conventional assets, and at the Lima Refinery. Turnarounds are essential to ensure long-term operational efficiency. Safety continues to be our top priority.
- **Distributed significant returns to shareholders.** We achieved our Net Debt target in July 2024. In the quarter, we returned $1.1 billion to common shareholders, composed of the purchase of 28.4 million common shares for $732 million through our normal course issuer bid ("NCIB") and $329 million through common share base dividends. On October 30, 2024, our Board of Directors declared a fourth quarter base dividend of $0.180 per common share.
- **Reported solid financial results.** Adjusted Funds Flow was $2.0 billion and cash from operating activities was $2.5 billion. These decreased from the second quarter of 2024 due to the declines in benchmark prices, offset by increased refined product production in our downstream operations. Net earnings for the quarter was $820 million compared with $1.0 billion in the second quarter.
- **Maintained strong upstream production.** Upstream production was 771.3 thousand barrels of oil equivalent per day, a decrease of 29.5 thousand barrels of oil equivalent per day from the second quarter of 2024, due to significant turnaround activity. We safely completed turnarounds at Christina Lake and in our Conventional Segment on schedule.
- **Improved downstream throughput.** Average crude oil unit throughput (or "throughput") was 642.9 thousand barrels per day in the quarter, an increase of 20.2 thousand barrels per day from the second quarter. The increase was largely driven by the Lloydminster Upgrader (the "Upgrader") returning to full operations following turnaround activity in the second quarter. In September, we commenced turnaround activity at the Lima Refinery. We were able to partially mitigate the impact of the turnaround by processing intermediate products at the Toledo Refinery.
- **Progressed key Atlantic projects.** Refit work on the SeaRose asset life extension ("ALE") project, which began in the first quarter of 2024, was completed at the dry dock. The SeaRose floating production, storage and offloading unit ("FPSO") is currently en route to the White Rose field, where reconnecting and commissioning activities will take place. Production is expected to resume around year-end. At the West White Rose project, we continue to make progress and we were approximately 85 percent complete at the end of the quarter.
- **Advanced our Oil Sands growth projects.** The Narrows Lake tie-back pipeline to Christina Lake is approximately 93 percent constructed and is on track to achieving mechanical completion by the end of the year. As part of the Sunrise growth program, we brought two new well pads online. Construction of the Foster Creek optimization project is approximately 43 percent complete. At our Lloydminster conventional heavy oil assets, we continue to progress on our planned drilling program with four rigs currently in operation.

Summary of Quarterly Results

($ millions, except where indicated)	Nine Months Ended September 30, 2024	Nine Months Ended September 30, 2023	2024 Q3	2024 Q2	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4
Upstream Production Volumes [1] (MBOE/d)	**790.9**	768.7	**771.3**	800.8	800.9	808.6	797.0	729.9	779.0	806.9
Downstream Total Processed Inputs [2] [3] (Mbbls/d)	**670.4**	580.4	**674.4**	652.9	683.8	605.7	691.3	566.9	480.7	491.3
Crude Oil Unit Throughput [2] (Mbbls/d)	**640.3**	554.1	**642.9**	622.7	655.2	579.1	664.3	537.8	457.9	473.3
Downstream Production Volumes [1] [2] (Mbbls/d)	**683.3**	589.8	**685.2**	659.5	702.1	627.4	706.0	571.9	487.7	506.3
Revenues	**42,531**	39,070	**14,249**	14,885	13,397	13,134	14,577	12,231	12,262	14,063
Operating Margin [4]	**8,535**	8,871	**2,408**	2,936	3,191	2,151	4,369	2,400	2,102	2,782
Cash From (Used In) Operating Activities	**7,206**	4,442	**2,474**	2,807	1,925	2,946	2,738	1,990	(286)	2,970
Adjusted Funds Flow [4]	**6,563**	6,741	**1,960**	2,361	2,242	2,062	3,447	1,899	1,395	2,346
Per Share - Basic [4] ($)	**3.53**	3.55	**1.06**	1.27	1.20	1.10	1.82	1.00	0.73	1.22
Per Share - Diluted [4] ($)	**3.50**	3.48	**1.05**	1.26	1.19	1.08	1.81	0.98	0.71	1.19
Capital Investment	**3,537**	3,128	**1,346**	1,155	1,036	1,170	1,025	1,002	1,101	1,274
Free Funds Flow [4]	**3,026**	3,613	**614**	1,206	1,206	892	2,422	897	294	1,072
Excess Free Funds Flow [4]	**1,713**	1,995	**146**	735	832	471	1,989	505	(499)	786
Net Earnings (Loss)	**2,996**	3,366	**820**	1,000	1,176	743	1,864	866	636	784
Per Share - Basic ($)	**1.60**	1.76	**0.44**	0.53	0.62	0.39	0.98	0.45	0.33	0.40
Per Share - Diluted ($)	**1.59**	1.72	**0.42**	0.53	0.62	0.32	0.97	0.44	0.31	0.39
Total Assets	**54,680**	54,427	**54,680**	56,000	54,994	53,915	54,427	53,747	54,000	55,869
Total Long-Term Liabilities	**18,692**	18,395	**18,692**	18,945	18,884	18,993	18,395	19,831	19,917	20,259
Long-Term Debt, Including Current Portion	**7,199**	7,224	**7,199**	7,275	7,227	7,108	7,224	8,534	8,681	8,691
Net Debt	**4,196**	5,976	**4,196**	4,258	4,827	5,060	5,976	6,367	6,632	4,282
Cash Returns to Common Shareholders	**2,513**	2,040	**1,061**	1,025	427	722	1,225	575	240	807
Common Shares – Base Dividends	**925**	729	**329**	334	262	261	264	265	200	201
Base Dividends Per Common Share ($)	**0.500**	0.385	**0.180**	0.180	0.140	0.140	0.140	0.140	0.105	0.105
Common Shares – Variable Dividends	**251**	—	**—**	251	—	—	—	—	—	219
Variable Dividends Per Common Share ($)	**0.135**	—	**—**	0.135	—	—	—	—	—	0.114
Purchase of Common Shares Under NCIB	**1,337**	711	**732**	440	165	350	361	310	40	387
Payment for Purchase of Warrants	**—**	600	**—**	—	—	111	600	—	—	—
Dividends Paid on Preferred Shares	**27**	27	**9**	9	9	9	—	9	18	—

(1) Refer to the Operating and Financial Results section of this MD&A for a summary of total production by product type.
(2) Represents Cenovus's net interest in refining operations.
(3) Total processed inputs include crude oil and other feedstocks. Blending is excluded.
(4) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

OPERATING AND FINANCIAL RESULTS

Selected Operating and Financial Results — Upstream

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2024	**Percent Change**	2023	**2024**	**Percent Change**	2023
Production Volumes by Segment [(1)] (MBOE/d)						
Oil Sands	**587.7**	**(3)**	603.4	**604.8**	**3**	589.0
Conventional	**118.1**	**(7)**	127.2	**120.5**	**2**	118.5
Offshore	**65.5**	**(1)**	66.4	**65.6**	**7**	61.2
Total Production Volumes	**771.3**	**(3)**	797.0	**790.9**	**3**	768.7
Production Volumes by Product						
Bitumen (Mbbls/d)	**569.6**	**(3)**	586.0	**585.4**	**3**	570.6
Heavy Crude Oil (Mbbls/d)	**16.3**	**4**	15.6	**17.4**	**5**	16.5
Light Crude Oil (Mbbls/d)	**13.6**	**(11)**	15.2	**13.2**	**(2)**	13.5
NGLs (Mbbls/d)	**31.0**	**(13)**	35.6	**32.2**	**1**	31.9
Conventional Natural Gas (MMcf/d)	**844.6**	**(3)**	867.4	**855.8**	**5**	818.1
Total Production Volumes (MBOE/d)	**771.3**	**(3)**	797.0	**790.9**	**3**	768.7
Per-Unit Operating Expenses by Segment [(2)] ($/BOE)						
Oil Sands	**11.17**	**(11)**	12.56	**11.50**	**(12)**	13.09
Conventional	**12.77**	**3**	12.36	**12.35**	**(7)**	13.26
Offshore [(3)]	**17.97**	**23**	14.66	**19.36**	**11**	17.37

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

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

(3) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A. Offshore Per-Unit Operating Expenses reflect Cenovus's 40 percent interest in HCML which is accounted for using the equity method in the interim Consolidated Financial Statements. Operating expenses for the Offshore segment, excluding Indonesia, for the three and nine months ended September 30, 2024, were $92 million and $319 million, respectively (2023 – $76 million and $281 million, respectively).

Total upstream production decreased in the third quarter of 2024 compared with 2023 primarily due to:

- Turnaround activities in our Oil Sands segment and in our Conventional segment.
- The divestiture of non-core assets in our Conventional segment in the first and third quarters of 2024.

The decreases were partially offset by:

- The Terra Nova FPSO resuming production in November 2023, partially offset by suspended production at the White Rose field in December 2023 for the SeaRose ALE project.

Year to date, upstream production increased due to:

- Successful results from redevelopment and sustaining programs, as well as base well optimizations which resulted in increased production in our Oil Sands segment.
- The successful restart of operations in the Conventional segment following the temporary shut-in of a significant portion of production in response to wildfire activity in the second quarter of 2023.
- The temporary unplanned outage in China related to the disconnection of the umbilical by a third-party vessel in April 2023.

The year-to-date increases were partially offset by the decreases noted above for the three months ended September 30, 2024 compared with 2023.

For the nine months ended September 30, 2024, per-unit operating expenses decreased in the Oil Sands segment and the Conventional segment compared with 2023, due to higher sales volumes. The Oil Sands segment also benefited from lower fuel operating costs due to significant declines in natural gas pricing. Overall, the Company has managed inflationary pressures through the use of long-term contracts, working with vendors and managing the timing of purchases of long-lead items.

Selected Operating and Financial Results — Downstream

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2024	**Percent Change**	2023	**2024**	**Percent Change**	2023
Crude Oil Unit Throughput by Segment (Mbbls/d)						
Canadian Refining	**99.4**	**(8)**	108.4	**85.8**	**(15)**	100.8
U.S. Refining	**543.5**	**(2)**	555.9	**554.5**	**22**	453.3
Total Crude Oil Unit Throughput	**642.9**	**(3)**	664.3	**640.3**	**16**	554.1
Production Volumes by Product [(1)] (Mbbls/d)						
Gasoline	**259.7**	**(3)**	267.6	**273.4**	**25**	218.3
Distillates [(2)]	**217.1**	**3**	209.9	**216.7**	**22**	178.0
Synthetic Crude Oil	**47.3**	**(11)**	53.2	**38.4**	**(20)**	47.9
Asphalt	**46.1**	**14**	40.4	**43.4**	**25**	34.8
Ethanol	**5.5**	**(2)**	5.6	**5.1**	**4**	4.9
Other	**109.5**	**(15)**	129.3	**106.3**	**—**	105.9
Total Production Volumes	**685.2**	**(3)**	706.0	**683.3**	**16**	589.8
Per-Unit Operating Expenses by Segment [(3) (4)] ($/bbl)						
Canadian Refining	**14.63**	**20**	12.23	**26.65**	**103**	13.10
U.S. Refining	**14.37**	**22**	11.74	**12.89**	**(13)**	14.76

(1) Refer to the Canadian Refining and U.S. Refining Reportable Segments section of this MD&A for a summary of production by product by segment.
(2) Includes diesel and jet fuel.
(3) Specified financial measure. Per-unit metrics are calculated based on total processed inputs. See the Specified Financial Measures Advisory of this MD&A.
(4) Inclusive of turnaround costs. In the Canadian Refining segment, operating expenses represent expenses associated with the Lloydminster Upgrader, the Lloydminster Refinery and the commercial fuels business.

In the quarter, our downstream operations were significantly impacted by turnaround activity, combined with unplanned outages at our U.S. Refining assets. The Lima Refinery turnaround commenced in early September 2024. We were able to partially mitigate the impact of the turnaround by processing intermediate products from the Lima Refinery at our Toledo Refinery. This allowed the Lima Refinery's crude unit to continue operations. In July, the Upgrader ramped up to full operations following turnaround activity in the second quarter of 2024. These events resulted in decreased total downstream throughput and total refined product production, and increased operating expenses, compared with 2023.

Year to date, total downstream throughput and refined product production increased compared with 2023. The impact of turnaround activity on production and throughput, as discussed above, was offset by realizing a full period of production at the Toledo and Superior refineries. We acquired the Toledo Refinery on February 28, 2023 (the "Toledo Acquisition") and we ramped up the Superior Refinery in 2023.

For the nine months ended September 30, 2024, per-unit operating expenses increased in the Canadian Refining segment, compared with 2023, primarily due to the turnaround at the Upgrader. Per-unit operating expenses in the U.S. Refining segment decreased year-to-date, as the increase in operating expenses caused by turnaround activity was more than offset by the increase in total processed inputs.

Selected Consolidated Financial Results

Revenues

In the three months ended September 30, 2024, revenues decreased two percent compared with 2023, due to lower benchmark crude oil, natural gas and refined product pricing, combined with lower sales volumes in our upstream operations.

In the nine months ended September 30, 2024, revenues increased nine percent compared with 2023. Upstream revenue increased primarily due to the narrowing of the WTI-WCS and condensate-WCS differentials, with relatively consistent WTI prices and increased sales volumes. Downstream revenues increased primarily due to higher sales volumes, partially offset by lower refined product pricing.

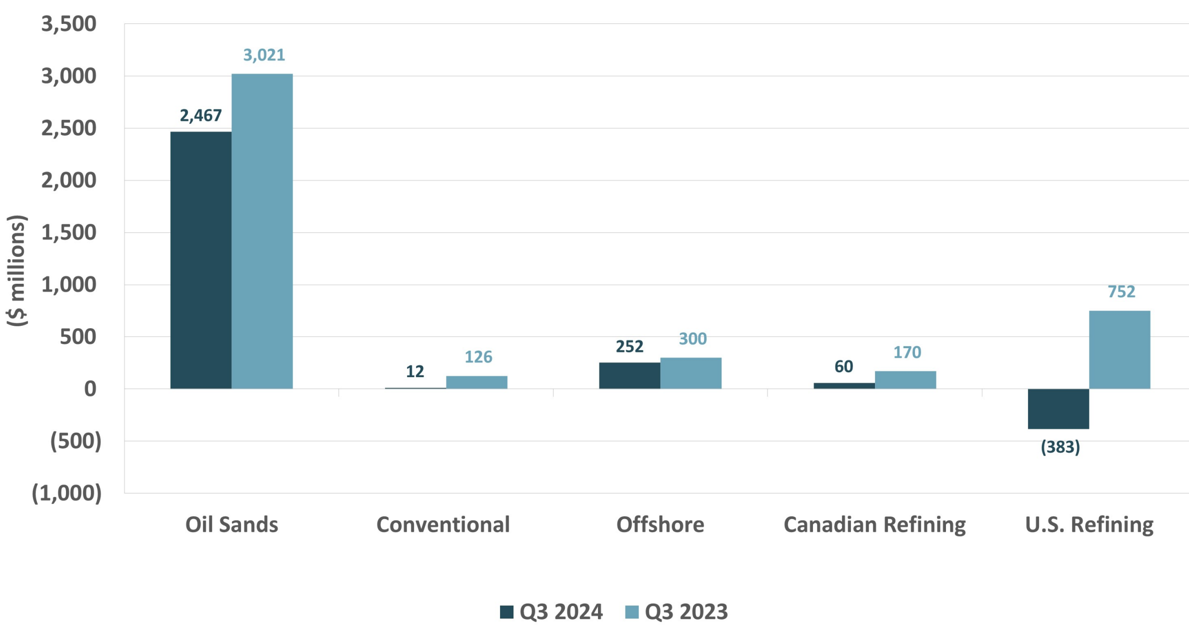
Operating Margin

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

($ millions)	Three Months Ended September 30, 2024	2023	Nine Months Ended September 30, 2024	2023
Gross Sales				
External Sales	**15,178**	15,712	**45,066**	41,438
Intersegment Sales	**2,309**	2,729	**6,620**	6,069
	17,487	18,441	**51,686**	47,507
Royalties	**(929)**	(1,135)	**(2,535)**	(2,368)
Revenues	**16,558**	17,306	**49,151**	45,139
Expenses				
Purchased Product	**9,725**	8,847	**26,629**	22,874
Transportation and Blending	**2,661**	2,397	**8,515**	8,194
Operating Expenses	**1,778**	1,692	**5,451**	5,201
Realized (Gain) Loss on Risk Management Activities	**(14)**	1	**21**	(1)
Operating Margin	**2,408**	4,369	**8,535**	8,871

Operating Margin by Segment

Three Months Ended September 30, 2024 and 2023



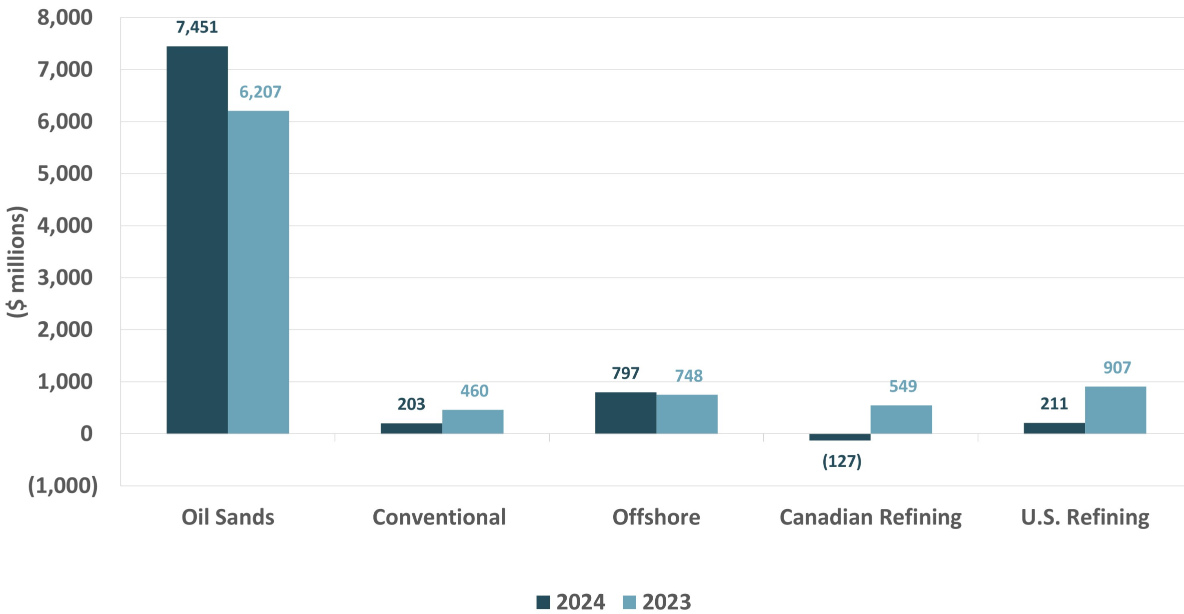
In the third quarter, Operating Margin decreased significantly compared with 2023, primarily due to:

- Lower market crack spreads impacting our U.S. Refining segment, combined with the adverse effect of processing feedstock purchased at higher prices in prior periods in both of our downstream segments.
- Lower crude oil benchmark pricing impacting our Oil Sands segment.
- Higher operating expenses in our downstream segments due to turnaround activity.

These decreases were partially offset by lower royalties in our Oil Sands segment.

Operating Margin in the Conventional segment decreased compared with 2023, primarily due to lower realized natural prices. The decrease was offset by reduced fuel operating costs in the Oil Sands segment.

Nine Months Ended September 30, 2024 and 2023



Year-to-date Operating Margin decreased compared with 2023, due to the factors above, combined with higher royalties in our Oil Sands segment, partially offset by higher crude oil benchmark pricing and increased sales volumes in our Oil Sands 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)	**2024**	2023	**2024**	2023
Cash From (Used in) Operating Activities	**2,474**	2,738	**7,206**	4,442
(Add) Deduct:				
Settlement of Decommissioning Liabilities	**(74)**	(68)	**(170)**	(157)
Net Change in Non-Cash Working Capital	**588**	(641)	**813**	(2,142)
Adjusted Funds Flow	**1,960**	3,447	**6,563**	6,741

Cash from operating activities decreased in the third quarter of 2024, compared with 2023, primarily due to lower Operating Margin, partially offset by changes in non-cash working capital. Changes in non-cash working capital increased cash from operating activities by $588 million primarily due to lower accounts receivable and inventories, partially offset by lower accounts payable.

Cash from operating activities increased in the first nine months of 2024, compared with 2023, primarily due to changes in non-cash working capital, partially offset by lower Operating Margin. In the first nine months of 2023, changes in non-cash working capital were primarily driven by an income tax payment of $1.2 billion.

Adjusted Funds Flow was lower in the three and nine months ended September 30, 2024, compared with the same periods in 2023. The quarter-over-quarter decrease was primarily due to lower Operating Margin, as discussed above, partially offset by lower cash taxes. The year-over-year decrease was primarily due to lower Operating Margin and higher long-term incentive costs paid, partially offset by lower cash taxes, lower net finance costs and the receipt of insurance proceeds related to the Toledo Refinery.

Net Earnings (Loss)

Net earnings in the three months ended September 30, 2024, decreased $1.0 billion to $820 million, compared with 2023, primarily due to decreased Operating Margin, as discussed above, partially offset by lower income tax expense, a foreign exchange gain in 2024 compared with losses in 2023 and lower general and administrative expenses. Net earnings in the nine months ended September 30, 2024, decreased $370 million to $3.0 billion, primarily due to lower Operating Margin and higher depreciation, depletion, amortization and exploration expense, partially offset by gains on the divestiture of assets in 2024 and the receipt of insurance proceeds.

Net Debt

As at ($ millions)	**September 30, 2024**	December 31, 2023
Short-Term Borrowings	**101**	179
Current Portion of Long-Term Debt	**180**	—
Long-Term Portion of Long-Term Debt	**7,019**	7,108
Total Debt	**7,300**	7,287
Cash and Cash Equivalents	**(3,104)**	(2,227)
Net Debt	**4,196**	5,060

Long-term debt increased by $91 million from December 31, 2023, primarily due to the weakening of the Canadian dollar which impacted our U.S. denominated debt. Net Debt decreased by $864 million from December 31, 2023, mainly due to cash from operating activities of $7.2 billion, partially offset by capital investment of $3.5 billion, cash returns to shareholders of $2.5 billion and the weakening of the Canadian dollar discussed above. 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)	**2024**	2023	**2024**	2023
Upstream				
Oil Sands	**681**	590	**1,941**	1,764
Conventional	**106**	100	**300**	323
Offshore	**355**	194	**809**	478
Total Upstream	**1,142**	884	**3,050**	2,565
Downstream				
Canadian Refining	**44**	38	**145**	99
U.S. Refining	**153**	88	**320**	435
Total Downstream	**197**	126	**465**	534
Corporate and Eliminations	**7**	15	**22**	29
Total Capital Investment	**1,346**	1,025	**3,537**	3,128

(1) Includes expenditures on property, plant and equipment ("PP&E"), exploration and evaluation ("E&E") assets and capitalized interest. Excludes capital expenditures related to the HCML joint venture.

Capital investment in the first nine months of 2024 was mainly related to:

- Sustaining activities in the Oil Sands segment, including the drilling of stratigraphic test wells as part of our integrated winter program.
- The progression of the West White Rose project and the SeaRose ALE.
- Growth projects in our Oil Sands segment, including the tie-back of Narrows Lake to Christina Lake, optimization projects at Foster Creek and Sunrise and the progression of the planned drilling program at our Lloydminster conventional heavy oil assets.
- Drilling, completion, tie-in and infrastructure projects in the Conventional segment.
- Sustaining activities at our operated Canadian and U.S. refining assets, and refining reliability projects at our non-operated refineries.

Drilling Activity

Nine Months Ended September 30,	Net Stratigraphic Test Wells and Observation Wells 2024	2023	Net Production Wells (1) 2024	2023
Foster Creek	**82**	87	**17**	34
Christina Lake	**58**	53	**16**	11
Sunrise	**40**	38	**8**	15
Lloydminster Thermal	**25**	8	**18**	2
Lloydminster Conventional Heavy Oil	**8**	1	**23**	21
China	**1**	—	**—**	—
Other	**—**	3	**—**	—
	214	190	**82**	83

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

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, 2024			Nine Months Ended September 30, 2023		
(net wells)	**Drilled**	**Completed**	**Tied-in**	Drilled	Completed	Tied-in
Conventional	**24**	**24**	**17**	30	29	30

In the Offshore segment, we drilled and evaluated one exploration well in China in the first nine months of 2024 (2023 – drilled and completed one (0.4 net) development well at the MAC field in Indonesia).

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)

(Average US$/bbl, unless otherwise indicated)	Nine Months Ended September 30, 2024	Percent Change	2023	Q3 2024	Q2 2024	Q3 2023
Dated Brent	**82.79**	**1**	82.14	**80.18**	84.94	86.76
WTI	**77.54**	**—**	77.39	**75.09**	80.57	82.26
Differential Dated Brent - WTI	**5.25**	**11**	4.75	**5.09**	4.37	4.50
WCS at Hardisty	**62.05**	**4**	59.82	**61.54**	66.96	69.35
Differential WTI - WCS at Hardisty	**15.49**	**(12)**	17.57	**13.55**	13.61	12.91
WCS at Hardisty (C$/bbl)	**84.45**	**5**	80.47	**83.95**	91.63	93.06
WCS at Nederland	**71.03**	**3**	69.12	**68.51**	74.69	77.89
Differential WTI - WCS at Nederland	**6.51**	**(21)**	8.27	**6.58**	5.88	4.37
Condensate (C5 at Edmonton)	**73.71**	**(4)**	76.74	**71.19**	77.14	77.96
Differential Condensate - WTI Premium/(Discount)	**(3.83)**	**489**	(0.65)	**(3.90)**	(3.43)	(4.30)
Differential Condensate - WCS at Hardisty Premium/(Discount)	**11.66**	**(31)**	16.92	**9.65**	10.18	8.61
Condensate (C$/bbl)	**100.28**	**(3)**	103.28	**97.10**	105.55	104.63
Synthetic at Edmonton	**76.38**	**(4)**	79.93	**76.41**	83.32	84.95
Differential Synthetic - WTI Premium/(Discount)	**(1.16)**	**(146)**	2.54	**1.32**	2.75	2.69
Synthetic at Edmonton (C$/bbl)	**103.96**	**(3)**	107.56	**104.22**	114.01	114.01

(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.

Selected Benchmark Prices and Exchange Rates - Continued [1]

(Average US$/bbl, unless otherwise indicated)	Nine Months Ended September 30, 2024	Percent Change	2023	Q3 2024	Q2 2024	Q3 2023
Refined Product Prices						
Chicago Regular Unleaded Gasoline (“RUL”)	**93.62**	**(9)**	102.58	**92.29**	99.09	105.59
Chicago Ultra-low Sulphur Diesel (“ULSD”)	**100.21**	**(9)**	110.52	**96.55**	99.80	113.77
Refining Benchmarks						
Upgrading Differential [2] (C$/bbl)	**19.40**	**(27)**	26.74	**20.26**	22.28	20.85
Chicago 3-2-1 Crack Spread [3]	**18.27**	**(34)**	27.83	**18.62**	18.76	26.06
Group 3 3-2-1 Crack Spread [3]	**18.19**	**(45)**	33.36	**18.95**	18.13	36.96
Renewable Identification Numbers (“RINs”)	**3.65**	**(53)**	7.80	**3.89**	3.39	7.42
Natural Gas Prices						
AECO [4] (C$/Mcf)	**1.45**	**(47)**	2.76	**0.69**	1.18	2.60
NYMEX [5] (US$/Mcf)	**2.10**	**(22)**	2.69	**2.16**	1.89	2.55
Foreign Exchange Rates						
US$ per C$1 - Average	**0.735**	**(1)**	0.743	**0.733**	0.731	0.746
US$ per C$1 - End of Period	**0.741**	**—**	0.740	**0.741**	0.731	0.740
RMB per C$1 - Average	**5.293**	**1**	5.229	**5.255**	5.293	5.402

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

(2) The upgrading differential is the difference between synthetic crude oil at Edmonton and Lloydminster Blend crude oil at Hardisty. The upgrading differential does not precisely mirror the configuration and the product output of our refineries; however, it is used as a general market indicator.

(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) New York Mercantile Exchange (“NYMEX”) natural gas monthly index.

Crude Oil and Condensate Benchmarks

In the third quarter of 2024, crude oil benchmark prices, Brent and WTI, decreased compared with the second quarter of 2024. OPEC+ announced plans this summer to begin unwinding voluntary production cuts and the prospect of increased supply weighed on global oil prices. Geopolitical events related to Russia and Ukraine, Israel and Gaza, Iran, the Red Sea, Venezuela and Guyana continued to add volatility in the third quarter of 2024, but have had a limited impact on global oil markets. Slowing U.S. drilling activity since the beginning of 2023 has reduced global supply growth, tightening global crude supply and demand balances.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices, and the Canadian dollar equivalent is the basis for determining royalty rates for a number of our crude oil properties.

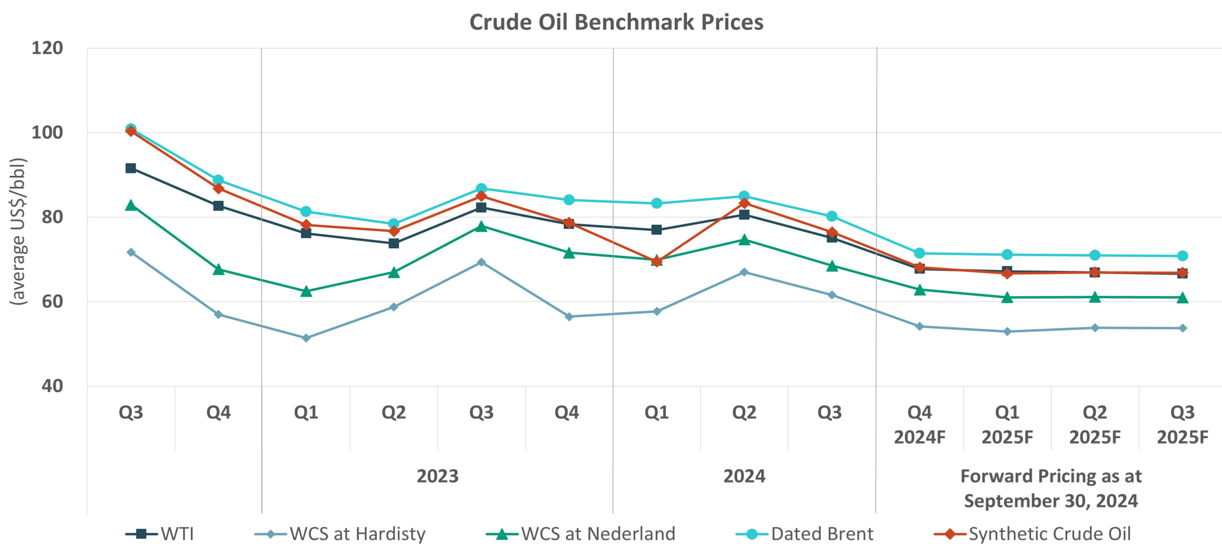
The price received for our Atlantic crude oil and Asia Pacific NGLs is primarily driven by the price of Brent. The Brent-WTI differential widened in the third quarter of 2024 compared with the second quarter of 2024, primarily due to geopolitical tensions in the Middle East and supply disruptions in Libya that impacted Brent pricing more than WTI.

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 start-up of the Trans Mountain Pipeline expansion project (“TMX”) caused the WTI-WCS differential at Hardisty to narrow in the three months ended September 30, 2024, compared with the first and second quarters of 2024. The WTI-WCS differential at Hardisty was wider in the third quarter of 2024 when compared with the same period of 2023, due to the impact of Saudi Arabia’s voluntary production cuts which took effect in July 2023. In the nine months ended September 30, 2024, the WTI-WCS differential at Hardisty narrowed compared with 2023, due to the start-up of TMX and stronger global demand for heavy crude.

WCS at Nederland is a heavy oil benchmark for sales of our product at the U.S. Gulf Coast (“USGC”). The WTI-WCS at Nederland differential is representative of the heavy oil quality differential and is influenced by global heavy oil refining capacity and global heavy oil supply. In the three months ended September 30, 2024, the WTI-WCS at Nederland differential widened, compared with the same period in 2023 and the second quarter of 2024, due to competition at the USGC from heavy crude imports. In the nine months ended September 30, 2024, the WTI-WCS at Nederland differential narrowed due to the voluntary production cuts from OPEC+ members including Saudi Arabia.

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 third quarters of 2024 and 2023, synthetic crude oil at Edmonton was priced at a premium to WTI. For the nine months ended September 30, 2024, synthetic crude oil at Edmonton was priced at a discount to WTI. The weakness in pricing earlier in the year was a result of high synthetic crude oil production in Alberta, an oversupply of light crude which resulted in it being above pipeline capacity on light crude pipelines and limited local storage capacity.



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 25 percent to 35 percent. The Condensate-WCS differential is an important benchmark, as a wider premium 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 blended product sales.

In the three and nine months ended September 30, 2024 and 2023, the average Edmonton condensate benchmark traded at a discount to WTI. Weakness in the three months ended September 30, 2024, was mainly driven by lower seasonal diluent blending ratios. For the nine months ended September 30, 2024, weakness was influenced by low light crude oil prices in the first quarter of 2024 in Alberta, as an oversupply of light crude exceeded pipeline takeaway capacity. Weak international naphtha demand has further weighed on prices in 2024. Weak demand reduces the price of USGC condensate that is imported to Canada, resulting in lower blending costs.

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.

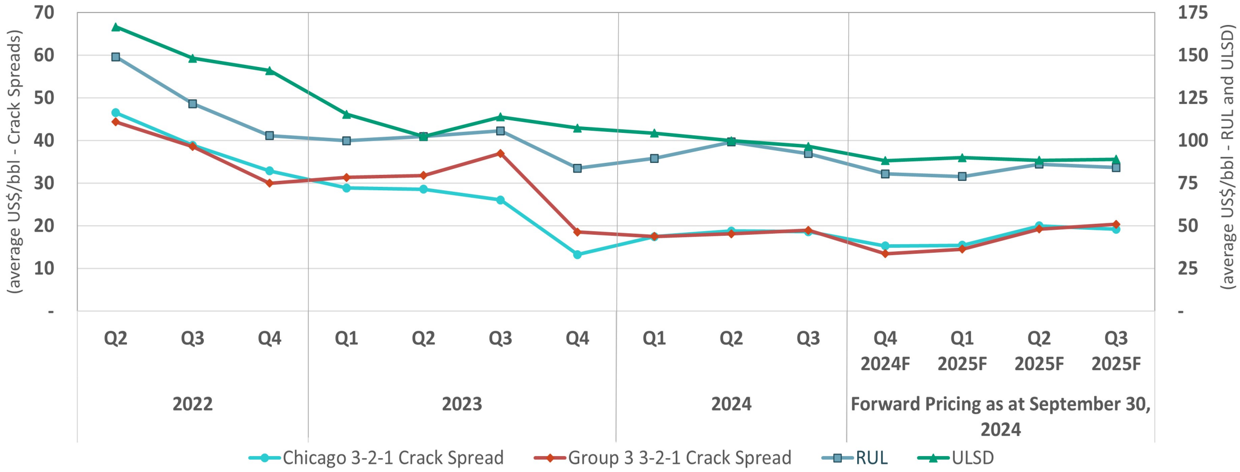
Refined product prices declined in the three and nine months ended September 30, 2024, compared with 2023, as incremental global capacity additions brought refinery crack spreads back to a range consistent with recent history. Additionally, U.S. refineries have operated at very high utilization rates for most of the nine months ended September 30, 2024, with the exception of some significant unplanned outages in PADD 2.

Average RINs costs were also lower in the three and nine months ended September 30, 2024, compared with the same periods of 2023, due to a decline in biofuel feedstock costs and increased renewable diesel production.

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 various other factors such as the quality and purchase location of crude oil feedstock, refinery configuration and product output, and the time lag between the purchase of feedstock and the product sale, as the feedstock 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, or the location we sell product; however, they are used as a general market indicator.

Refined Product Benchmarks



Natural Gas Benchmarks

In the three and nine months ended September 30, 2024, average NYMEX and AECO natural gas prices decreased compared with 2023, due to high production in the U.S. and the Western Canada Sedimentary Basin, and a mild winter leaving a surplus of inventory entering the summer storage injection season. AECO prices weakened further relative to NYMEX natural gas due to limited Western Canadian takeaway capacity. 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, 2024, on average, the Canadian dollar weakened relative to the U.S. dollar, compared with the same periods of 2023, positively impacting our reported revenues. The Canadian dollar weakened relative to the U.S. dollar as at September 30, 2024, compared with December 31, 2023, resulting in unrealized foreign exchange losses on the translation of our U.S. dollar debt.

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 months ended September 30, 2024, on average, the Canadian dollar weakened relative to RMB, compared with the same period 2023, positively impacting our reported revenues. In the nine months ended September 30, 2024, on average, the Canadian dollar strengthened slightly relative to RMB, compared with 2023.

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 finance costs, affect how certain liabilities are measured, and impact our cash flow and financial results.

As at September 30, 2024, the Bank of Canada's Policy Interest Rate was 4.25 percent. On October 23, 2024, the Bank of Canada reduced the overnight rate by 50 basis points to 3.75 percent.

OUTLOOK

Commodity Price Outlook

Global crude oil prices decreased in the third quarter of 2024, compared with the second quarter of 2024, as OPEC+ announced plans to unwind the production cuts that have supported prices. The current voluntary cuts have been extended to the end of November 2024 from the original end date of September 2024 with plans to gradually unwind voluntary cuts over 12 months starting December 2024. Non-OPEC+ supply growth, led by U.S. shale, has been robust and is expected to continue to grow for the remainder of 2024 and into 2025, though slowing U.S. drilling activity since 2023 has softened the expectations for U.S. supply growth modestly. Demand growth has continued but has been weaker than in 2023 due to lower than expected Chinese demand growth, which has also weighed on prices. Current geopolitical risks are causing volatility in global oil prices, with any escalation causing prices to rise and any de-escalation causing prices to settle. With planned production growth expected from OPEC+ due to the unwinding of production cuts, and high Middle East spare production capacity, geopolitical tensions are not impacting global oil prices as much as they would have in a tighter market.

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. 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 the strategic petroleum reserve, the crisis in Israel and Gaza including any spread to a wider conflict, Iran, attacks on vessels in the Red Sea, and tensions between Venezuela and Guyana. In addition, weakening global economic activity, inflation and interest rate uncertainty, and the potential for a recession remain a risk to the pace of demand growth.

Refined product prices have declined from elevated levels in 2022 and 2023 as a result of incremental global capacity additions and U.S. refineries operating at very high utilization rates.

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. As expected, the start-up of TMX in 2024 is having a narrowing impact on WTI-WCS differentials.
- We expect refined product prices 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 and globally.
- 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, although seasonal winter heating demand is expected to offer some support for natural gas prices. Weather will continue to be a key driver of demand and impact prices.
- We expect the Canadian dollar to continue to be impacted by 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, crude oil prices 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 integrated upstream and downstream operations help us to mitigate the impact of commodity price volatility. Crude oil production in our upstream assets is blended with condensate and butane and used as crude oil feedstock at our downstream operations, and condensate extracted from our blended crude oil is sold back to our Oil Sands operations.

Our refining capacity is focused in the U.S. Midwest, along with smaller exposures in the USGC and Alberta, exposing Cenovus to market crack spreads in 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 and spreads on refined products.
- Monitoring market fundamentals and optimizing run rates at our refineries accordingly.
- Traditional crude oil storage tanks in various geographic locations.

Key Priorities for 2024

Our 2024 priorities are focused on top-tier safety performance, returns to shareholders target, project execution, and a continued focus on cost and sustainability improvements.

Top-tier Safety Performance

Safe and reliable operations are our number one priority. We strive to ensure safe and reliable operations across our portfolio, and aim to be best-in-class operators for each of our major assets and businesses.

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. In July, we achieved our Net Debt target of $4.0 billion. As a result, we plan to steward Net Debt to $4.0 billion and return 100 percent of Excess Free Funds Flow to shareholders over time through share buybacks and/or variable dividends. For further details, see the Liquidity and Capital Resources section of this MD&A.

Project Execution

Investing in future growth is a focus for us, with several key projects in progress, including the West White Rose project, the Narrows Lake tie-back to Christina Lake, the Foster Creek optimization project and the Sunrise growth program. In addition, we have a number of information system upgrades underway in 2024. The SeaRose ALE represents a key project that we completed at the dry dock. We plan to continue to execute these multi-year projects on time and on budget.

Cost Leadership

We aim to maximize shareholder value through continued focus on cost structures and margin optimization. We are focused on reducing operating, capital and general and administrative costs, realizing the full value of our integrated strategy while making decisions that support long-term value for Cenovus.

We will continue to target improved reliability of our downstream assets leveraging our upstream expertise to maximize the long-term profitability of our assets.

Sustainability

Sustainability is central to Cenovus's culture. We have established ambitious targets in our five environmental, social and governance ("ESG") focus areas and we continue to advance work to support progress against these targets.

We continue to support our commitment to the Pathways Alliance foundational project, including efforts to reach agreements with the federal and provincial governments that provide a sufficient level of fiscal support to progress large-scale carbon capture projects, while maintaining global competitiveness. It is critical that the federal and provincial governments provide support at a level consistent with what similar large-scale carbon capture projects are receiving globally to enable Canada to achieve its greenhouse gas ("GHG") emissions goals.

Additional information on Cenovus's performance in safety, Indigenous reconciliation, and inclusion and diversity is available in Cenovus's 2023 Corporate Social Responsibility report on our website at cenovus.com.

2024 Corporate Guidance

Our 2024 guidance, as updated on July 31, 2024, is available on our website at cenovus.com.

The following table is a sub-set of our full guidance for 2024:

	Capital Investment ($ millions)	**Production** (MBOE/d)	**Crude Oil Unit Throughput** (Mbbls/d)
Upstream			
Oil Sands	**2,500 - 2,750**	**600 - 610**	
Conventional	**350 - 425**	**120 - 125**	
Offshore	**850 - 950**	**65 - 75**	
Upstream Total	**3,700 - 4,125**	**785 - 810**	
Downstream	**750 - 850**		**640 - 670**
Corporate and Eliminations	**60 - 70**		

Full year guidance for total capital investment is between $4.5 billion to $5.0 billion. This includes $3.0 billion directed towards sustaining production and supporting continued safe and reliable operations, and between $1.5 billion and $2.0 billion in optimization and growth capital.

REPORTABLE SEGMENTS

UPSTREAM

Oil Sands

In the third quarter of 2024, we:

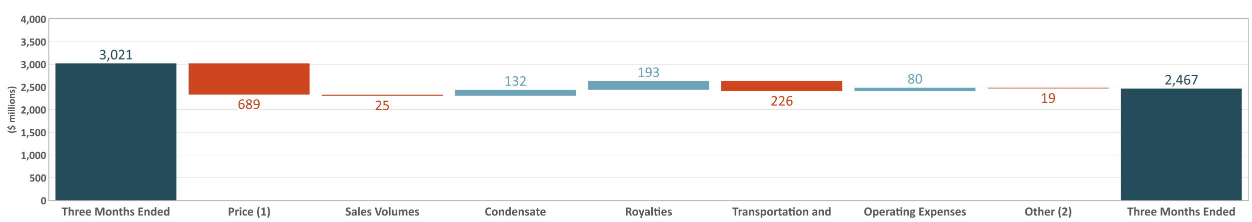
- Delivered safe and reliable operations including the safe execution of the turnaround at Christina Lake which was completed ahead of schedule.
- Produced 585.9 thousand barrels of crude oil per day (2023 – 601.6 thousand barrels of crude oil per day).
- Brought two new well pads online as part of the Sunrise growth program.
- Delivered successful results from our sustaining, redevelopment and base well optimization programs.
- Generated Operating Margin of $2.5 billion, a decrease compared with the third quarter of 2023, primarily due to lower realized sales prices.
- Invested capital of $681 million primarily for sustaining activities and growth projects.
- Averaged a Netback of $45.16 per BOE (2023 – $54.78 per BOE).

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2024**	2023	**2024**	2023
Gross Sales				
External Sales	**5,456**	5,645	**16,525**	15,654
Intersegment Sales	**1,719**	1,926	**4,831**	4,061
	7,175	7,571	**21,356**	19,715
Royalties	**(889)**	(1,082)	**(2,400)**	(2,218)
Revenues	**6,286**	6,489	**18,956**	17,497
Expenses				
Purchased Product	**629**	462	**1,321**	1,231
Transportation and Blending	**2,579**	2,324	**8,265**	7,965
Operating	**621**	688	**1,896**	2,101
Realized (Gain) Loss on Risk Management	**(10)**	(6)	**23**	(7)
Operating Margin	**2,467**	3,021	**7,451**	6,207
Unrealized (Gain) Loss on Risk Management	**(1)**	47	**(13)**	44
Depreciation, Depletion and Amortization	**784**	785	**2,330**	2,230
Exploration Expense	**2**	—	**6**	4
(Income) Loss from Equity-Accounted Affiliates	**—**	—	**(14)**	6
Segment Income (Loss)	**1,682**	2,189	**5,142**	3,923

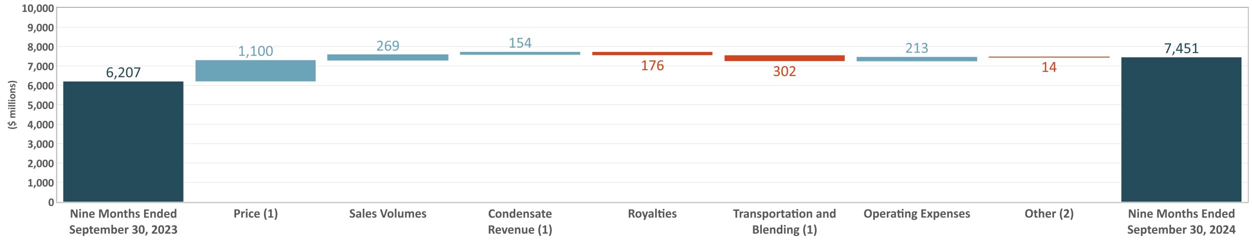
Operating Margin Variance

Three Months Ended September 30, 2024



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

Nine Months Ended September 30, 2024



(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) 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,	
	2024	2023	**2024**	2023
Total Sales Volumes [1] (MBOE/d)	**595.3**	597.2	**596.3**	584.1
Realized Sales Price [2] ($/BOE)	**81.77**	94.45	**81.01**	74.08
Crude Oil Production by Asset (Mbbls/d)				
Foster Creek	**198.0**	189.3	**196.3**	182.1
Christina Lake	**211.8**	237.6	**228.4**	236.6
Sunrise	**50.4**	54.5	**48.4**	48.6
Lloydminster Thermal	**109.4**	104.6	**112.3**	103.3
Lloydminster Conventional Heavy Oil	**16.3**	15.6	**17.4**	16.5
Total Crude Oil Production [3] (Mbbls/d)	**585.9**	601.6	**602.8**	587.1
Natural Gas [4] (MMcf/d)	**10.4**	10.6	**10.9**	12.0
Total Production (MBOE/d)	**587.7**	603.4	**604.8**	589.0
Effective Royalty Rate [5] (percent)				
Foster Creek	**25.9**	23.4	**24.0**	22.9
Christina Lake	**27.7**	33.2	**26.2**	29.8
Sunrise	**7.0**	5.6	**6.2**	5.4
Lloydminster [6]	**14.3**	8.5	**10.9**	8.7
Total Effective Royalty Rate	**22.4**	22.6	**20.4**	21.1
Transportation and Blending Expense [7] ($/BOE)	**9.18**	7.41	**8.89**	8.16
Operating Expense [7] ($/BOE)	**11.17**	12.56	**11.50**	13.09
Per-Unit DD&A [7] ($/BOE)	**13.62**	12.96	**13.53**	12.90

(1) Bitumen, heavy crude oil and natural gas.
(2) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(3) Oil Sands production is primarily bitumen, except for Lloydminster conventional heavy oil, which is heavy crude oil.
(4) Conventional natural gas product type.
(5) Effective royalty rates are equal to royalty expense divided by product revenue, net of transportation expenses, excluding realized (gain) loss on risk management.
(6) Composed of Lloydminster thermal and Lloydminster conventional heavy oil assets.
(7) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Revenues

Gross sales decreased for the three months ended September 30, 2024, compared with 2023, due to lower WTI benchmark prices and widening of the WTI-WCS differential at Hardisty. Gross sales increased for the nine months ended September 30, 2024, compared with 2023, due to a narrowing of the WTI-WCS differential at Hardisty and increased sales volumes.

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.

For the three and nine months ended September 30, 2024, approximately 38 percent and 31 percent, respectively (2023 – approximately 25 percent) of our crude oil sales volumes were sold outside of Alberta. In the same periods, approximately 25 percent and 20 percent, respectively, of our Oil Sands crude oil sales volumes were sold to our Canadian and U.S. downstream operations.

Our realized sales price decreased quarter-over-quarter mainly due to lower WTI benchmark prices and wider WTI-WCS and condensate-WCS differentials. The year-over-year increase in realized sales price was mainly due to narrower WTI-WCS and condensate-WCS differentials with relatively consistent WTI prices.

Cenovus makes storage and transportation decisions to use our marketing and transportation infrastructure, including storage and pipeline assets, in order 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.

Production Volumes

In the three and nine months ended September 30, 2024, Oil Sands crude oil production was 585.9 thousand barrels per day and 602.8 thousand barrels per day, respectively (2023 – 601.6 thousand barrels per day and 587.1 thousand barrels per day, respectively). The quarter-over-quarter decrease was mainly due to turnaround activity at our Christina Lake asset in September 2024. The year-over-year increase was mainly due to increases at our Foster Creek and Lloydminster assets, partially offset by a decrease at Christina Lake as discussed.

Production at Foster Creek increased in the three and nine months ended September 30, 2024, compared with 2023. The increases were primarily due to successful results from our redevelopment and sustaining programs, base well optimizations, and a turnaround in the second quarter of 2023.

Production at Christina Lake decreased in the three and nine months ended September 30, 2024, compared with 2023. The decreases were primarily due to the turnaround in September 2024, partially offset by successful results from redevelopment and sustaining programs, as well as base well optimizations.

Production from our Lloydminster thermal assets increased in the three and nine months ended September 30, 2024, compared with 2023. The increases were primarily due to successful results from the 2023 redevelopment program and base well optimizations.

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 one percent of product revenues and the post-payout calculation is based on 20 percent of operating margin. 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, 2024, Oil Sands royalties were $889 million and $2.4 billion, respectively, (2023 – $1.1 billion and $2.2 billion, respectively). The quarter-over-quarter decrease was primarily due to lower realized pricing combined with lower sales volumes. The year-over-year increase was primarily due to higher realized pricing coupled with higher sales volumes. For the three months ended September 30, 2024, the Oil Sands effective royalty rate decreased primarily due to lower realized prices combined with lower Alberta sliding scale oil sands royalty rates, compared with 2023. For the nine months ended September 30, 2024, the Oil Sands effective royalty rate decreased primarily due to annual adjustments on the end-of-period filings, partially offset by higher realized prices and higher Alberta sliding scale oil sands royalty rates, compared with 2023.

Expenses

Transportation and Blending

In the third quarter of 2024, blending expenses increased $132 million due to the use of higher priced condensate, partially offset by lower sales volumes, compared with 2023. In the first nine months of 2024, blending expenses increased $149 million compared with 2023, due to higher sales volumes.

Transportation expenses increased in the three and nine months ended September 30, 2024, due to higher sales volumes exported to destinations outside of Alberta, which includes transportation costs related to our use of TMX, and increased tariff costs due to increased sales outside of Alberta, compared with 2023.

Per-Unit Transportation Expenses (1)

	Three Months Ended September 30,		Nine Months Ended September 30,	
($/BOE)	**2024**	2023	**2024**	2023
Foster Creek	**12.90**	10.55	**12.58**	12.20
Christina Lake	**7.63**	5.76	**6.69**	6.46
Sunrise	**15.36**	12.29	**17.41**	12.49
Lloydminster (2)	**3.63**	3.29	**4.02**	3.54
Total Oil Sands	**9.18**	7.41	**8.89**	8.16

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

Per-unit transportation expenses increased in the three and nine months ended September 30, 2024, compared with the same periods in 2023, primarily due to higher transportation expenses discussed above.

At Foster Creek, per-unit transportation expenses increased in the three months ended September 30, 2024, primarily due to higher costs as we increased our use of TMX, partially offset by lower rail transportation costs, compared with 2023. For the nine months ended September 30, 2024, per-unit transportation expenses increased due to the reasons noted above, partially offset by higher sales volumes. In the three and nine months ended September 30, 2024, volumes sold to destinations outside of Alberta increased to 66 percent and 50 percent, respectively (2023 – 44 percent and 46 percent, respectively).

At Christina Lake, per-unit transportation expenses increased for both periods primarily due to higher sales to U.S. destinations, increased tariff rates and decreased sales volumes, partially offset by lower rail costs. In the three and nine months ended September 30, 2024, volumes shipped to U.S. destinations increased to 24 percent and 19 percent, respectively (2023 – 14 percent and 17 percent, respectively).

At Sunrise in the three and nine months ended September 30, 2024, per-unit transportation expenses increased primarily due to increased sales outside of Alberta through the use of TMX, compared with 2023. In the three and nine months ended September 30, 2024, sales outside of Alberta increased to 88 percent and 92 percent, respectively (2023 – 51 percent and 49 percent, respectively). This was partially offset by higher sales volumes in both periods.

At Lloydminster, per-unit transportation expenses increased in the three and nine months ended September 30, 2024, primarily due to higher tariff rates for sales outside of Alberta, compared with 2023. We shipped one percent and four percent, respectively, to U.S. destinations, compared with no sales in 2023. This was partially offset by higher sales volumes in both periods.

Operating

Primary drivers of our operating expenses in the first nine months of 2024 were fuel, repairs and maintenance, and workforce. Total operating expenses decreased due to lower fuel costs as a result of significant declines in AECO benchmark prices in the three and nine months ended September 30, 2024, compared with 2023. The decreases were partially offset by higher repairs and maintenance costs and GHG compliance costs. We have experienced some inflationary pressures on our costs; however, we manage our costs by securing long-term contracts, working with vendors and purchasing long-lead items to mitigate future cost escalations.

Per-Unit Operating Expenses [(1)]

($/BOE)	Three Months Ended September 30, 2024	Percent Change	2023	Nine Months Ended September 30, 2024	Percent Change	2023
Foster Creek						
Fuel	**1.52**	**(46)**	2.83	**2.24**	**(40)**	3.76
Non-Fuel	**7.49**	**(7)**	8.08	**7.72**	**(6)**	8.24
Total	**9.01**	**(17)**	10.91	**9.96**	**(17)**	12.00
Christina Lake						
Fuel	**1.41**	**(51)**	2.87	**2.05**	**(35)**	3.13
Non-Fuel	**7.92**	**23**	6.45	**6.72**	**18**	5.71
Total	**9.33**	**—**	9.32	**8.77**	**(1)**	8.84
Sunrise						
Fuel	**1.81**	**(56)**	4.13	**2.95**	**(41)**	4.98
Non-Fuel	**11.16**	**(6)**	11.81	**11.24**	**(15)**	13.18
Total	**12.97**	**(19)**	15.94	**14.19**	**(22)**	18.16
Lloydminster [(2)]						
Fuel	**1.74**	**(59)**	4.25	**2.71**	**(42)**	4.69
Non-Fuel	**15.17**	**(4)**	15.82	**14.88**	**(9)**	16.42
Total	**16.91**	**(16)**	20.07	**17.59**	**(17)**	21.11
Total Oil Sands						
Fuel	**1.55**	**(52)**	3.24	**2.32**	**(39)**	3.79
Non-Fuel	**9.62**	**3**	9.32	**9.18**	**(1)**	9.30
Total	**11.17**	**(11)**	12.56	**11.50**	**(12)**	13.09

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

Per-unit fuel expenses decreased overall due to lower natural gas prices, as discussed above.

Foster Creek per-unit non-fuel expenses decreased in the three and nine months ended September 30, 2024, compared with 2023. The quarter-over-quarter decrease was due to lower repairs and maintenance and electricity costs, partially offset by increased workover activity and lower sales volumes. The year-over-year decrease was due to higher sales volumes and lower electricity costs, partially offset by increased workover activity and GHG compliance costs.

Christina Lake per-unit non-fuel expenses increased in the three and nine months ended September 30, 2024, compared with 2023, due to turnaround activity combined with decreased sales volumes.

Sunrise per-unit non-fuel expenses decreased in the three and nine months ended September 30, 2024, compared with 2023, mainly due to lower electricity costs and increased sales volumes, partially offset by increased repairs and maintenance costs.

Lloydminster per-unit non-fuel expenses decreased in the three and nine months ended September 30, 2024, compared with 2023. The decreases for both periods were due to increased sales volumes combined with lower chemical costs, partially offset by increased GHG compliance costs.

Netbacks [(1)]

($/BOE)	Three Months Ended September 30, 2024	2023	Nine Months Ended September 30, 2024	2023
Sales Price	**81.77**	94.45	**81.01**	74.08
Royalties	**16.26**	19.70	**14.68**	13.91
Transportation and Blending	**9.18**	7.41	**8.89**	8.16
Operating Expenses	**11.17**	12.56	**11.50**	13.09
Netback	**45.16**	54.78	**45.94**	38.92

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

Conventional

In the third quarter of 2024, we:

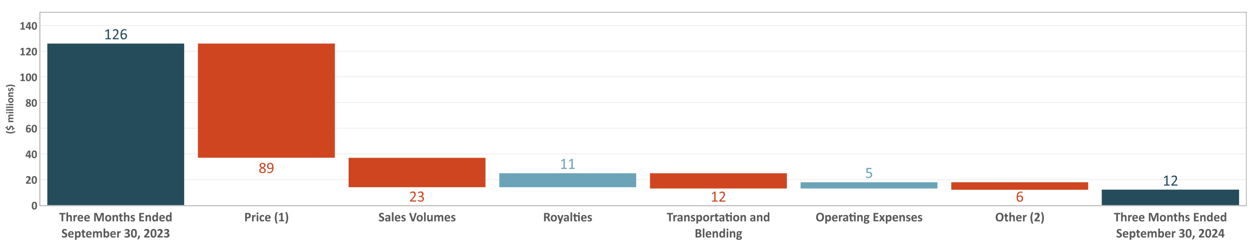
- Delivered safe and reliable operations including safely executing turnarounds during the period.
- Produced 118.1 thousand BOE per day (2023 – 127.2 thousand BOE per day).
- Generated Operating Margin of $12 million, a decrease of $114 million from the third quarter of 2023, primarily due to lower natural gas benchmark prices.
- Invested capital of $106 million with a continued focus on drilling, completion, tie-in and infrastructure projects.
- Averaged a Netback of $1.12 per BOE (2023 – $9.66 per BOE).

Financial Results

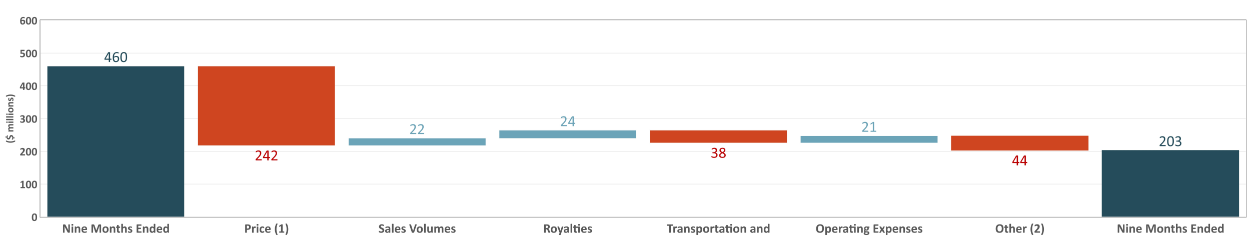
	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2024**	2023	**2024**	2023
Gross Sales				
External Sales	**225**	285	**866**	1,160
Intersegment Sales	**488**	525	**1,417**	1,307
	713	810	**2,283**	2,467
Royalties	**(15)**	(27)	**(61)**	(85)
Revenues	**698**	783	**2,222**	2,382
Expenses				
Purchased Product	**459**	438	**1,353**	1,258
Transportation and Blending	**80**	73	**241**	220
Operating	**147**	150	**432**	444
Realized (Gain) Loss on Risk Management	**—**	(4)	**(7)**	—
Operating Margin	**12**	126	**203**	460
Unrealized (Gain) Loss on Risk Management	**2**	7	**10**	(14)
Depreciation, Depletion and Amortization	**109**	104	**330**	286
(Income) Loss From Equity-Accounted Affiliates	**—**	—	**1**	—
Segment Income (Loss)	**(99)**	15	**(138)**	188

Operating Margin Variance

Three Months Ended September 30, 2024



Nine Months Ended September 30, 2024



(1) Changes to price include the impact of realized risk management gains and losses.
(2) Reflects Operating Margin from processing facilities.

Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	**2024**	2023
Total Sales Volumes (MBOE/d)	**118.1**	127.2	**120.5**	118.5
Realized Sales Price [1] ($/BOE)	**20.42**	28.13	**25.18**	32.70
Light Crude Oil ($/bbl)	**93.68**	105.43	**93.18**	104.19
NGLs ($/bbl)	**53.77**	47.74	**55.84**	47.52
Conventional Natural Gas ($/Mcf)	**1.53**	3.05	**2.43**	4.19
Production by Product				
Light Crude Oil (Mbbls/d)	**4.6**	6.3	**5.0**	5.8
NGLs (Mbbls/d)	**21.1**	23.9	**21.5**	21.3
Conventional Natural Gas (MMcf/d)	**554.8**	582.1	**564.8**	548.8
Total Production (MBOE/d)	**118.1**	127.2	**120.5**	118.5
Conventional Natural Gas Production (percentage of total)	**78**	76	**78**	77
Crude Oil and NGLs Production (percentage of total)	**22**	24	**22**	23
Effective Royalty Rate [2] (percent)	**10.7**	9.6	**10.9**	10.7
Transportation Expense [3] ($/BOE)	**5.15**	3.82	**5.03**	3.97
Operating Expense [3] ($/BOE)	**12.77**	12.36	**12.35**	13.26
Per-Unit DD&A [3] ($/BOE)	**9.97**	8.82	**9.89**	8.77

(1) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Effective royalty rates are equal to royalty expense divided by product revenue, net of transportation expenses, excluding realized (gain) loss on risk management.
(3) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Revenues

For the three and nine months ended September 30, 2024, gross sales were $713 million and $2.3 billion, respectively (2023 – $810 million and $2.5 billion, respectively). The quarter-over-quarter decrease was due to decreased benchmark pricing and lower sales volumes. The year-over-year decrease was primarily due to decreased benchmark pricing, partially offset by increased sales volumes.

Price

Our total realized sales price decreased primarily due to lower natural gas benchmark prices. For the three and nine months ended September 30, 2024, the AECO benchmark price declined 73 percent and 47 percent, respectively, compared with 2023.

Production Volumes

Production volumes decreased quarter-over-quarter due to turnaround activities and the divestiture of non-core assets in 2024. Production volumes increased year-over-year primarily due to the successful restart of operations following wildfire activity in 2023, partially offset by the divestiture of non-core assets as discussed.

Royalties

The Conventional assets are subject to royalty regimes in Alberta and British Columbia. Royalties decreased in the three and nine months ended September 30, 2024, compared with 2023, primarily due to lower natural gas benchmark prices and the divestiture of non-core assets as discussed above.

Expenses

Transportation

Our transportation expenses 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 three and nine months ended September 30, 2024, transportation expenses and per-unit transportation expenses increased primarily due to increased tariff rates, compared with 2023.

Operating

Primary drivers of operating expenses in the first nine months of 2024 were repairs and maintenance, workforce and property tax costs. In the three and nine months ended September 30, 2024, total operating expenses decreased compared with 2023, primarily due to the divestiture of non-core assets and lower electricity costs, partially offset by increased repairs and maintenance costs related to turnaround activity in the quarter. Per-unit operating expenses increased in the three months ended September 30, 2024, compared with 2023, primarily due to lower sales volumes, partially offset by the factors above. Per-unit operating expenses decreased in the nine months ended September 30, 2024, due to the factors discussed above and higher sales volumes, compared with 2023.

Netbacks [1]

	Three Months Ended September 30,		Nine Months Ended September 30,	
($/BOE)	**2024**	2023	**2024**	2023
Sales Price	**20.42**	28.13	**25.18**	32.70
Royalties	**1.38**	2.29	**1.86**	2.64
Transportation and Blending	**5.15**	3.82	**5.03**	3.97
Operating Expenses	**12.77**	12.36	**12.35**	13.26
Netback	**1.12**	9.66	**5.94**	12.83

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

Offshore

In the third quarter of 2024, we:

- Delivered safe and reliable operations.
- Produced 65.5 thousand BOE per day of light crude oil, NGLs and natural gas (2023 – 66.4 thousand BOE per day).
- Generated Operating Margin of $252 million, a decrease of $48 million from the third quarter of 2023, primarily due to lower sales volumes.
- Averaged a Netback of $53.20 per BOE (2023 – $57.87 per BOE).
- Invested capital of $355 million, mainly related to the progression of the West White Rose project and SeaRose ALE project.

In late December 2023, we suspended production at the White Rose field as we prepared for the planned SeaRose ALE project. Refit work that commenced in the first quarter of 2024 was completed at the dry dock. The SeaRose FPSO is currently en route to the White Rose field, where reconnecting and commissioning activities will take place. Production is expected to resume around year-end.

We continue to progress the West White Rose project which was approximately 85 percent complete as at September 30, 2024. Since our decision in 2022 to restart the project, we have invested approximately $1.3 billion. First oil is expected in 2026.

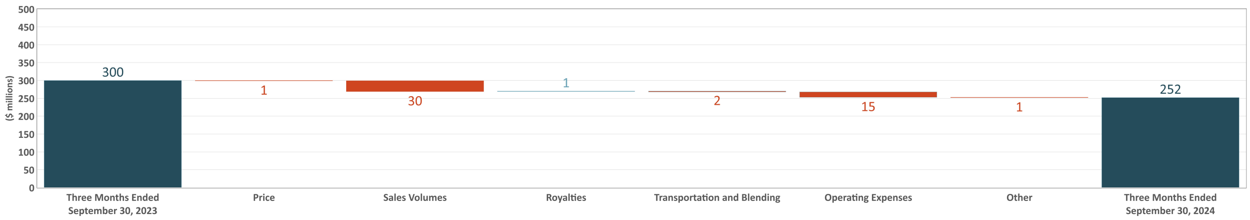
Financial Results

	Three Months Ended September 30,					
	2024			2023		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore**	Atlantic	Asia Pacific	Offshore
Gross Sales						
External Sales	**71**	**300**	**371**	78	324	402
Intersegment Sales	**—**	**—**	**—**	—	—	—
	71	**300**	**371**	78	324	402
Royalties	**(1)**	**(24)**	**(25)**	(2)	(24)	(26)
Revenues	**70**	**276**	**346**	76	300	376
Expenses						
Transportation and Blending	**2**	**—**	**2**	—	—	—
Operating	**58**	**34**	**92**	47	29	76
Operating Margin [1]	**10**	**242**	**252**	29	271	300
Depreciation, Depletion and Amortization			**134**			130
Exploration Expense			**42**			2
(Income) Loss from Equity-Accounted Affiliates			**(11)**			(11)
Segment Income (Loss)			**87**			179

(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, 2024



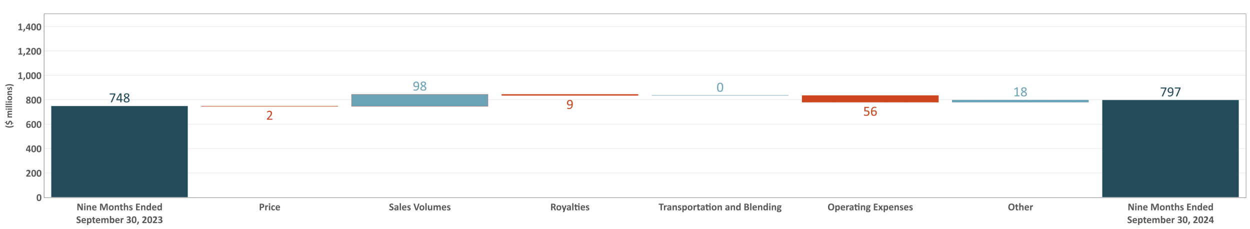
Financial Results

	Nine Months Ended September 30,					
	2024			2023		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore**	Atlantic	Asia Pacific	Offshore
Gross Sales						
External Sales	**264**	**935**	**1,199**	232	871	1,103
Intersegment Sales	**—**	**—**	**—**	—	—	—
	264	**935**	**1,199**	232	871	1,103
Royalties	**(2)**	**(72)**	**(74)**	(11)	(54)	(65)
Revenues	**262**	**863**	**1,125**	221	817	1,038
Expenses						
Transportation and Blending	**9**	**—**	**9**	9	—	9
Operating	**225**	**94**	**319**	190	91	281
Operating Margin (1)	**28**	**769**	**797**	22	726	748
Depreciation, Depletion and Amortization			**421**			349
Exploration Expense			**50**			6
(Income) Loss from Equity-Accounted Affiliates			**(34)**			(29)
Segment Income (Loss)			**360**			422

(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, 2024



Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	**2024**	2023
Sales Volumes				
Atlantic (Mbbls/d)	**7.2**	7.8	**8.6**	7.8
Asia Pacific (MBOE/d)				
China	**40.5**	43.8	**42.6**	39.4
Indonesia (1)	**16.0**	13.7	**14.8**	14.1
Total Asia Pacific	**56.5**	57.5	**57.4**	53.5
Total Sales Volumes (MBOE/d)	**63.7**	65.3	**66.0**	61.3
Realized Sales Price (1) (2) ($/BOE)	**77.28**	79.27	**78.95**	79.42
Atlantic - Light Crude Oil ($/bbl)	**106.56**	107.99	**111.21**	108.48
Asia Pacific (1) ($/BOE)	**73.55**	75.38	**74.09**	75.18
NGLs ($/bbl)	**98.35**	101.97	**99.15**	95.36
Conventional Natural Gas ($/Mcf)	**11.37**	11.43	**11.39**	11.70
Production by Product				
Atlantic - Light Crude Oil (Mbbls/d)	**9.0**	8.9	**8.2**	7.7
Asia Pacific (1)				
NGLs (Mbbls/d)	**9.9**	11.7	**10.7**	10.6
Conventional Natural Gas (MMcf/d)	**279.4**	274.7	**280.1**	257.3
Total Asia Pacific (MBOE/d)	**56.5**	57.5	**57.4**	53.5
Total Production (MBOE/d)	**65.5**	66.4	**65.6**	61.2
Effective Royalty Rate (3) (percent)				
Atlantic	**1.0**	2.4	**0.6**	4.6
Asia Pacific (1)	**8.7**	9.8	**8.6**	10.0
Operating Expense (2) ($/BOE)	**17.97**	14.66	**19.36**	17.37
Atlantic (4)	**88.40**	65.91	**93.74**	78.61
Asia Pacific (1) (2)	**8.98**	7.73	**8.15**	8.42
Per-Unit DD&A (4) ($/BOE)	**22.16**	26.29	**22.51**	26.00

(1) Reported sales volumes, associated per-unit values and royalty rates reflect Cenovus's 40 percent interest in HCML. The HCML joint venture is accounted for using the equity method in the interim Consolidated Financial Statements.
(2) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(3) Effective royalty rates are equal to royalty expense divided by product revenue, net of transportation expenses, excluding realized (gain) loss on risk management.
(4) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Revenues

For the three months ended September 30, 2024, gross sales decreased compared with 2023, due to lower sales volumes and a decrease in realized sales price due to lower Brent benchmark pricing. For the nine months ended September 30, 2024, gross sales increased compared with 2023, due to an increase in sales volumes.

Price

Our Atlantic realized sales price on light crude oil decreased in the three months ended September 30, 2024, primarily due to lower Brent benchmark pricing, compared with 2023. Our Atlantic realized sales price on light crude oil increased in the nine months ended September 30, 2024, due to slightly higher Brent benchmark pricing, compared with 2023. The prices we receive for natural gas sold in Asia Pacific are set under long-term contracts.

Production Volumes

For the three months ended September 30, 2024, Atlantic production was relatively consistent, compared with 2023. For the nine months ended September 30, 2024, Atlantic production increased compared with 2023, primarily due to resuming production at the Terra Nova FPSO in November 2023, partially offset by the suspension of production at the White Rose field in December 2023 for the SeaRose ALE project. Light crude oil production from the White Rose and Terra Nova fields are offloaded from the SeaRose FPSO and the Terra Nova FPSO, respectively, to tankers and stored at an onshore terminal before shipment to buyers, which results in a timing difference between production and sales.

For the three months ended September 30, 2024, Asia Pacific production decreased compared with 2023, due to planned maintenance in China, partially offset by higher gas production at the MAC field in Indonesia. For the nine months ended September 30, 2024, Asia Pacific production increased compared with 2023, due to the temporary unplanned outage that occurred in the second quarter of 2023, related to the disconnection of the umbilical by a third-party vessel, and production from the MAC field discussed above.

Royalties

In the three and nine months ended September 30, 2024, Atlantic royalties were $1 million and $2 million, respectively (2023 – $2 million and $11 million, respectively). Year-over-year royalties were lower due to lower royalty rates combined with a credit received in the second quarter of 2024 for the 2023 White Rose annual royalty filing.

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 Asia Pacific for the three and nine months ended September 30, 2024, declined compared with 2023. The quarter-over-quarter decrease was primarily due to lower sales volumes in China. The year-over-year decrease was primarily due to a production bonus paid to the Government of Indonesia for achieving a production milestone in the first quarter of 2023, partially offset by a consumption tax implemented in China in June 2023.

Expenses

Transportation

Transportation expenses include the costs of transporting crude oil from the Terra Nova and SeaRose FPSO units to onshore terminals via tankers, as well as storage costs. Transportation expenses in the three and nine months ended September 30, 2024, were $2 million and $9 million, respectively (2023 – $nil and $9 million, respectively).

Operating

Primary drivers of our Atlantic operating expenses in the first nine months of 2024 were repairs and maintenance, costs related to vessels and air services, and workforce. For the three and nine months ended September 30, 2024, operating expenses increased compared with 2023. The increase is primarily due to increased repairs and maintenance costs. The year-over-year increase was also impacted by higher costs related to vessels and air services, partially offset by costs related to the restart of the West White Rose project during the first nine months of 2023. Per-unit operating expenses increased in the three and nine months ended September 30, 2024, compared with 2023, mainly due to the same factors discussed above.

Primary drivers of our China operating expenses in the first nine months of 2024 were repairs and maintenance, insurance and workforce costs. In the three months ended September 30, 2024, operating expenses and per-unit operating expenses increased, compared with 2023, primarily due to increased repairs and maintenance costs. Per-unit operating expenses also increased due to lower sales volumes. In the nine months ended September 30, 2024, operating expenses increased primarily due to higher insurance and workforce costs, partially offset by lower repairs and maintenance costs. Per-unit operating expenses decreased, compared with 2023, due to increased sales volumes, partially offset by higher operating expenses.

In the three months ended September 30, 2024, Indonesia per-unit operating expenses decreased compared with 2023, due to increased sales volumes, partially offset by increased operating expenses from the operations at the MAC field that was fully operational in the third quarter of 2023. Per-unit operating expenses were relatively consistent in the nine months ended September 30, 2024, compared with 2023.

Netbacks [(1)]

($/BOE, except where indicated)	**Three Months Ended September 30, 2024** Atlantic ($/bbl)	China	Indonesia	Total Offshore [(2)]
Sales Price	**106.56**	**80.52**	**55.93**	**77.28**
Royalties	**1.03**	**6.31**	**6.54**	**5.77**
Transportation and Blending	**3.00**	**—**	**—**	**0.34**
Operating Expenses	**88.40**	**8.20**	**10.95**	**17.97**
Netback	**14.13**	**66.01**	**38.44**	**53.20**

($/BOE, except where indicated)	Three Months Ended September 30, 2023 Atlantic ($/bbl)	China	Indonesia	Total Offshore [(2)]
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

($/BOE, except where indicated)	**Nine Months Ended September 30, 2024** Atlantic ($/bbl)	China	Indonesia	Total Offshore [(2)]
Sales Price	**111.21**	**80.22**	**56.47**	**78.95**
Royalties	**0.65**	**6.17**	**6.94**	**5.62**
Transportation and Blending	**3.70**	**—**	**—**	**0.48**
Operating Expenses	**93.74**	**7.22**	**10.83**	**19.36**
Netback	**13.12**	**66.83**	**38.70**	**53.49**

($/BOE, except where indicated)	Nine Months Ended September 30, 2023 Atlantic ($/bbl)	China	Indonesia	Total Offshore [(2)]
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

(1) Contains 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. The HCML joint venture is accounted for using the equity method in the interim Consolidated Financial Statements.

DOWNSTREAM

Canadian Refining

In the third quarter of 2024, we:

- Delivered safe and reliable operations.
- Returned the Upgrader to full operations following the second quarter turnaround.
- Had throughput of 99.4 thousand barrels per day and crude unit utilization of 92 percent (2023 – 108.4 thousand barrels per day and 100 percent, respectively).
- Generated an Operating Margin of $60 million (2023 – $170 million).
- Invested capital of $44 million.

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions, except where indicated)	**2024**	2023	**2024**	2023
Gross Sales				
External Sales	**1,482**	1,544	**3,682**	3,997
Intersegment Sales	**98**	261	**365**	679
Revenues	**1,580**	1,805	**4,047**	4,676
Purchased Product	**1,353**	1,480	**3,415**	3,656
Gross Margin (1)	**227**	325	**632**	1,020
Expenses				
Operating	**167**	155	**759**	471
Operating Margin	**60**	170	**(127)**	549
Depreciation, Depletion and Amortization	**49**	50	**147**	136
Segment Income (Loss)	**11**	120	**(274)**	413

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

Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions, except where indicated)	**2024**	2023	**2024**	2023
Operable Capacity (1) (Mbbls/d)	**108.0**	108.0	**108.0**	108.0
Total Processed Inputs (Mbbls/d)	**106.4**	114.7	**91.4**	107.7
Crude Oil Unit Throughput (Mbbls/d)	**99.4**	108.4	**85.8**	100.8
Crude Unit Utilization (2) (percent)	**92**	100	**79**	93
Total Production (Mbbls/d)	**113.6**	122.4	**98.0**	114.6
Synthetic Crude Oil	**47.3**	53.2	**38.4**	47.9
Asphalt	**16.5**	15.7	**15.4**	15.6
Diesel	**11.8**	13.8	**10.0**	12.8
Other	**32.5**	34.1	**29.1**	33.4
Ethanol	**5.5**	5.6	**5.1**	4.9
Refining Margin (3) ($/bbl)	**20.63**	27.57	**22.42**	31.31

(1) Operable capacity is the capacity based on barrels per calendar day. It is the amount of input that a distillation facility can process under usual operating conditions. We previously reported crude oil name plate capacity.
(2) Crude unit utilization is calculated as crude oil unit throughput divided by operable capacity. Prior periods have been re-presented to align with this calculation.
(3) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A. Revenues from the Upgrader, commercial fuels business and the Lloydminster Refinery for the three and nine months ended September 30, 2024, were $1.5 billion and $3.8 billion, respectively (2023 – $1.7 billion and $4.4 billion, respectively).

Overall, our Canadian Refining assets delivered reliable operations for the nine months ended September 30, 2024. Throughput was lower in the three and nine months ended September 30, 2024, compared with 2023, primarily due to the turnaround at the Upgrader that ran from May 8 to July 4, 2024, and the ramp-up to full operations that followed.

Revenues, Gross Margin and Refining 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 are seasonal and increase during paving season, which typically runs from May through October each year.

The Upgrader and Lloydminster Refinery source crude oil feedstock from our Oil Sands segment. In the three and nine months ended September 30, 2024, approximately 14 percent and 11 percent, respectively, of total crude oil sales volumes from our Oil Sands assets were sold to our Canadian Refining segment (three and nine months ended September 30, 2023 – 15 percent and 14 percent, respectively).

Revenues have decreased compared with 2023, due to decreased synthetic crude oil and diesel benchmark prices combined with lower refined product production.

Gross Margin and Refining Margin decreased in the three and nine months ended September 30, 2024, compared with 2023, primarily due to lower synthetic crude oil and diesel benchmark prices, combined with lower refined product production, as discussed above. In the quarter, Gross Margin and Refining Margin were also impacted by the adverse effect of processing feedstock purchased at higher prices in prior periods. Year to date, decreases were partially offset by lower feedstock costs.

Operating Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions, except where indicated)	**2024**	2023	**2024**	2023
Operating Expenses - Upgrading and Refining (1)	**143**	129	**667**	385
Operating Expenses - Turnaround Costs	**24**	1	**250**	1
Per-Unit Operating Expenses (1) (2) ($/bbl)	**14.63**	12.23	**26.65**	13.10
Per-Unit Operating Expenses - Turnaround Costs (2)	**2.41**	0.12	**9.98**	0.06

(1) Inclusive of turnaround costs. Represents operating expenses associated with the Lloydminster Upgrader, the Lloydminster Refinery and the commercial fuels business.
(2) Specified financial measure. Per-unit metrics are calculated on total processed inputs. Changes in metrics from prior periods have been re-presented. See the Specified Financial Measures Advisory of this MD&A.

Primary drivers of operating expenses were turnaround costs, workforce costs and repairs and maintenance.

In the three and nine months ended September 30, 2024, operating expenses increased compared with 2023, primarily due to costs associated with the Upgrader turnaround. The increase in operating expenses, combined with decreased total processed inputs, resulted in increased per-unit operating expenses, compared with 2023.

U.S. Refining

In the third quarter of 2024, we:

- Delivered safe operations.
- Commenced a significant turnaround at the Lima Refinery. The turnaround was safely completed in late October.
- Had crude throughput of 543.5 thousand barrels per day (2023 – 555.9 thousand barrels per day) and crude unit utilization of 89 percent (2023 – 91 percent).
- Recorded a negative Operating Margin of $383 million primarily due to lower market crack spreads, the adverse effect of processing higher priced feedstock purchased in prior periods, higher operating expenses and reliability issues at our operated and non-operated assets.
- Invested capital of $153 million, primarily focused on sustaining activities at our operated assets and refining reliability projects at our non-operated assets.

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions, except where indicated)	**2024**	2023	**2024**	2023
Gross Sales				
External Sales	**7,644**	7,836	**22,794**	19,524
Intersegment Sales	**4**	17	**7**	22
Revenues	**7,648**	7,853	**22,801**	19,546
Purchased Product	**7,284**	6,467	**20,540**	16,729
Gross Margin (1)	**364**	1,386	**2,261**	2,817
Expenses				
Operating	**751**	623	**2,045**	1,904
Realized (Gain) Loss on Risk Management	**(4)**	11	**5**	6
Operating Margin	**(383)**	752	**211**	907
Unrealized (Gain) Loss on Risk Management	**5**	(2)	**3**	(13)
Depreciation, Depletion and Amortization	**115**	109	**338**	314
Segment Income (Loss)	**(503)**	645	**(130)**	606

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

Operating Results

($ millions, except where indicated)	Three Months Ended September 30, 2024	2023	Nine Months Ended September 30, 2024	2023
Operable Capacity (Mbbls/d)	**612.3**	612.3	**612.3**	612.3
Total Processed Inputs (Mbbls/d)	**568.0**	576.6	**579.0**	472.7
Crude Oil Unit Throughput (Mbbls/d)	**543.5**	555.9	**554.5**	453.3
Heavy Crude Oil	**215.7**	210.6	**219.9**	165.4
Light/Medium Crude Oil	**327.8**	345.3	**334.6**	287.9
Crude Unit Utilization (1) (2) (percent)	**89**	91	**91**	78
Total Production (Mbbls/d)	**571.6**	583.6	**585.3**	475.2
Gasoline	**259.7**	267.6	**273.4**	218.3
Distillates (3)	**205.3**	196.1	**206.7**	165.2
Asphalt	**29.6**	24.7	**28.0**	19.2
Other	**77.0**	95.2	**77.2**	72.5
Refining Margin (4) ($/bbl)	**6.97**	26.13	**14.25**	21.83
Weighted Average Crack Spread, Net of RINs (5) (US$/bbl)	**14.79**	20.75	**14.60**	21.13
Weighted Average Crack Spread, Net of RINs (5) (C$/bbl)	**20.18**	27.81	**19.87**	28.44
Market Capture (2) (4) (6) (percent)	**35**	94	**72**	77

(1) Crude unit utilization is calculated as crude oil unit throughput divided by operable capacity. Prior periods have been re-presented to align with this calculation.
(2) The Superior Refinery's operable capacity is included in the metrics effective April 1, 2023. The Toledo Refinery includes a weighted average operable capacity in the metrics, as full ownership of the Toledo Refinery was acquired on February 28, 2023.
(3) Includes diesel and jet fuel.
(4) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(5) Weighted average crack spread, net of RINs is calculated as Cenovus's operable capacity-weighted average of the Chicago and Group 3 3-2-1 benchmark market crack spreads net of RINs. Average foreign exchange rates per period are used in the conversion to Canadian dollars.
(6) The definition of Market Capture is Refining Margin divided by the weighted average crack spread, net of RINs, expressed as a percentage.

In the third quarter of 2024, we commenced a significant turnaround at the Lima Refinery. The turnaround started in early September and was successfully completed in late October. The turnaround decreased throughput and refined product production and increased operating expenses in the quarter compared with 2023. We were able to partially mitigate the impact of the Lima turnaround on production by processing intermediate products at our Toledo Refinery, which allowed the Lima crude unit to continue operations.

Throughput and refined product production were also impacted by unplanned outages at our refineries.

Year-to-date U.S. Refining throughput and refined product production increased compared with 2023, primarily due to full operations from the Toledo Acquisition, and the restart of the Superior Refinery in 2023. This increase was partially offset by the factors discussed above.

Revenues

Revenues decreased in the third quarter of 2024, primarily due to declines in benchmark gasoline and diesel prices of between 13 percent and 15 percent, compared with 2023.

Revenues increased $3.3 billion in the nine months ended September 30, 2024, compared with 2023, due to higher sales volumes, partially offset by lower refined product pricing. Average benchmark gasoline and diesel prices decreased nine percent, compared with 2023.

Gross Margin and Market Capture

Market crack spreads do not precisely mirror the configuration and product output of our refineries, or the location we sell product; 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. Some of 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.

Gross Margin decreased in the three months ended September 30, 2024, compared with 2023, primarily due to lower market crack spreads, combined with the adverse effect of processing higher priced feedstock purchased in prior periods. The Chicago 3-2-1 crack spread decreased 29 percent, and the Group 3 crack spread decreased 49 percent, compared with 2023. The Gross Margin decrease was partially offset by the widening of the WTI-WCS differential at Hardisty. These factors, slightly offset by the decrease in total processed inputs compared with 2023, also impacted our Refining Margin.

Gross Margin decreased in the nine months ended September 30, 2024, primarily due to the reasons discussed above, combined with the narrowing of the WTI-WCS differential at Hardisty. The Chicago 3-2-1 crack spread decreased 34 percent, and the Group 3 crack spread decreased 45 percent, compared with 2023. These factors, combined with the increase in total processed inputs, also impacted our Refining Margin.

Market Capture is the Refining Margin, calculated on a FIFO basis of accounting, generated as a percentage of the weighted average market crack spread, net of RINs. The Chicago and Group 3 3-2-1 market crack spreads are used to calculate Market Capture as they are relevant for our refining assets, with a heavier weighting towards Chicago 3-2-1.

In the three and nine months ended September 30, 2024, Market Capture decreased compared with 2023. The decrease was primarily due to the adverse effect of processing higher priced feedstock purchased in prior periods. Year to date, Market Capture was also impacted by the narrowing of the WTI-WCS differential at Hardisty, as discussed above.

Operating Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions, except where indicated)	**2024**	2023	**2024**	2023
Operating Expenses (1)	**751**	623	**2,045**	1,904
Operating Expenses - Turnaround Costs	**85**	23	**177**	65
Per-Unit Operating Expenses (1) (2) ($/bbl)	**14.37**	11.74	**12.89**	14.76
Per-Unit Operating Expenses - Turnaround Costs (2)	**1.63**	0.43	**1.12**	0.51

(1) Operating expenses are inclusive of turnaround costs.
(2) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Primary drivers of operating expenses were repairs and maintenance, workforce and turnaround costs.

In the three and nine months ended September 30, 2024, operating expenses increased primarily due to turnaround activities. Year to date, operating expenses increased, mainly as a result of the Toledo Acquisition, partially offset by a decrease in repairs and maintenance expenses.

Per-unit operating expenses increased in the three months ended September 30, 2024, primarily due to higher operating expenses, as discussed above, combined with lower total processed inputs. Per-unit operating expenses decreased in the nine months ended September 30, 2024, compared with 2023, primarily due to higher total processed inputs, partially offset by higher operating expenses, as discussed above.

CORPORATE AND ELIMINATIONS

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2024**	2023	**2024**	2023
Realized (Gain) Loss on Risk Management	**(13)**	(1)	**(10)**	2
Unrealized (Gain) Loss on Risk Management	**1**	20	**31**	71
General and Administrative	**172**	292	**593**	617
Finance Costs, Net (1)	**118**	73	**394**	393
Integration, Transaction and Other Costs	**41**	12	**113**	49
Foreign Exchange (Gain) Loss, Net	**(73)**	133	**81**	7
(Gain) Loss on Divestiture of Assets (1)	**(17)**	—	**(121)**	22
Re-measurement of Contingent Payments	**—**	67	**30**	83
Other (Income) Loss, Net	**(28)**	(22)	**(158)**	(42)

(1) Revised presentation as of January 1, 2024. Refer to Note 3 of the interim Consolidated Financial Statements for further detail.

General and Administrative

Primary drivers of our general and administrative expenses in the first nine months of 2024 were workforce costs, long-term incentive costs, and information technology related costs. General and administrative expenses included a non-cash stock-based compensation recovery of $12 million in the third quarter of 2024 (2023 – costs of $151 million) and year-to-date costs of $123 million (2023 – $196 million).

Finance Costs, Net

Finance costs were higher compared with 2023, primarily due a discount on redemption of long-term debt of $84 million recorded in the third quarter of 2023, partially offset by lower interest expenses on long-term debt in 2024. Refer to the Liquidity and Capital Resources section of this MD&A for further details on long-term debt.

The annualized weighted average interest rate on outstanding debt for the three and nine months ended September 30, 2024, was 4.54 percent and 4.50 percent, respectively (2023 – 4.67 percent and 4.70 percent, respectively).

Integration, Transaction and Other Costs

In the three and nine months ended September 30, 2024, we incurred costs of $41 million and $113 million, respectively, related to modernizing and replacing certain information technology systems, optimizing business processes and standardizing data across the Company.

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

Foreign Exchange (Gain) Loss, Net

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2024**	2023	**2024**	2023
Unrealized Foreign Exchange (Gain) Loss	**(108)**	59	**101**	(99)
Realized Foreign Exchange (Gain) Loss	**35**	74	**(20)**	106
	(73)	133	**81**	7

Unrealized foreign exchange gains and losses were primarily due to the translation of U.S. denominated debt. Realized foreign exchange gains and losses were primarily related to working capital. As at September 30, 2024, the Canadian dollar strengthened relative to the US dollar at June 30, 2024 and weakened relative to December 31, 2023.

(Gain) Loss on Divestiture of Assets

The Company closed a transaction with Athabasca Oil Corporation to create Duvernay Energy Corporation, in which we hold a 30 percent interest, and recorded a before-tax gain of $65 million on the transaction.

The Company also closed the sale of non-core assets in its Conventional segment in 2024 for net proceeds of $40 million and recorded a before-tax gain of $52 million.

Re-measurement of Contingent Payments

On August 31, 2024, the variable payment obligation associated with the transaction with BP Canada Energy Group ULC to purchase the remaining 50 percent interest in Sunrise Oil Sands Partnership ended. For the nine months ended September 30, 2024, the Company made payments of $261 million for the quarterly payment periods ending November 30, 2023, February 29, 2024, and May 31, 2024.

As at September 30, 2024, $40 million was included in accounts payable and accrued liabilities representing the final amount owing under this agreement. The final payment was made in October 2024.

Other (Income) Loss, Net

For the nine months ended September 30, 2024, other income was primarily related to the receipt of insurance proceeds for the Toledo Refinery.

Income Taxes

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2024**	2023	**2024**	2023
Current Tax				
Canada	**184**	484	**830**	941
United States	**—**	4	**2**	4
Asia Pacific	**57**	68	**157**	152
Other International	**9**	7	**26**	19
Total Current Tax Expense (Recovery)	**250**	563	**1,015**	1,116
Deferred Tax Expense (Recovery)	**(46)**	(2)	**(124)**	(416)
	204	561	**891**	700

For the nine months ended September 30, 2024, we recorded current tax expense related to operations in all jurisdictions in which we operate. The decrease in current tax expense was due to lower earnings compared with the same period in 2023. The effective tax rate in the first nine months of 2024 was 22.9 percent (2023 – 17.2 percent). The lower effective tax rate in the first nine months of 2023 reflects the impact of the step-up in the tax basis on the Toledo Acquisition.

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 preserve our balance sheet, provide flexibility in both high and low commodity price environments, and deliver value to shareholders. The framework enables a shift to pay 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 Ratings, Morningstar DBRS and Fitch Ratings. The cost and availability of borrowing and access to sources of liquidity and capital are dependent on current credit ratings and market conditions.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2024**	2023	**2024**	2023
Cash From (Used In)				
Operating Activities	**2,474**	2,738	**7,206**	4,442
Investing Activities	**(1,308)**	(1,101)	**(3,613)**	(4,015)
Net Cash Provided (Used) Before Financing Activities	**1,166**	1,637	**3,593**	427
Financing Activities	**(1,175)**	(2,600)	**(2,764)**	(3,674)
Effect of Foreign Exchange on Cash and Cash Equivalents	**(41)**	58	**48**	(15)
Increase (Decrease) in Cash and Cash Equivalents	**(50)**	(905)	**877**	(3,262)

	September 30,	December 31,
As at ($ millions)	**2024**	2023
Cash and Cash Equivalents	**3,104**	2,227
Total Debt	**7,300**	7,287

Cash From (Used in) Operating Activities

For the three months ended September 30, 2024, cash from operating activities decreased compared with 2023, primarily due to lower Operating Margin, partially offset by changes in non-cash working capital. Changes in non-cash working capital increased cash from operating activities by $588 million primarily due to lower accounts receivable and inventories, partially offset by lower accounts payable.

For the nine months ended September 30, 2024, cash from operating activities increased compared with 2023, primarily due to changes in non-cash working capital, partially offset by lower Operating Margin. In the first nine months of 2023, changes in non-cash working capital decreased cash from operating activities by $2.1 billion, primarily driven by an income tax payment of $1.2 billion, that occurred during the period.

Cash From (Used in) Investing Activities

Cash used in investing activities increased in the third quarter of 2024, due to a planned increase in capital investment compared with 2023.

Cash used in investing activities decreased in the first nine months of 2024 compared with 2023, due to the Toledo Acquisition in the first quarter of 2023, partially offset by a planned increase in capital investment.

Cash From (Used in) Financing Activities

Cash used in financing activities decreased in the three and nine months ended September 30, 2024, compared with the same periods in 2023. The decreases were primarily due to the purchase of US$1.0 billion of unsecured notes in the third quarter of 2023. The decrease for the nine months ended September 30, 2024, was partially offset by higher cash returns to common shareholders of $2.5 billion compared with $2.0 billion in the same period of 2023.

Working Capital

Working capital as at September 30, 2024, was $3.8 billion (December 31, 2023 – $3.5 billion). The increase in working capital was driven by an increase in cash, partially offset by a decrease in receivables and an increase in accounts payable.

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

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. In July 2024, we achieved our Net Debt target of $4.0 billion. This represents a Net Debt to Adjusted Funds Flow ratio target of approximately 1.0 times at the bottom of the commodity pricing cycle, which we believe is approximately US$45.00 per barrel.

In accordance with our shareholder return framework, we plan to steward Net Debt to $4.0 billion and return 100 percent of Excess Free Funds to shareholders over time by way of share buybacks and/or variable dividends. Working capital movements and other factors may result in periods where shareholder returns are less than, or exceed, Excess Free Funds Flow, and Net Debt is above or below our target. The allocation of Excess Free Funds Flow to shareholder returns may be accelerated, deferred or reallocated between quarters at management's discretion.

Cenovus returned $732 million through share buybacks, $586 million more than Excess Free Funds Flow generated in the third quarter of 2024. As at September 30, 2024, Net Debt was $4.2 billion.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2024**	2023	**2024**	2023
Excess Free Funds Flow (1)	**146**	1,989	**1,713**	1,995
Target Return (2)	**146**	995	**930**	998
Purchase of Common Shares Under NCIB	**732**	361	**1,337**	711
Payment for Purchase of Warrants	**—**	600	**—**	600
Variable Dividends Paid	**—**	—	**251**	—
Return Amount (Above) Below Target	**(586)**	34	**(658)**	(313)

(1) *Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.*
(2) *Target return for the nine months ended September 30, 2024, includes 100 percent of Excess Free Funds Flow in the third quarter and 50 percent of Excess Free Funds Flow in the first and second quarters of 2024. Target return for the three and nine months ended September 30, 2023, was 50 percent of Excess Free Funds Flow.*

Short-Term Borrowings

There were no direct borrowings on our uncommitted demand facilities as at September 30, 2024, or December 31, 2023. As at September 30, 2024, the Company's proportionate share drawn on the WRB uncommitted demand facilities was US$75 million (C$101 million) (December 31, 2023 – US$135 million (C$179 million)).

Long-Term Debt, Including Current Portion

Long-term debt, including the current portion, as at September 30, 2024, was $7.2 billion (December 31, 2023 – $7.1 billion). This includes U.S. dollar denominated unsecured notes of US$3.8 billion (C$5.1 billion) (December 31, 2023 – US$3.8 billion (C$5.0 billion)) and Canadian dollar denominated unsecured notes of $2.0 billion (December 31, 2023 – $2.0 billion).

As at September 30, 2024, 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, 2024:

($ millions)	Maturity	Amount Available
Cash and Cash Equivalents	**n/a**	**3,104**
Committed Credit Facility (1)		
Revolving Credit Facility – Tranche A	**June 26, 2028**	**3,300**
Revolving Credit Facility – Tranche B	**June 26, 2027**	**2,200**
Uncommitted Demand Facilities		
Cenovus Energy Inc. (2)	**n/a**	**1,060**
WRB (3)	**n/a**	**202**

(1) As at September 30, 2024, no amount was drawn on the credit facility (December 31, 2023 – $nil).

(2) Represents amounts available for cash draws. 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, 2024, there were outstanding letters of credit aggregating to $375 million (December 31, 2023 – $364 million) and no direct borrowings (December 31, 2023 – $nil).

(3) Represents Cenovus's proportionate share of US$225 million available to cover short-term working capital requirements. As at September 30, 2024, US$75 million (C$101 million) of this capacity was drawn (December 31, 2023 – US$135 million (C$179 million)).

On June 26, 2024, Cenovus renewed its existing committed credit facility to extend the maturity dates by more than one year. The committed credit facility consists of a $2.2 billion tranche maturing on June 26, 2027, and a $3.3 billion tranche maturing on June 26, 2028. As at September 30, 2024, no amount was drawn on the credit facility (December 31, 2023 – $nil).

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 below this limit.

Base Shelf Prospectus

We have a base shelf prospectus that allows us to offer, from time to time, debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere as permitted by law. The base shelf prospectus will expire in December 2025. Offerings under the base shelf prospectus are subject to market conditions on terms set forth in one or more prospectus supplements.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, Total Debt, the Net Debt to Adjusted EBITDA ratio, the Net Debt to Adjusted Funds Flow ratio and the Net Debt to Capitalization ratio. Refer to Note 12 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 Shareholder's 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, 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, (gain) loss on divestiture of assets, re-measurement of contingent payments 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, 2024	December 31, 2023
Net Debt to Adjusted EBITDA Ratio (times)	**0.4**	0.5
Net Debt to Adjusted Funds Flow Ratio (times)	**0.5**	0.6
Net Debt to Capitalization Ratio (percent)	**12**	15

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$45.00 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 Adjusted Funds Flow ratio and Net Debt to Adjusted EBITDA ratio as at September 30, 2024, decreased compared with December 31, 2023, as a result of lower 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.

Our Net Debt to Capitalization ratio as at September 30, 2024, decreased compared with December 31, 2023, primarily due to lower Net Debt.

Share Capital and Stock-Based Compensation Plans

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

As at September 30, 2024, there were approximately 1,829.5 million common shares outstanding (December 31, 2023 – 1,871.9 million common shares) and 36 million preferred shares outstanding (December 31, 2023 – 36 million preferred shares). Refer to Note 16 of the interim Consolidated Financial Statements for further details.

As at September 30, 2024, there were approximately 3.8 million Cenovus Warrants outstanding (December 31, 2023 – 7.6 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 16 of the interim Consolidated Financial Statements for further details.

Refer to Note 18 of the interim Consolidated Financial Statements for further details on our stock option plans and our performance share unit, restricted share unit and deferred share unit plans. Our outstanding share data is as follows:

As at October 28, 2024	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**1,827,096**	**n/a**
Cenovus Warrants	**3,804**	**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	**9,057**	**5,145**
Other Stock-Based Compensation Plans	**17,094**	**1,736**

Common Share Dividends

In the third quarter of 2024, we paid base dividends of $329 million or $0.180 per common share (2023 – $264 million or $0.140 per common share). In the first nine months of 2024, we paid base dividends of $925 million or $0.500 per common share (2023 – $729 million or $0.385 per common share).

On October 30, 2024, the Board of Directors declared a fourth quarter base dividend of $0.180 per common share. The dividend is payable on December 31, 2024, to common shareholders of record as at December 13, 2024.

No variable dividend was declared or paid in the third quarters of 2024 or 2023. In the second quarter of 2024, we paid variable dividends of $251 million or $0.135 per common share.

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

Cumulative Redeemable Preferred Share Dividends

For the three and nine months ended September 30, 2024, dividends of $9 million and $27 million, respectively, were paid on the series 1, 2, 3, 5 and 7 preferred shares (2023 – $nil and $27 million, respectively). On October 30, 2024, the Board declared a fourth quarter dividend on the series 1, 2, 3, 5 and 7 preferred shares for a total of $9 million, payable on December 31, 2024, to preferred shareholders of record as at December 13, 2024.

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

Share Repurchases

We have an NCIB program to purchase up to 133.2 million common shares from November 9, 2023, to November 8, 2024.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2024	2023	**2024**	2023
Common Shares Purchased and Cancelled Under NCIB (millions of common shares)	**28.4**	13.8	**51.2**	29.4
Weighted Average Price per Common Share ($)	**25.22**	26.18	**25.60**	24.19
Purchase of Common Shares Under NCIB ($ millions)	**732**	361	**1,337**	711

From October 1, 2024, to October 28, 2024, the Company purchased an additional 2.5 million common shares for $59 million. As at October 28, 2024, the Company can further purchase up to 68.9 million common shares under the NCIB.

On October 30, 2024, the Company 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 127 million common shares under the NCIB program for a period of twelve months from the date the program is renewed.

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 from our total commitments disclosed below. For further information, see Note 23 to the interim Consolidated Financial Statements.

Our total commitments were $27.4 billion as at September 30, 2024 (December 31, 2023 – $28.8 billion), of which $24.3 billion are for various transportation and storage commitments and $62 million are for product purchase commitments. Transportation commitments include $843 million that are subject to regulatory approval, or were approved, but are not yet in service. Terms are up to 20 years on commencement and should help align with the Company's future transportation requirements.

As at September 30, 2024, our total commitments included commitments with HMLP of $1.9 billion related to long-term transportation and storage commitments.

As at September 30, 2024, outstanding letters of credit issued as security for performance under certain contracts totaled $375 million (December 31, 2023 – $364 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 40 percent interest in the jointly controlled entity HCML. The Company's share of equity investment income (loss) related to the joint venture are recorded in (income) loss from equity-accounted affiliates.

For the nine months ended September 30, 2024, the Company received $68 million of distributions from HCML (2023 – $61 million) and paid $nil in contributions (2023 – $31 million).

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 nine months ended September 30, 2024, we charged HMLP $116 million for construction and management services (2023 – $112 million).

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. Payments for access fees and transportation and storage services are made based on rates contractually agreed to with HMLP. For the nine months ended September 30, 2024, we incurred costs of $207 million for the use of HMLP's pipeline systems, as well as for transportation and storage services (2023 – $205 million).

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 2023 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/or 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, 2023.

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, 2023.

Update to Accounting Policies

As of January 1, 2024, the Company updated its accounting policies to aggregate certain items presented in the Consolidated Statements of Comprehensive Income (Loss) to more appropriately reflect the integrated operations of the business. There were no re-measurements to balances. Certain historical disaggregated balances continue to be presented in Note 1 of the interim Consolidated Financial Statements.

The following presentation changes were made, with comparative periods being re-presented:

- Gross sales and royalties were aggregated and presented as ‘Revenues’.
- Purchased product and transportation and blending were aggregated and presented as ‘Purchased Product, Transportation and Blending’.
- Depreciation, depletion and amortization, and exploration expense were aggregated and presented as ‘Depreciation, Depletion, Amortization and Exploration Expense’.
- Finance costs and interest income were aggregated and presented as ‘Finance Costs, Net’.
- Revaluation (gain) loss and (gain) loss on divestiture of assets were aggregated and presented as ‘(Gain) Loss on Divestiture of Assets’.

New Accounting Standards and Interpretations Not Yet Adopted

On April 9, 2024, the IASB issued IFRS 18, *“Presentation and Disclosure in Financial Statements”* (“IFRS 18”), which will replace International Accounting Standard 1, *“Presentation of Financial Statements”*. IFRS 18 will establish a revised structure for the Consolidated Statements of Comprehensive Income (Loss) and improve comparability across entities and reporting periods.

IFRS 18 is effective for annual periods beginning on or after January 1, 2027. The standard is to be applied retrospectively, with certain transition provisions. The Company is currently evaluating the impact of adopting IFRS 18 on the Consolidated Financial Statements.

On May 30, 2024, the IASB issued amendments to IFRS 9, *“Financial Instruments”,* and IFRS 7, *“Financial Instruments: Disclosures”.* The amendments include clarifications on the derecognition of financial liabilities and the classification of certain financial assets. In addition, new disclosure requirements for equity instruments designated as fair value through other comprehensive income (loss) were added. The amendments are effective for annual periods beginning on or after January 1, 2026, and will be applied retrospectively. The Company is currently evaluating the impact of the amendments on the 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, 2024. 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, 2024.

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", "commit", "continue", "could", "estimate", "expect", "focus", "may", "objective", "opportunities", "plan", "position", "priority", "progress", "strive", "target", and "will", or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: our five strategic objectives; shareholder value and returns; safety; sustainability; our commitment to the Pathways Alliance foundational project; maximizing value; financial discipline; disciplined capital allocation; Free Funds Flow; cash flow volatility and stability; managing our balance sheet; liquidity; growth of our base business; capital investment; our 2024 corporate guidance; reducing costs; realizing the full value of our integrated business; reinvesting in our business; diversifying our portfolio; capitalizing on opportunities; Net Debt; allocating Excess Free Funds Flow; project execution; progression of our planned drilling program; bringing wells online; reliable operations; being best-in-class operators; maintaining a strong balance sheet; costs; margins; realizing the full value of our integrated business; long-term value for Cenovus; downstream reliability and profitability; in respect of the White Rose project, returning the SeaRose FPSO to the field, reconnecting and commissioning, resuming production and achieving first oil; progressing the Narrows Lake tie-back to Christina Lake; progressing the Foster Creek and Sunrise optimization projects; progressing information system upgrades; ramp up the use of TMX; our five ESG focus areas; variable payments; provision for income taxes; funding near-term cash requirements; credit ratings; meeting payment obligations; cash flow volatility and stability; Net Debt to Adjusted Funds Flow ratio; the Company's capital allocation framework; capitalizing on opportunities throughout the commodity price cycle; Net Debt to Adjusted EBITDA ratio; maintaining sufficient liquidity; financial resilience; liabilities from legal proceedings; transportation and storage commitments; and the Company's outlook for commodities and the Canadian dollar, the factors that affect such outlook, 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, and 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 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 its 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 realize the anticipated benefits of investments in information system upgrades in a timely manner or at all; 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 divestitures, 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 2024 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.

2024 guidance dated July 31, 2024, and available on cenovus.com, assumes: Brent prices of US$83.50 per barrel, WTI prices of US$79.00 per barrel; WCS of US$63.00 per barrel; Differential WTI-WCS of US$16.00 per barrel; AECO natural gas prices of $1.65 per Mcf; Chicago 3-2-1 crack spread of US$17.40 per barrel; and an exchange rate of $0.73 US$/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 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 divestitures; 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 ESG targets and ambitions and the commercial viability and scalability of ESG strategies and related technology and products; the development and execution of implementing strategies to meet ESG 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 remaining 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 the Company's outlook for 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 refining 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, 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 refining 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.

Except as required by applicable securities laws, Cenovus disclaims any intention or obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. 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 AND DEFINITIONS

Abbreviations

The following abbreviations and definitions are used in this document:

Crude Oil and NGLs		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
WCS	Western Canadian Select	MMcf/d	million cubic feet per day	MBOE/d	thousand barrels of oil equivalent per day
WTI	West Texas Intermediate			DD&A	depreciation, depletion and amortization
				ESG	environmental, social and governance
				GHG	greenhouse gas
				FPSO	Floating production, storage and offloading unit
				NCIB	normal course issuer bid
				AECO	Alberta Energy Company
				NYMEX	New York Mercantile Exchange
				OPEC	Organization of Petroleum Exporting Countries
				OPEC+	OPEC and a group of 11 non-OPEC members
				SAGD	steam-assisted gravity drainage
				USGC	U.S. Gulf Coast

Revision of Operational Metrics

Following changes to our downstream portfolio in recent years, we undertook a review of our downstream disclosures with the intent of enhancing the performance reporting of our refining operations and increasing comparability with peers. As a result of this review, commencing in June 2024, we introduced the following new, and/or revised, operational metrics to our Canadian Refining and our U.S. Refining segments. Comparative periods have been provided or recalculated where applicable.

- **Total processed inputs** is a new measure that reflects the overall inputs required to produce refined products in our refineries, and is used as the denominator in our per-unit measures, replacing crude oil unit throughput.
- **Market capture** is a new measure in our U.S. Refining segment that reflects Refining Margin generated as a percentage of the weighted average crack spread, net of RINs, on a FIFO basis of accounting. The weighted average crack spread, net of RINs is calculated on Cenovus's operable capacity-weighted average of the Chicago and Group 3 3-2-1 benchmark market crack spreads, net of RINs.
- **Operable capacity** is the capacity based on barrels per calendar day. It is the amount of input that a distillation facility can process under usual operating conditions. Operable capacity has replaced crude oil unit throughput capacity, which was based on barrels per stream day and represents the amount of input that a distillation facility can process under optimal crude and product slate conditions, with no allowance for downtime.
- **Crude unit utilization** is crude oil unit throughput divided by operable capacity, expressed as a percentage. Previously this measure was calculated using crude oil unit throughput capacity.

The table below details the operable capacity and crude oil unit throughput capacity as at December 31, 2023, and is provided to illustrate the magnitude of the revised metrics detailed above:

(Mbbls/d)	Canadian Refining	U.S. Refining
Operable Capacity	108.0	612.3
Crude Oil Unit Throughput Capacity	110.5	635.2

Definitions and reconciliations of certain Specified Financial Measures, such as Refining Margin, Market Capture, per-unit operating expenses and per-unit operating expenses – turnaround costs are included in the Specified Financial Measures section of this MD&A.

SPECIFIED FINANCIAL MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS Accounting Standards including Operating Margin, 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, Market Capture, Realized Sales Price, Offshore and Asia Pacific Per-Unit Operating Expenses, and Netbacks (including the total Netback 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 Accounting Standards. 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 the relevant period's MD&A for reconciliations of Operating Margin, Adjusted Funds Flow, Free Funds Flow, Excess Free Funds Flow, Realized Sales Price and Netbacks for prior period information from 2024 and 2023 that is not found below.

Non-GAAP Measures and Non-GAAP Ratios

Operating Margin

Operating Margin and Operating Margin by asset are non-GAAP financial measures, and Operating Margin for upstream or downstream operations 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.

Operating Margin

	Three Months Ended September 30,					
	2024	2023	**2024**	2023	**2024**	2023
($ millions)	**Upstream** [1]		**Downstream** [1]		**Total**	
Gross Sales						
External Sales	**6,052**	6,332	**9,126**	9,380	**15,178**	15,712
Intersegment Sales	**2,207**	2,451	**102**	278	**2,309**	2,729
	8,259	8,783	**9,228**	9,658	**17,487**	18,441
Royalties	**(929)**	(1,135)	**—**	—	**(929)**	(1,135)
Revenues	**7,330**	7,648	**9,228**	9,658	**16,558**	17,306
Expenses						
Purchased Product	**1,088**	900	**8,637**	7,947	**9,725**	8,847
Transportation and Blending	**2,661**	2,397	**—**	—	**2,661**	2,397
Operating	**860**	914	**918**	778	**1,778**	1,692
Realized (Gain) Loss on Risk Management	**(10)**	(10)	**(4)**	11	**(14)**	1
Operating Margin	**2,731**	3,447	**(323)**	922	**2,408**	4,369

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

	Nine Months Ended September 30,					
	2024	2023	**2024**	2023	**2024**	2023
($ millions)	**Upstream** [1]		**Downstream** [1]		**Total**	
Gross Sales						
External Sales	**18,590**	17,917	**26,476**	23,521	**45,066**	41,438
Intersegment Sales	**6,248**	5,368	**372**	701	**6,620**	6,069
	24,838	23,285	**26,848**	24,222	**51,686**	47,507
Royalties	**(2,535)**	(2,368)	**—**	—	**(2,535)**	(2,368)
Revenues	**22,303**	20,917	**26,848**	24,222	**49,151**	45,139
Expenses						
Purchased Product	**2,674**	2,489	**23,955**	20,385	**26,629**	22,874
Transportation and Blending	**8,515**	8,194	**—**	—	**8,515**	8,194
Operating	**2,647**	2,826	**2,804**	2,375	**5,451**	5,201
Realized (Gain) Loss on Risk Management	**16**	(7)	**5**	6	**21**	(1)
Operating Margin	**8,451**	7,415	**84**	1,456	**8,535**	8,871

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

Operating Margin by Asset

	Three Months Ended September 30, 2024			Nine Months Ended September 30, 2024		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore** [1]	**Atlantic**	**Asia Pacific**	**Offshore** [1]
Gross Sales	**71**	**300**	**371**	**264**	**935**	**1,199**
Royalties	**(1)**	**(24)**	**(25)**	**(2)**	**(72)**	**(74)**
Revenues	**70**	**276**	**346**	**262**	**863**	**1,125**
Expenses						
Transportation and Blending	**2**	**—**	**2**	**9**	**—**	**9**
Operating	**58**	**34**	**92**	**225**	**94**	**319**
Operating Margin	**10**	**242**	**252**	**28**	**769**	**797**

	Three Months Ended September 30, 2023			Nine Months Ended September 30, 2023		
($ millions)	Atlantic	Asia Pacific	Offshore [1]	Atlantic	Asia Pacific	Offshore [1]
Gross Sales	78	324	402	232	871	1,103
Royalties	(2)	(24)	(26)	(11)	(54)	(65)
Revenues	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.

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 operating non-cash working capital. Operating 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 operating 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 expenditures for acquisitions net of cash acquired, plus proceeds from, or payments related to, divestitures.

	Three Months Ended September 30,		Nine Months Ended September 30,		Twelve Months Ended December 31,
($ millions)	**2024**	2023	**2024**	2023	2023
Cash From (Used in) Operating Activities	**2,474**	2,738	**7,206**	4,442	7,388
(Add) Deduct:					
Settlement of Decommissioning Liabilities	**(74)**	(68)	**(170)**	(157)	(222)
Net Change in Non-Cash Working Capital	**588**	(641)	**813**	(2,142)	(1,193)
Adjusted Funds Flow	**1,960**	3,447	**6,563**	6,741	8,803
Capital Investment	**1,346**	1,025	**3,537**	3,128	4,298
Free Funds Flow	**614**	2,422	**3,026**	3,613	4,505
Add (Deduct):					
Base Dividends Paid on Common Shares	**(329)**	(264)	**(925)**	(729)	(990)
Dividends Paid on Preferred Shares	**(9)**	—	**(27)**	(27)	(36)
Settlement of Decommissioning Liabilities	**(74)**	(68)	**(170)**	(157)	(222)
Principal Repayment of Leases	**(74)**	(70)	**(219)**	(216)	(288)
Acquisitions, Net of Cash Acquired	**(4)**	(32)	**(19)**	(501)	(515)
Proceeds From Divestitures	**22**	1	**47**	12	12
Excess Free Funds Flow	**146**	1,989	**1,713**	1,995	2,466

Gross Margin, Refining Margin and Market Capture

Gross Margin is a non-GAAP financial measure and Refining Margin contains a non-GAAP financial measure. These measures are 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 from our refineries, Upgrader and commercial fuels business divided by total processed inputs. Commencing in June 2024, total processed inputs was updated as the denominator to better reflect the overall inputs required to produce refined products. Before June 30, 2024, comparative periods were calculated based on barrels of crude oil unit throughput. All comparative periods have been revised to conform with our current presentation.

Canadian Refining

	Three Months Ended September 30, 2024		
($ millions)	**Lloydminster Upgrader and Lloydminster Refinery Total**	**Other [(1)]**	**Total Canadian Refining [(2)]**
Revenues	**1,493**	**87**	**1,580**
Purchased Product	**1,292**	**61**	**1,353**
Gross Margin	**201**	**26**	**227**
Total Processed Inputs (Mbbls/d)	**106.4**		
Refining Margin ($/bbl)	**20.63**		

(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)	Three Months Ended September 30, 2023 Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Refining [2]
Revenues	1,690	115	1,805
Purchased Product	1,399	81	1,480
Gross Margin	291	34	325
Total Processed Inputs (Mbbls/d)	114.7		
Refining Margin ($/bbl)	27.57		

(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)	**Nine Months Ended September 30, 2024** **Lloydminster Upgrader and Lloydminster Refinery Total**	**Other [1]**	**Total Canadian Refining [2]**
Revenues	**3,807**	**240**	**4,047**
Purchased Product	**3,246**	**169**	**3,415**
Gross Margin	**561**	**71**	**632**
Total Processed Inputs (Mbbls/d)	**91.4**		
Refining Margin ($/bbl)	**22.42**		

(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)	Nine Months Ended September 30, 2023 Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Refining [2]
Revenues	4,358	318	4,676
Purchased Product	3,437	219	3,656
Gross Margin	921	99	1,020
Total Processed Inputs (Mbbls/d)	107.7		
Refining Margin ($/bbl)	31.31		

(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)	Three Months Ended March 31, 2024 Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Refining
Revenues	1,249	83	1,332
Purchased Product	1,024	63	1,087
Gross Margin	225	20	245
Total Processed Inputs (Mbbls/d)	108.8		
Refining Margin ($/bbl)	22.68		

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

	Three Months Ended December 31, 2023		
($ millions)	Lloydminster Upgrader and Lloydminster Refinery Total	Other (1)	Total Canadian Refining
Revenues	1,454	103	1,557
Purchased Product	1,197	66	1,263
Gross Margin	257	37	294
Total Processed Inputs (Mbbls/d)	105.1		
Refining Margin ($/bbl)	26.48		

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

	Twelve Months Ended December 31, 2023		
($ millions)	Lloydminster Upgrader and Lloydminster Refinery Total	Other (1)	Total Canadian Refining
Revenues	5,812	421	6,233
Purchased Product	4,634	285	4,919
Gross Margin	1,178	136	1,314
Total Processed Inputs (Mbbls/d)	107.1		
Refining Margin ($/bbl)	30.13		

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

U.S. Refining

Market Capture contains a non-GAAP financial measure and is used in our U.S. Refining segment to provide an indication of margin captured relative to what was available in the market based on widely-used benchmarks. We define Market Capture as Refining Margin divided by the weighted average 3-2-1 market benchmark crack, net of RINs, expressed as a percentage. The weighted average crack spread, net of RINs, is calculated on Cenovus's operable capacity-weighted average of the Chicago and Group 3 3-2-1 benchmark market crack spreads, net of RINs.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
($ millions)	**2024**	2023	**2024**	2023
Revenues (1)	**7,648**	7,853	**22,801**	19,546
Purchased Product (1)	**7,284**	6,467	**20,540**	16,729
Gross Margin	**364**	1,386	**2,261**	2,817
Total Processed Inputs (Mbbls/d)	**568.0**	576.6	**579.0**	472.7
Refining Margin ($/bbl)	**6.97**	26.13	**14.25**	21.83
Operable Capacity (Mbbls/d)	**612.3**	612.3	**612.3**	612.3
Operable Capacity by Regional Benchmark (percent)				
Chicago 3-2-1 Crack Spread Weighting	**81**	81	**81**	80
Group 3 3-2-1 Crack Spread Weighting	**19**	19	**19**	20
Benchmark Prices and Exchange Rate				
Chicago 3-2-1 Crack Spread (US$/bbl)	**18.62**	26.06	**18.27**	27.83
Group 3 3-2-1 Crack Spread (US$/bbl)	**18.95**	36.96	**18.19**	33.36
RINs (US$/bbl)	**3.89**	7.42	**3.65**	7.80
US$ per C$1 - Average	**0.733**	0.746	**0.735**	0.743
Weighted Average Crack Spread, Net of RINs ($/bbl)	**20.18**	27.81	**19.87**	28.44
Market Capture (2) (percent)	**35**	94	**72**	77

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) The Superior Refinery's operable capacity is included in Market Capture effective April 1, 2023. For the nine months ended September 30, 2023, Market Capture includes a weighted average operable capacity for the Toledo Refinery as full ownership was acquired on February 28, 2023.

($ millions)	Three Months Ended March 31, 2024	Three Months Ended December 31, 2023	Twelve Months Ended December 31, 2023
Revenues	7,235	6,847	26,393
Purchased Product	6,132	6,625	23,354
Gross Margin	1,103	222	3,039
Total Processed Inputs (Mbbls/d)	575.0	500.6	479.7
Refining Margin ($/bbl)	21.08	4.82	17.36
Operable Capacity (Mbbls/d)	612.3	612.3	612.3
Operable Capacity by Regional Benchmark (percent)			
Chicago 3-2-1 Crack Spread Weighting	81	81	82
Group 3 3-2-1 Crack Spread Weighting	19	19	18
Benchmark Prices and Exchange Rate			
Chicago 3-2-1 Crack Spread (US$/bbl)	17.45	13.24	24.19
Group 3 3-2-1 Crack Spread (US$/bbl)	17.50	18.55	29.66
RINs (US$/bbl)	3.68	4.77	7.04
US$ per C$1 - Average	0.741	0.734	0.741
Weighted Average Crack Spread, Net of RINs ($/bbl)	18.59	12.94	24.49
Market Capture (1) (percent)	113	37	71

(1) The Superior Refinery's operable capacity is included in Market Capture effective April 1, 2023. For the twelve months ended December 31, 2023, Market Capture includes a weighted average operable capacity for the Toledo Refinery as full ownership was acquired on February 28, 2023.

Netback Reconciliations and Realized Sales Price

Netback is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring operating performance. Our Netback calculation is substantially aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook. Netback is defined as gross sales less royalties, transportation and blending, and operating expenses. 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. Condensate or butane (diluent) is blended with crude oil to transport it to market. In March 2024, modifications were made to our netback definition to enhance the clarity of certain costs captured in this metric. These modifications resulted in minor adjustments that are captured in the netback calculation on a prospective basis.

Realized Sales Price contains a non-GAAP measure. It includes our gross sales, purchased diluent costs and profit from optimization activities, such as cogeneration, third-party processing and trading. Offshore and Asia Pacific Per-Unit Operating Expenses contain non-GAAP measures. Offshore and Asia Pacific operating expenses, as used in the basis of our netback calculation, reflect our 40 percent interest in HCML. The HCML joint venture is accounted for using the equity method in the interim Consolidated Financial Statements. Netback per barrel of oil equivalent contains a non-GAAP measure. Netbacks per BOE reflect our margin on a per-barrel of oil equivalent basis. Per-unit measures are divided by sales volumes.

The following tables provide a reconciliation of Netback to Operating Margin found in our interim Consolidated Financial Statements.

Oil Sands

Three Months Ended September 30, 2024 ($ millions)	Foster Creek	Christina Lake	Sunrise	Lloydminster Oil Sands (1)	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
	Basis of Netback Calculation						
Gross Sales	1,494	1,622	416	939	**4,471**	—	**4,471**
Royalties	(329)	(406)	(23)	(131)	**(889)**	—	**(889)**
Revenues	1,165	1,216	393	808	**3,582**	—	**3,582**
Expenses							
Purchased Product	—	—	—	—	**—**	—	**—**
Transportation and Blending	227	156	77	42	**502**	—	**502**
Operating	159	190	64	197	**610**	—	**610**
Netback	779	870	252	569	**2,470**	—	**2,470**
Realized (Gain) Loss on Risk Management							**(10)**
Operating Margin							**2,480**

Three Months Ended September 30, 2024 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced	Other (2)	Total Oil Sands (3)
Gross Sales	**4,471**	2,021	548	135	**7,175**
Royalties	**(889)**	—	—	—	**(889)**
Revenues	**3,582**	2,021	548	135	**6,286**
Expenses					
Purchased Product	**—**	—	548	81	**629**
Transportation and Blending	**502**	2,021	—	56	**2,579**
Operating	**610**	—	—	11	**621**
Netback	**2,470**	—	—	(13)	**2,457**
Realized (Gain) Loss on Risk Management	**(10)**	—	—	—	**(10)**
Operating Margin	**2,480**	—	—	(13)	**2,467**

(1) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.
(2) Other includes construction, transportation and blending.
(3) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Three Months Ended September 30, 2023 ($ millions)	Foster Creek	Christina Lake	Sunrise	Lloydminster Oil Sands (1)	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
	Basis of Netback Calculation						
Gross Sales	1,798	1,936	456	998	**5,188**	1	**5,189**
Royalties	(375)	(603)	(22)	(81)	**(1,081)**	(1)	**(1,082)**
Revenues	1,423	1,333	434	917	**4,107**	—	**4,107**
Expenses							
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**

Three Months Ended September 30, 2023 ($ millions)	Basis of Netback Calculation	Adjustments			
	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)**
Revenues	**4,107**	1,889	398	95	**6,489**
Expenses					
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**

(1) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.
(2) Other includes construction, transportation and blending.
(3) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Nine Months Ended September 30, 2024 ($ millions)	Basis of Netback Calculation						
	Foster Creek	Christina Lake	Sunrise	Lloydminster Oil Sands [1]	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
Gross Sales	4,383	4,782	1,194	2,853	**13,212**	—	**13,212**
Royalties	(893)	(1,146)	(59)	(296)	**(2,394)**	—	**(2,394)**
Revenues	3,490	3,636	1,135	2,557	**10,818**	—	**10,818**
Expenses							
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	656	417	235	141	**1,449**	—	**1,449**
Operating	519	546	191	619	**1,875**	—	**1,875**
Netback	2,315	2,673	709	1,797	**7,494**	—	**7,494**
Realized (Gain) Loss on Risk Management							**23**
Operating Margin							**7,471**

Nine Months Ended September 30, 2024 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced	Other [2]	Total Oil Sands [3]
Gross Sales	**13,212**	6,732	1,066	346	**21,356**
Royalties	**(2,394)**	—	—	(6)	**(2,400)**
Revenues	**10,818**	6,732	1,066	340	**18,956**
Expenses					
Purchased Product	**—**	—	1,066	255	**1,321**
Transportation and Blending	**1,449**	6,732	—	84	**8,265**
Operating	**1,875**	—	—	21	**1,896**
Netback	**7,494**	—	—	(20)	**7,474**
Realized (Gain) Loss on Risk Management	**23**	—	—	—	**23**
Operating Margin	**7,471**	—	—	(20)	**7,451**

(1) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.
(2) Other includes construction, transportation and blending.
(3) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Nine Months Ended September 30, 2023 ($ millions)	Basis of Netback Calculation						
	Foster Creek	Christina Lake	Sunrise	Lloydminster 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)**
Revenues	3,252	3,211	899	2,231	**9,593**	2	**9,595**
Expenses							
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	Adjustments			
	Total Oil Sands	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)**
Revenues	**9,595**	6,578	1,043	281	**17,497**
Expenses					
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**

(1) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.
(2) Other includes construction, transportation and blending.
(3) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Conventional

Three Months Ended September 30, 2024 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	**222**	460	31	**713**
Royalties	**(15)**	—	—	**(15)**
Revenues	**207**	460	31	**698**
Expenses				
Purchased Product	**—**	460	(1)	**459**
Transportation and Blending	**56**	—	24	**80**
Operating	**139**	—	8	**147**
Netback	**12**	—	—	**12**
Realized (Gain) Loss on Risk Management	**—**	—	—	**—**
Operating Margin	**12**	—	—	**12**

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)**
Revenues	**304**	438	41	**783**
Expenses				
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**

(1) Other includes reclassification of costs primarily related to third-party cogeneration, processing and transportation.
(2) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Nine Months Ended September 30, 2024 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	**832**	1,353	98	**2,283**
Royalties	**(61)**	—	—	**(61)**
Revenues	**771**	1,353	98	**2,222**
Expenses				
Purchased Product	**—**	1,353	—	**1,353**
Transportation and Blending	**166**	—	75	**241**
Operating	**408**	—	24	**432**
Netback	**197**	—	(1)	**196**
Realized (Gain) Loss on Risk Management	**(7)**	—	—	**(7)**
Operating Margin	**204**	—	(1)	**203**

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)**
Revenues	**974**	1,258	150	**2,382**
Expenses				
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**

(1) Other includes reclassification of costs primarily related to third-party cogeneration, processing and transportation.
(2) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Offshore

Three Months Ended September 30, 2024 ($ 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	71	300	82	**382**	**453**	(82)	—	**371**
Royalties	(1)	(24)	(9)	**(33)**	**(34)**	9	—	**(25)**
Revenues	70	276	73	**349**	**419**	(73)	—	**346**
Expenses								
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	2	—	—	**—**	**2**	—	—	**2**
Operating	59	30	16	**46**	**105**	(14)	1	**92**
Netback	9	246	57	**303**	**312**	(59)	(1)	**252**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**312**	(59)	(1)	**252**

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)**
Revenues	76	300	59	**359**	**435**	(59)	—	**376**
Expenses								
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**

(1) Revenues and expenses related to the HCML joint venture are accounted for using the equity method in the interim Consolidated Financial Statements.
(2) Primarily related to Offshore project expenses.
(3) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Nine Months Ended September 30, 2024 ($ 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	264	935	229	**1,164**	**1,428**	(229)	—	**1,199**
Royalties	(2)	(72)	(28)	**(100)**	**(102)**	28	—	**(74)**
Revenues	262	863	201	**1,064**	**1,326**	(201)	—	**1,125**
Expenses								
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	9	—	—	**—**	**9**	—	—	**9**
Operating	222	84	44	**128**	**350**	(37)	6	**319**
Netback	31	779	157	**936**	**967**	(164)	(6)	**797**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**967**	(164)	(6)	**797**

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)**
Revenues	221	817	170	**987**	**1,208**	(170)	—	**1,038**
Expenses								
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**

(1) Revenues and expenses related to the HCML joint venture are accounted for using the equity method in the interim Consolidated Financial Statements.
(2) Primarily related to Offshore 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)	**2024**	2023	**2024**	2023
Oil Sands [2]				
Foster Creek	**191.7**	197.6	**190.4**	185.6
Christina Lake	**221.6**	229.4	**227.3**	232.9
Sunrise	**54.4**	51.2	**49.2**	46.1
Lloydminster	**126.6**	119.0	**128.4**	119.5
Total Oil Sands	**594.3**	597.2	**595.3**	584.1
Conventional	**118.1**	127.2	**120.5**	118.5
Offshore				
Atlantic	**7.2**	7.8	**8.6**	7.8
Asia Pacific				
China	**40.5**	43.8	**42.6**	39.4
Indonesia	**16.0**	13.7	**14.8**	14.1
Total Asia Pacific	**56.5**	57.5	**57.4**	53.5
Total Offshore	**63.7**	65.3	**66.0**	61.3
Sales Before Internal Consumption	**776.1**	789.7	**781.8**	763.9
Internal Consumption [3]	**(92.8)**	(87.9)	**(98.4)**	(88.5)
Total Upstream Sales	**683.3**	701.8	**683.4**	675.4

(1) Sales volumes exclude the impact of purchased condensate.
(2) Includes bitumen and heavy crude oil sales.
(3) Represents natural gas volumes produced by the Conventional segment used for internal consumption by the Oil Sands segment.

Other Specified Financial Measures

Per-Unit Operating Expenses and Turnaround Costs

Per-unit operating expenses are specified financial measures used to evaluate the performance of our upstream and downstream operations. We define Canadian Refining per-unit operating expenses as total operating expenses from the Upgrader, the Lloydminster Refinery and the commercial fuels business, divided by total processed inputs. We define U.S. Refining per-unit operating expenses as operating expenses divided by total processed inputs.

Per-unit operating expenses – turnaround costs are specified financial measures used to evaluate the cost of turnarounds for our downstream operations. We define per-unit operating expenses – turnaround costs as the refining segments' operating expenses – turnaround costs divided by total processed inputs.

Our upstream per-unit operating expenses are defined as total operating expenses divided by sales volumes and are part of our Netback calculation, which can be found above.

Per-Unit Transportation Expenses

Per-unit transportation expenses are specified financial measures used to measure transportation expenses on a per-unit basis in our upstream segments. We define per-unit transportation expenses as the total transportation expenses divided by sales volumes. Our Upstream per-unit transportation expenses are part of the transportation and blending line in our Netback calculation, which can be found above.

Per-Unit Depreciation, Depletion and Amortization

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 decommissioning costs, divided by sales volumes.