Cenovus Energy Inc.

Management's Discussion and Analysis (unaudited)

For the Periods Ended September 30, 2025

(Canadian Dollars)

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the periods ended September 30, 2025

TABLE OF CONTENTS

OVERVIEW OF CENOVUS 3
QUARTERLY RESULTS OVERVIEW 4
OPERATING AND FINANCIAL RESULTS 6
COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS 11
OUTLOOK 15
REPORTABLE SEGMENTS 17
- UPSTREAM 17
  - OIL SANDS 17
  - CONVENTIONAL 23
  - OFFSHORE 25
- DOWNSTREAM 30
  - CANADIAN REFINING 30
  - U.S. REFINING 32
- CORPORATE AND ELIMINATIONS 34

LIQUIDITY AND CAPITAL RESOURCES 35
RISK MANAGEMENT AND RISK FACTORS 40
CRITICAL ACCOUNTING JUDGMENTS, ESTIMATION UNCERTAINTIES AND ACCOUNTING POLICIES 40
CONTROL ENVIRONMENT 40
ADVISORY 41
- ABBREVIATIONS AND DEFINITIONS 44
- SPECIFIED FINANCIAL MEASURES 45
- PRIOR PERIOD REVISIONS 58

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, 2025, should be read in conjunction with our September 30, 2025 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2024 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2024 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as at October 30, 2025, 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, 2025. 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 price 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 and sustainability leadership; maximizing value through competitive cost structures and optimizing margins; a focus on financial discipline, including 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 absolute and per share free funds flow growth.

On December 12, 2024, we released our 2025 corporate guidance, which focused on disciplined capital allocation in support of increasing shareholder returns over time. We will continue to be focused on controlling costs, improving the profitability of our strategic downstream business and optimizing our advantaged portfolio to deliver value for our shareholders. Our 2025 corporate guidance was updated on July 30, 2025, and October 30, 2025, 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 in Alberta and British Columbia in the Edson, Clearwater and Rainbow Lake operating areas, in addition to the Northern Corridor, which includes Elmworth and Wapiti. The segment also includes 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 the east coast of Canada and the Asia Pacific region, representing China and 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. The U.S. Refining segment includes the jointly-owned Wood River and Borger refineries held through WRB Refining LP ("WRB"), a jointly-owned entity with operator Phillips 66. On September 30, 2025, Cenovus divested its entire 50 percent interest in WRB. Cenovus markets its own and third-party refined products.

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

In the third quarter, we achieved record production in our upstream operations and record crude oil unit throughput ("throughput") in our downstream operations. Our financial results reflect our strong operating results, as well as an improved commodity price environment compared to the second quarter.

- **Delivered safe and reliable operations.** We maintained safe operations throughout our business and are continually striving to improve our safety record. Safety continues to be our top priority.
- **Sale of interest in WRB.** We divested our entire 50 percent interest in WRB, as announced on September 9, 2025. Proceeds of US$1.3 billion (C$1.8 billion), net of preliminary closing adjustments, were included in accounts receivable and accrued revenues as at September 30, 2025, and were received on October 1, 2025. The divestiture aligns with our strategy of owning and operating assets that are core to our business.
- **Record quarterly upstream production**. We achieved record quarterly upstream production of 832.9 thousand BOE per day. This included record production from our Oil Sands segment of 642.8 thousand BOE per day driven by optimization activities, the ramp-up of sustaining well pads and the ramp-up of production at Narrows Lake. Total upstream production increased from 765.9 thousand BOE per day in the second quarter of 2025, due to the return to full production at Christina Lake following the wildfire related shut-in and resuming full production at Foster Creek after completion of the turnaround in the second quarter.
- **Substantially completed key Oil Sands growth projects.** We have completed the Narrows Lake tie-back to Christina Lake and are now ramping up production. The optimization project at Foster Creek was approximately 98 percent complete as at September 30, 2025, with four new steam generators brought online in the quarter, supporting higher production ahead of schedule. Commissioning of the water treating and de-oiling units is underway and new well pads will be brought online in early 2026. At Sunrise, we are preparing a well pad for steaming in the fourth quarter to support continued production growth. At our Lloydminster conventional heavy oil assets, we continue to progress our heavy oil drilling program.
- **Achieved Offshore milestones at the West White Rose Project.** In the quarter, the topsides were placed atop the concrete gravity structure, and we completed the subsea tie-ins to our existing production system at the *SeaRose* floating production, storage and offloading unit ("FPSO"). The remainder of the platform hookup and commissioning work is expected to be completed in the fourth quarter. We are on track to begin drilling by the end of 2025.
- **Record crude throughput in our downstream assets.** Average throughput in our downstream assets was 710.7 thousand barrels per day, compared with 665.8 thousand barrels per day in the second quarter of 2025. This represented a total downstream crude unit utilization of 99 percent. Our Canadian assets continue to run near capacity, while the completion of turnarounds and operational improvement initiatives in our operated U.S. assets drove higher process unit utilization and lower per-unit operating costs.
- **Reported solid financial results.** Adjusted Funds Flow was $2.5 billion, up from $1.5 billion in the second quarter of 2025, mainly due to higher sales volumes and lower operating expenses, driven by strong operating performance across our assets. The increases were also due in part to higher realized pricing in our oil sands assets and stronger refining margins in our U.S. Refining operations. Cash from operating activities was $2.1 billion, a decrease from $2.4 billion in the second quarter of 2025, mainly due to changes in non-cash working capital.
- **Increased our returns to shareholders.** We returned $1.3 billion to common shareholders, including the purchase of 40.4 million common shares for $918 million through our normal course issuer bid ("NCIB") and $356 million through common share dividends. On October 30, 2025, our Board of Directors declared a fourth quarter dividend of $0.200 per common share.

- **Acquisition of MEG Energy Corp.** On August 21, 2025, we entered into a definitive agreement to acquire all of the issued and outstanding common shares of MEG Energy Corp. ("MEG") through a plan of arrangement (the "MEG Acquisition"). From October 8, 2025, to October 15, 2025, the Company acquired an aggregate of 25.0 million MEG common shares for $752 million. On October 26, 2025, Cenovus entered into a second amending agreement. The MEG Acquisition is subject to shareholder, court and other customary approvals.

Summary of Quarterly Results

	Nine Months Ended September 30,		2025			2024				2023
($ millions, except where indicated)	**2025**	2024	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Upstream Production Volumes [1] (MBOE/d)	**805.9**	790.9	**832.9**	765.9	818.9	816.0	771.3	800.8	800.9	808.6
Downstream Total Processed Inputs [2][3] (Mbbls/d)	**724.5**	670.4	**757.6**	714.9	700.5	700.5	674.4	652.9	683.8	605.7
Crude Oil Unit Throughput [2] (Mbbls/d)	**680.9**	640.3	**710.7**	665.8	665.4	666.7	642.9	622.7	655.2	579.1
Downstream Production Volumes [1][2] (Mbbls/d)	**741.1**	683.3	**770.3**	729.4	722.4	722.6	685.2	659.5	702.1	627.4
Revenues [4]	**38,813**	41,464	**13,195**	12,319	13,299	12,813	13,819	14,582	13,063	13,134
Operating Margin [5]	**7,831**	8,535	**2,954**	2,066	2,811	2,274	2,408	2,936	3,191	2,151
Operating Margin – Upstream [6]	**7,775**	8,451	**2,590**	2,137	3,048	2,670	2,731	3,089	2,631	2,455
Operating Margin – Downstream [6]	**56**	84	**364**	(71)	(237)	(396)	(323)	(153)	560	(304)
Cash From (Used In) Operating Activities	**5,820**	7,206	**2,131**	2,374	1,315	2,029	2,474	2,807	1,925	2,946
Adjusted Funds Flow [5]	**6,197**	6,563	**2,466**	1,519	2,212	1,601	1,960	2,361	2,242	2,062
Per Share – Basic [5] ($)	**3.43**	3.53	**1.38**	0.84	1.21	0.88	1.06	1.27	1.20	1.10
Per Share – Diluted [5] ($)	**3.42**	3.50	**1.38**	0.84	1.21	0.87	1.05	1.26	1.19	1.08
Capital Investment	**3,547**	3,537	**1,154**	1,164	1,229	1,478	1,346	1,155	1,036	1,170
Free Funds Flow [5]	**2,650**	3,026	**1,312**	355	983	123	614	1,206	1,206	892
Excess Free Funds Flow [5]	**812**	1,713	**745**	(306)	373	(416)	146	735	832	471
Net Earnings (Loss)	**2,996**	2,996	**1,286**	851	859	146	820	1,000	1,176	743
Per Share – Basic ($)	**1.65**	1.60	**0.72**	0.47	0.47	0.08	0.44	0.53	0.62	0.39
Per Share – Diluted ($)	**1.65**	1.59	**0.72**	0.45	0.47	0.07	0.42	0.53	0.62	0.32
Total Assets	**53,573**	54,680	**53,573**	55,820	56,380	56,539	54,680	56,000	54,994	53,915
Long-Term Debt, Including Current Portion	**7,156**	7,199	**7,156**	7,241	7,524	7,534	7,199	7,275	7,227	7,108
Net Debt	**5,255**	4,196	**5,255**	4,934	5,079	4,614	4,196	4,258	4,827	5,060
Cash Returns to Common and Preferred Shareholders	**2,688**	2,540	**1,274**	819	595	706	1,070	1,034	436	731
Common Shares – Base Dividends	**1,047**	925	**356**	364	327	330	329	334	262	261
Base Dividends Per Common Share ($)	**0.580**	0.500	**0.200**	0.200	0.180	0.180	0.180	0.180	0.140	0.140
Common Shares – Variable Dividends	**—**	251	**—**	—	—	—	—	251	—	—
Variable Dividends Per Common Share ($)	**—**	0.135	**—**	—	—	—	—	0.135	—	—
Purchase of Common Shares Under NCIB	**1,281**	1,337	**918**	301	62	108	732	440	165	350
Payment for Purchase of Warrants	**—**	—	**—**	—	—	—	—	—	—	111
Dividends Paid on Preferred Shares	**10**	27	**—**	4	6	18	9	9	9	9
Preferred Share Redemptions	**350**	—	**—**	150	200	250	—	—	—	—

(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) 2024 comparative periods reflect certain revisions. See the Prior Period Revisions section of this MD&A for further details.
(5) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(6) Specified 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,		
	2025	**Percent Change**	2024	**2025**	**Percent Change**	2024
Production Volumes by Segment [1] (MBOE/d)						
Oil Sands	**642.8**	**9**	587.7	**616.4**	**2**	604.8
Conventional [2]	**126.9**	**7**	118.1	**123.6**	**3**	120.5
Offshore [3]	**63.2**	**(4)**	65.5	**65.9**	**—**	65.6
Total Production Volumes	**832.9**	**8**	771.3	**805.9**	**2**	790.9
Production Volumes by Product [1]						
Bitumen (Mbbls/d)	**615.2**	**8**	569.6	**589.9**	**1**	585.4
Heavy Crude Oil (Mbbls/d)	**25.4**	**56**	16.3	**24.1**	**39**	17.4
Light Crude Oil (Mbbls/d)	**16.3**	**20**	13.6	**16.7**	**27**	13.2
NGLs (Mbbls/d)	**27.8**	**(10)**	31.0	**29.1**	**(10)**	32.2
Conventional Natural Gas (MMcf/d)	**889.5**	**5**	844.6	**876.3**	**2**	855.8
Total Production Volumes (MBOE/d)	**832.9**	**8**	771.3	**805.9**	**2**	790.9
Per-Unit Operating Expenses by Segment ($/BOE)						
Oil Sands [4]	**11.21**	**—**	11.17	**12.14**	**6**	11.50
Conventional [2] [5]	**10.33**	**(19)**	12.77	**10.40**	**(16)**	12.35
Offshore [3] [5]	**19.19**	**7**	17.97	**16.86**	**(13)**	19.36

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

(2) For the three and nine months ended September 30, 2025, reported Conventional segment production and per-unit operating expenses include Cenovus's 30 percent equity interest in the Duvernay Energy Corporation ("Duvernay") joint venture, which is accounted for using the equity method in the interim Consolidated Financial Statements. Operating expenses for the Conventional segment, excluding our equity interests in the Duvernay joint venture, were $127 million and $369 million, respectively.

(3) Reported Offshore segment production and per-unit operating expenses include Cenovus's 40 percent equity interest in the HCML joint venture, which is accounted for using the equity method in the interim Consolidated Financial Statements. Operating expenses for the Offshore segment, excluding our equity interests in the HCML joint venture, for the three and nine months ended September 30, 2025, were $103 million and $273 million, respectively (2024 – $92 million and $319 million, respectively).

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

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

Production

Total upstream production increased in the three and nine months ended September 30, 2025, compared with 2024, due to:

- Optimization activities and the ramp-up of well pads at our Foster Creek, Lloydminster thermal, Sunrise and Christina Lake assets.
- Strong performance from base and new development wells at our Conventional assets.
- Strong base production and additional volumes from new development wells at our Lloydminster conventional heavy oil assets.
- The ramp-up of production at Narrows Lake.

The increases were partially offset by the temporary shut-in of production at our Rush Lake facilities as we respond to and recover from a casing failure at a steam injection well that occurred in the second quarter of 2025. Plans to safely commence and ramp-up production are expected by the end of the year.

In the third quarter of 2024, production volumes were lower due to turnaround activities at Christina Lake and in our Conventional segment.

The year-over-year increase was primarily due to the factors discussed above, partially offset by:

- Turnaround activities at Foster Creek in the second quarter of 2025 and at Sunrise in the second and third quarters of 2025.
- The temporary shut-in of production at Christina Lake in response to wildfire activity.

Per-Unit Operating Expenses

For the nine months ended September 30, 2025, per-unit operating expenses increased in the Oil Sands segment compared with 2024, primarily due to higher costs in our Lloydminster thermal assets related to the incident at Rush Lake and higher turnaround costs at Foster Creek and Sunrise. Per-unit operating expenses decreased in the Conventional segment primarily due to lower turnaround costs, and processing and gathering costs compared with 2024. Per-unit operating expenses decreased in the Offshore segment compared with 2024, primarily due to higher sales volumes and lower operating expenses as the White Rose field resumed production following the completion of the *SeaRose* asset life extension ("ALE") project in the first quarter of 2025.

We continue to focus on controlling costs through securing long-term contracts, working with vendors and purchasing long-lead items to mitigate future cost escalations.

Selected Operating and Financial Results — Downstream

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2025	**Percent Change**	2024	**2025**	**Percent Change**	2024
Crude Oil Unit Throughput by Segment (Mbbls/d)						
Canadian Refining	**105.4**	**6**	99.4	**109.9**	**28**	85.8
U.S. Refining	**605.3**	**11**	543.5	**571.0**	**3**	554.5
Total Crude Oil Unit Throughput	**710.7**	**11**	642.9	**680.9**	**6**	640.3
Production Volumes by Product [(1)] (Mbbls/d)						
Gasoline	**304.7**	**17**	259.7	**288.9**	**6**	273.4
Distillates [(2)]	**247.6**	**14**	217.1	**231.4**	**7**	216.7
Synthetic Crude Oil	**48.3**	**2**	47.3	**52.0**	**35**	38.4
Asphalt	**47.7**	**3**	46.1	**43.7**	**1**	43.4
Ethanol	**5.3**	**(4)**	5.5	**4.9**	**(4)**	5.1
Other	**116.7**	**7**	109.5	**120.2**	**13**	106.3
Total Production Volumes	**770.3**	**12**	685.2	**741.1**	**8**	683.3
Per-Unit Operating Expenses by Segment [(3)] ($/bbl)						
Canadian Refining	**11.38**	**(22)**	14.63	**10.96**	**(59)**	26.65
U.S. Refining	**10.32**	**(28)**	14.37	**12.89**	**—**	12.89
Per-Unit Operating Expenses – Excluding Turnaround Costs by Segment [(3)] ($/bbl)						
Canadian Refining	**11.38**	**(7)**	12.22	**10.93**	**(34)**	16.67
U.S. Refining	**9.67**	**(24)**	12.74	**10.73**	**(9)**	11.77

(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. See the Specified Financial Measures Advisory of this MD&A. In the Canadian Refining segment, operating expenses represent expenses associated with the Lloydminster Upgrader, the Lloydminster Refinery and the commercial fuels business.

Total downstream throughput and refined product production increased in the three and nine months ended September 30, 2025, compared with the same periods in 2024. The increases were primarily due to our Canadian Refining assets running near, or above, full capacity and ongoing operational improvement initiatives at our operated U.S. Refining assets.

In the nine months ended September 30, 2025, per-unit operating expenses excluding turnaround costs decreased in the Canadian Refining segment compared with 2024, due to lower project costs and higher total processed inputs. Total processed inputs were lower and operating expenses were higher in 2024, due to the major turnaround completed at the Upgrader in the second quarter of 2024.

In the nine months ended September 30, 2025, per-unit operating expenses excluding turnaround costs decreased in the U.S. Refining segment compared with 2024, primarily due to lower repairs and maintenance, and project costs, partially offset by higher electricity costs.

Selected Consolidated Financial Results

Revenues

Revenues decreased five percent to $13.2 billion and decreased six percent to $38.8 billion in the three and nine months ended September 30, 2025, respectively, compared with the same periods in 2024. The decrease for both periods was primarily due to lower benchmark crude oil and refined product pricing, offset by higher sales volumes.

Operating Margin

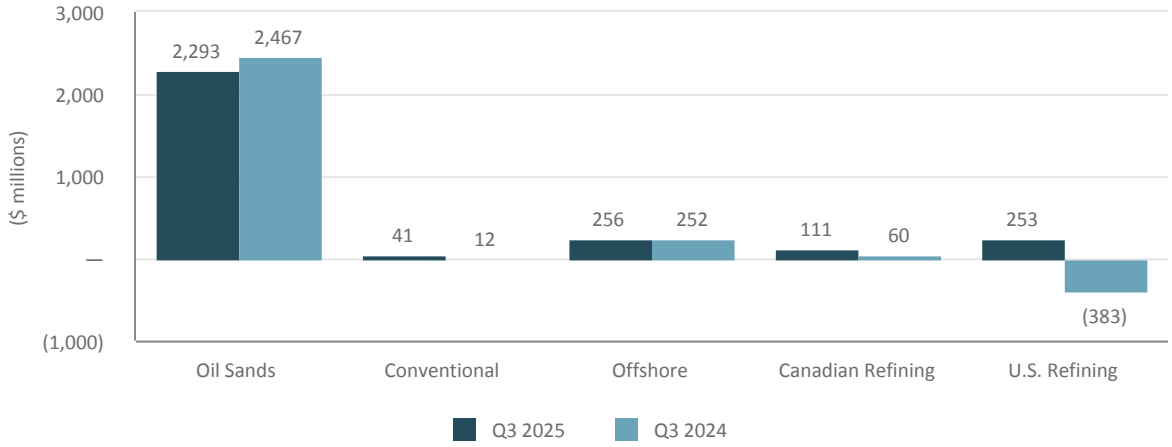
Operating Margin is a non-GAAP financial measure and is used to provide a consistent measure of the cash-generating performance of our assets for comparability of our underlying financial performance between periods.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2025**	2024	**2025**	2024
Gross Sales				
External Sales [(1)]	**14,053**	14,748	**41,198**	43,999
Intersegment Sales	**1,944**	2,309	**6,893**	6,620
	15,997	17,057	**48,091**	50,619
Royalties	**(858)**	(929)	**(2,385)**	(2,535)
Revenues [(1)]	**15,139**	16,128	**45,706**	48,084
Expenses				
Purchased Product [(1)]	**7,995**	9,295	**24,233**	25,562
Transportation and Blending	**2,543**	2,661	**8,411**	8,515
Operating Expenses	**1,636**	1,778	**5,226**	5,451
Realized (Gain) Loss on Risk Management	**11**	(14)	**5**	21
Operating Margin	**2,954**	2,408	**7,831**	8,535

(1) Comparative periods reflect certain revisions. See the Prior Period Revisions section of this MD&A for further details.

Operating Margin by Segment

Three Months Ended September 30, 2025 and 2024

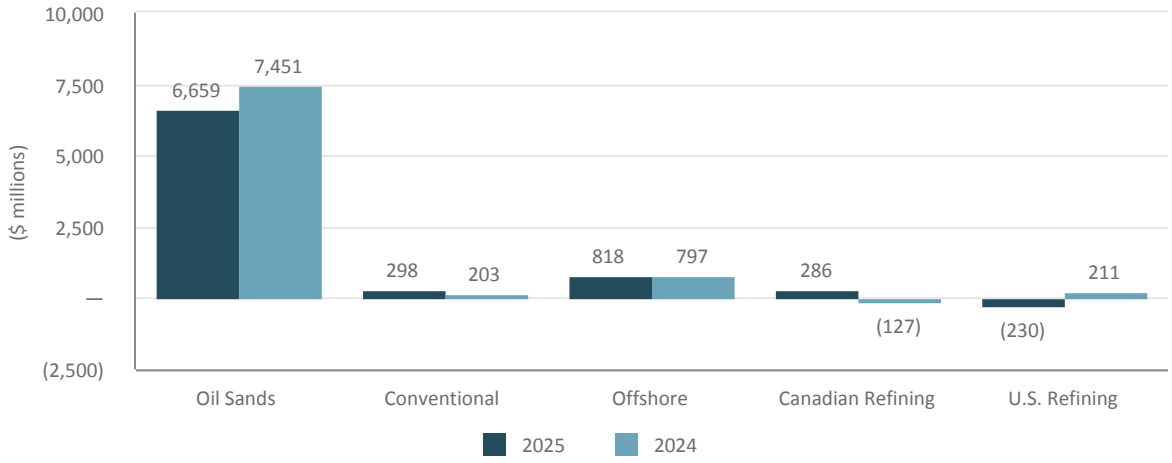


Operating Margin increased compared with the third quarter of 2024, primarily due to:

- Higher market crack spreads and higher sales volumes in our U.S. Refining segment.
- Lower operating expenses in our U.S. and Canadian refining segments.

The increases above were partially offset by a lower operating margin in our Oil Sands segment due to lower Realized Sales Prices, partially offset by higher sales volumes and a narrower condensate-WCS differential. Realized Sales Prices decreased quarter-over-quarter due to lower WTI benchmark prices, partially offset by a narrower WTI-WCS differential.

Nine Months Ended September 30, 2025 and 2024



Operating Margin decreased in the nine months ended September 30, 2025, compared with 2024, primarily due to:

- Lower Realized Sales Prices impacting revenues in our Oil Sands segment, due to lower benchmark prices, as discussed above.
- The narrowing of the WTI-WCS differential impacting our U.S. Refining and Canadian Refining segments.

The decrease was partially offset by:

- Higher sales volumes in our Oil Sands and Canadian Refining segments.
- Lower operating expenses in our Canadian Refining segment due to lower turnaround costs, as there were no significant turnarounds in 2025.
- An increase in market crack spreads impacting our U.S. Refining 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)	**2025**	2024	**2025**	2024
Cash From (Used in) Operating Activities	**2,131**	2,474	**5,820**	7,206
(Add) Deduct:				
Settlement of Decommissioning Liabilities	**(94)**	(74)	**(198)**	(170)
Net Change in Non-Cash Working Capital	**(241)**	588	**(179)**	813
Adjusted Funds Flow	**2,466**	1,960	**6,197**	6,563

In the three and nine months ended September 30, 2025, cash from operating activities decreased compared with the same periods in 2024. Quarter-over-quarter, the decrease was primarily due to changes in non-cash working capital, partially offset by higher Operating Margin. Year-over-year, the decrease was due to changes in non-cash working capital and lower Operating Margin.

For the three months ended September 30, 2025, changes in non-cash working capital decreased cash from operating activities by $241 million, primarily due to changes in accounts payable and accounts receivable, excluding the impact of the divestiture of WRB.

For the nine months ended September 30, 2025, changes in non-cash working capital decreased cash from operating activities by $179 million, primarily due to changes in accounts receivable and income tax payable, partially offset by changes in inventories, excluding the impact of the divestiture of WRB.

Adjusted Funds Flow increased in the three months ended September 30, 2025, compared with 2024, primarily due to higher Operating Margin, as discussed above. Adjusted Funds Flow in the nine months ended September 30, 2025, decreased compared with 2024, due to lower Operating Margin, as discussed above, partially offset by lower long-term incentive costs.

Net Earnings (Loss)

Net earnings in the three months ended September 30, 2025, were $1.3 billion, compared with $820 million in 2024, due to higher Operating Margin, as discussed above, and lower income tax expense, partially offset by foreign exchange losses in 2025, compared with gains in 2024.

In the nine months ended September 30, 2025, and 2024, net earnings were consistent at $3.0 billion as the lower Operating Margin discussed above, was offset by lower income tax expense and foreign exchange gains in 2025, compared with losses in 2024.

Net Debt

As at ($ millions)	**September 30, 2025**	December 31, 2024
Short-Term Borrowings	**—**	173
Current Portion of Long-Term Debt	**—**	192
Long-Term Portion of Long-Term Debt	**7,156**	7,342
Total Debt	**7,156**	7,707
Cash and Cash Equivalents	**(1,901)**	(3,093)
Net Debt	**5,255**	4,614

Total debt decreased by $551 million from December 31, 2024, primarily due to the repayment of unsecured notes during the third quarter, unrealized foreign exchange gains on long-term debt and lower short-term borrowings due to the divestiture of our 50 percent interest in WRB.

Net Debt increased by $641 million from December 31, 2024, mainly due to capital investment of $3.5 billion, common share purchases of $1.3 billion, base dividends of $1.0 billion and preferred share redemptions of $350 million, partially offset by cash from operating activities of $5.8 billion. Proceeds from the WRB divestiture were included in accounts receivable and accrued revenues as at September 30, 2025, and were received on October 1, 2025. 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)	**2025**	2024	**2025**	2024
Upstream				
Oil Sands	**675**	681	**2,082**	1,941
Conventional	**107**	106	**302**	300
Offshore	**217**	355	**728**	809
Total Upstream	**999**	1,142	**3,112**	3,050
Downstream				
Canadian Refining	**33**	44	**83**	145
U.S. Refining	**120**	153	**343**	320
Total Downstream	**153**	197	**426**	465
Corporate and Eliminations	**2**	7	**9**	22
Total Capital Investment	**1,154**	1,346	**3,547**	3,537

(1) Includes expenditures on property, plant and equipment ("PP&E"), exploration and evaluation ("E&E") assets, and capitalized interest. Excludes capital expenditures related to equity interests in joint ventures accounted for using the equity method in the interim Consolidated Financial Statements.

For the nine months ended September 30, 2025, capital investment was mainly related to:

- Sustaining, optimization and redevelopment programs 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.
- Growth projects in our Oil Sands segment, including the progression of the drilling program at our Lloydminster conventional heavy oil assets, the Sunrise growth program, the optimization project at Foster Creek and the Narrows Lake tie-back to Christina Lake.
- Reliability and sustaining activities in our refining segments.
- Drilling, completion, tie-in and infrastructure projects in the Conventional segment.

Drilling Activity

Nine Months Ended September 30,	Net Stratigraphic Test Wells and Observation Wells		Net Production Wells [1]	
	2025	2024	**2025**	2024
Foster Creek	**73**	82	**32**	17
Christina Lake	**65**	58	**21**	16
Sunrise	**21**	40	**10**	8
Lloydminster Thermal	**14**	25	**12**	18
Lloydminster Conventional Heavy Oil	**1**	8	**65**	23
	174	213	**140**	82

(1) Steam-assisted gravity drainage 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 evaluate our assets. Observation wells were drilled to gather information and monitor reservoir conditions.

(net wells)	Nine Months Ended September 30, 2025 [1]			Nine Months Ended September 30, 2024		
	Drilled	**Completed**	**Tied-in**	Drilled	Completed	Tied-in
Conventional	**35**	**33**	**28**	24	24	17

(1) Includes values attributable to Cenovus's 30 percent equity interest in the Duvernay joint venture.

In the Offshore segment, no wells were drilled or completed in the first nine months of 2025 (2024 – drilled and evaluated one exploration well in China).

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$/bbl, unless otherwise indicated)	Nine Months Ended September 30,					
	2025	**Percent Change**	2024	**Q3 2025**	Q2 2025	Q3 2024
Dated Brent	**70.85**	**(14)**	82.79	**69.07**	67.82	80.18
WTI	**66.70**	**(14)**	77.54	**64.93**	63.74	75.09
Differential Dated Brent – WTI	**4.15**	**(21)**	5.25	**4.14**	4.08	5.09
WCS at Hardisty	**55.59**	**(10)**	62.05	**54.54**	53.47	61.54
Differential WTI – WCS at Hardisty	**11.11**	**(28)**	15.49	**10.39**	10.27	13.55
WCS at Hardisty (C$/bbl)	**77.79**	**(8)**	84.45	**75.11**	73.96	83.95
WCS at Nederland	**63.78**	**(10)**	71.03	**62.58**	61.00	68.51
Differential WTI – WCS at Nederland	**2.92**	**(55)**	6.51	**2.35**	2.74	6.58
Condensate (C5 at Edmonton)	**65.48**	**(11)**	73.71	**63.10**	63.46	71.19
Differential Condensate – WTI Premium/(Discount)	**(1.22)**	**(68)**	(3.83)	**(1.83)**	(0.28)	(3.90)
Differential Condensate – WCS at Hardisty Premium/(Discount)	**9.89**	**(15)**	11.66	**8.56**	9.99	9.65
Condensate (C$/bbl)	**91.66**	**(9)**	100.28	**86.91**	87.77	97.10
Synthetic at Edmonton	**66.68**	**(13)**	76.38	**66.26**	64.72	76.41
Differential Synthetic – WTI Premium/(Discount)	**(0.02)**	**(98)**	(1.16)	**1.33**	0.98	1.32
Synthetic at Edmonton (C$/bbl)	**93.30**	**(10)**	103.96	**91.27**	89.52	104.22
Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**84.19**	**(10)**	93.62	**84.87**	84.61	92.29
Chicago Ultra-low Sulphur Diesel ("ULSD")	**91.27**	**(9)**	100.21	**97.78**	86.91	96.55

(1) These benchmark prices are not our Realized Sales Prices and represent approximate values. For our Realized Sales Prices refer to the Netback tables in the upstream reportable segments section of this MD&A.

Selected Benchmark Prices and Exchange Rates — Continued [1]

(Average US$/bbl, unless otherwise indicated)	Nine Months Ended September 30, 2025	Percent Change	2024	Q3 2025	Q2 2025	Q3 2024
Refining Benchmarks						
Chicago 3-2-1 Crack Spread [2]	**19.85**	**9**	18.27	**24.24**	21.64	18.62
Group 3 3-2-1 Crack Spread [2]	**21.09**	**16**	18.19	**23.72**	23.07	18.95
Renewable Identification Numbers ("RINs")	**5.74**	**57**	3.65	**6.33**	6.12	3.89
Upgrading Differential [3] (C$/bbl)	**15.38**	**(21)**	19.40	**15.99**	15.46	20.26
Natural Gas Prices						
AECO [4] (C$/Mcf)	**1.50**	**3**	1.45	**0.63**	1.69	0.69
NYMEX [5] (US$/Mcf)	**3.39**	**61**	2.10	**3.07**	3.44	2.16
Foreign Exchange Rates						
US$ per C$1 – Average	**0.715**	**(3)**	0.735	**0.726**	0.723	0.733
US$ per C$1 – End of Period	**0.718**	**(3)**	0.741	**0.718**	0.733	0.741
RMB per C$1 – Average	**5.164**	**(2)**	5.293	**5.197**	5.226	5.255

(1) These benchmark prices are not our Realized Sales Prices and represent approximate values. For our Realized Sales Prices refer to the Netback tables in the upstream reportable segments section of this MD&A.
(2) The average 3-2-1 crack spread is an indicator of the adjusted refining margin and is valued on a last-in, first-out accounting basis.
(3) 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 Canadian Refining assets; however, it is used as a general market indicator.
(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 2025, global crude oil benchmark prices, Brent and WTI, decreased compared with the third quarter of 2024, due to uncertainty surrounding the U.S. economy, tariff policies and increasing global supply with the continued unwinding of OPEC+ production cuts. In the third quarter of 2025, Brent and WTI increased compared with the second quarter of 2025, as strong seasonal demand for crude supported prices.

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.

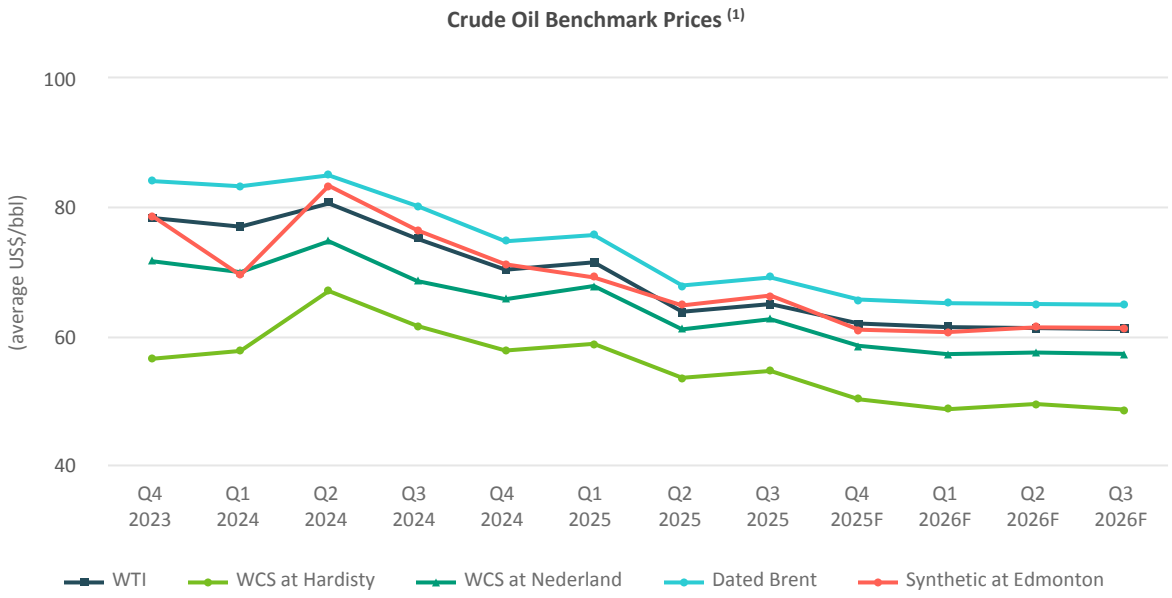
WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WCS at Hardisty differential to WTI is a function of the quality differential of light and heavy crude, and the cost of transport. In the nine months ended September 30, 2025, the WTI-WCS differential at Hardisty narrowed compared with 2024, due to:

- The start-up of Trans Mountain Pipeline expansion project ("TMX") increasing market access for WCS crude.
- Low inventory levels in the Western Canadian Sedimentary Basin as well as strong global demand for heavy crudes.
- Declining output from Mexico and Venezuela.
- Strong pricing for fuel oil in which heavy grades yield more versus light grades.

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 nine months ended September 30, 2025, the WTI-WCS at Nederland differential narrowed compared with 2024, due to strong global demand for heavy crudes, as well as other factors mentioned above.

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

In the nine months ended September 30, 2025, synthetic crude oil at Edmonton strengthened relative to WTI compared with 2024. The strength in pricing relative to 2024 was a function of deep discounts in the first quarter of 2024 due to high synthetic crude oil production in Alberta and the supply of light crude oil being above pipeline capacity on light crude oil pipelines with limited local storage capacity.



(1) Forward pricing as at September 30, 2025.

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 20 percent to 35 percent. The Condensate-WCS differential is an important benchmark, as a higher premium generally results in a decrease in Operating Margin 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 nine months ended September 30, 2025, the average Edmonton condensate benchmark traded at a smaller discount to WTI compared with 2024, due to the same factors impacting the synthetic crude oil to WTI differential, as discussed above, as well as tight Canadian supply and low Canadian inventories.

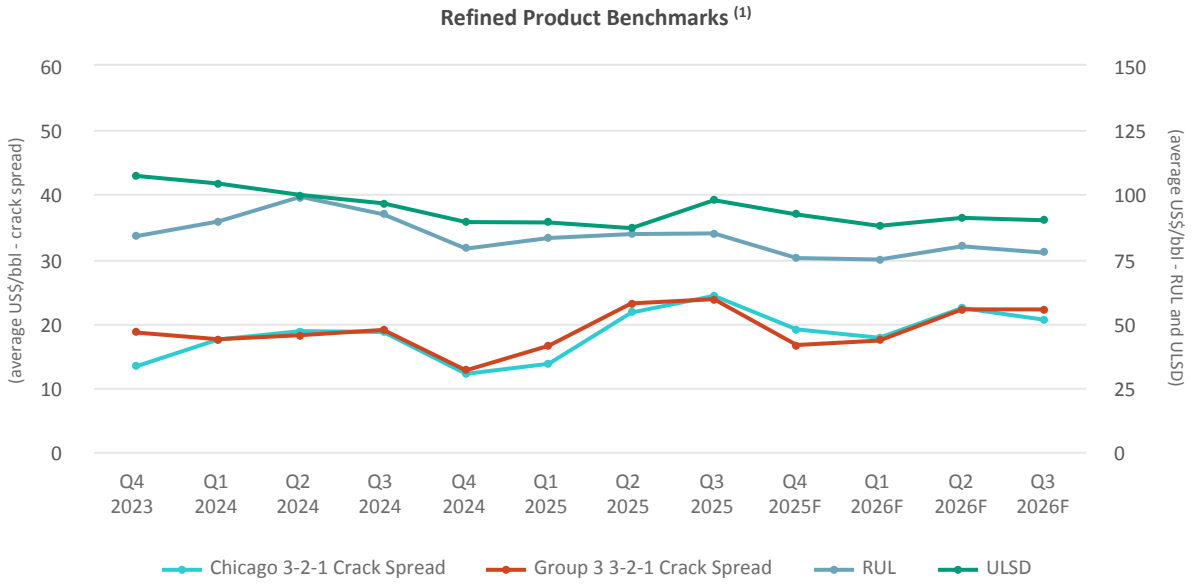
Refining Benchmarks

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 adjusted 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.

In the nine months ended September 30, 2025, refined product crack spreads in Chicago and Group 3 increased compared with the same period in 2024. The increase can be largely attributed to strong third quarter product cracks as global and North American refinery outages supported refined product pricing and new refining capacity has been slow to ramp up. Crack spreads increased in the third quarter of 2025, compared with the second quarter of 2025, consistent with seasonal trends as driving season increases demand and due to refinery outages mentioned above. The average cost of RINs was higher in the nine months ended September 30, 2025, compared with the same period of 2024, due to weaker U.S. production and imports of renewable diesel and biodiesel causing a decline in RINs generation.

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 adjusted refining margin is affected by various other factors such as the quality and purchase location of crude oil feedstock, and refinery configuration and product output. The benchmark 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.



(1) Forward pricing as at September 30, 2025.

Natural Gas Benchmarks

In the nine months ended September 30, 2025, AECO prices increased compared with 2024, though not as much as the increase in NYMEX pricing, as the AECO discount widened due to strong production levels and limited Western Canadian takeaway capacity. In the nine months ended September 30, 2025, NYMEX natural gas prices increased compared with 2024. This is largely a rebound from weak 2024 pricing due to oversupply and high inventories, whereas prices in 2025 have been supported by strong liquified natural gas ("LNG") demand. 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. Changes in foreign exchange rates also impact the translation of our U.S. and Asia Pacific operations.

In the three and nine months ended September 30, 2025, on average, the Canadian dollar weakened relative to the U.S. dollar compared with the same periods of 2024, positively impacting our reported revenues and negatively impacting our U.S. Refining operating expenses. A portion of our long-term sales contracts in the Asia Pacific region are priced in RMB. An increase in the value of the Canadian dollar relative to the RMB will decrease the revenues received in Canadian dollars from the sale of natural gas commodities in the region. In the three and nine months ended September 30, 2025, on average, the Canadian dollar weakened relative to RMB, compared with the same periods of 2024, positively impacting our reported revenues.

Interest Rate Benchmarks

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

As at September 30, 2025, the Bank of Canada's policy interest rate was 2.50 percent. On October 29, 2025, the Bank of Canada reduced the policy interest rate by 25 basis points to 2.25 percent.

OUTLOOK

Commodity Price Outlook

Global crude oil prices have fallen in 2025 relative to 2024 and have been relatively range bound over the last two quarters. OPEC+ policy continues to remain crucial to global oil supply and demand balances, and prices. The unwinding of OPEC+ voluntary production cuts that started in May 2025 has weighed on oil prices. Crude oil price trajectory remains uncertain and volatile amid a market with unpredictable key drivers as global crude markets remain reactionary to geopolitical headlines.

The policies around tariffs, trade relations and global geopolitical conflicts will be key considerations for energy prices. Global 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 geopolitical tensions between Israel and Iran, the Russian invasion of Ukraine, the extent to which Russian exports are reduced by sanctions or production cuts, the pace of non-OPEC+ supply growth, and tensions between Venezuela and Guyana.

The global trade war has the potential to reduce global GDP growth and global oil demand, while increasing recessionary risks, but the actual effects have been less pronounced than expected and repeated pauses to tariffs have limited the direct economic impacts. We expect heightened price volatility across all commodities to continue until there is a firm resolution on the duration and magnitude of the tariffs. Impacts of the One Big Beautiful Bill Act in the U.S. are generally positive for the oil and gas industry in the long-term, but it is unlikely that there will be significant near-term implications. While energy products from Canada have been protected from ad valorem tariffs and are expected to remain so, the renegotiation of the Canada-United States-Mexico Agreement ("CUSMA") may impact the supply of energy products into the United States from Canada and Mexico.

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

- OPEC+ policy and the pace at which OPEC+ unwinds production cuts.
- In the near-term, there is a higher risk of a tariff-induced global economic slowdown that could slow oil demand.
- 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 does not exceed Canadian crude oil export capacity. As expected, the start-up of TMX in 2024 is having a narrowing impact on the WTI-WCS differential.
- 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.
- AECO and NYMEX natural gas prices are expected to remain range bound. The prospect of new LNG facilities in the U.S. and Canada coming into service or ramping up in the next year could increase demand and support North American natural gas prices. Weather will also 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, the U.S. Administration's policies toward Canada-U.S. trade, crude oil prices and emerging macro-economic factors.

Most of our upstream crude oil and downstream refined product production is 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 is used as crude oil feedstock at our downstream refining operations. Condensate extracted from our blended crude oil is sold back to our Oil Sands segment.

Our refining capacity is primarily focused in the U.S. Midwest, along with smaller exposures in the USGC and Alberta, exposing us 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 2025

Our 2025 priorities are focused on top-tier safety performance, maintaining and growing our competitive advantages in our Oil Sands business, executing on our growth projects and implementing operational improvements in our downstream business. We will continue to maintain our returns to shareholders, and 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.

Oil Sands Business

Our Oil Sands business is the backbone of our company. Maintaining and growing our competitive advantage through our asset development and operating strategy, while operating safely and reliably, is critical to our Company.

Project Execution

Investing in future growth is a focus for us, with several key projects underway, including the West White Rose project, the optimization and sulphur recovery projects at Foster Creek, the Sunrise growth program and the Lloydminster conventional heavy oil drilling program.

We have completed the Narrows Lake tie-back to Christina Lake. We achieved first oil at Narrows Lake and we continue to ramp-up production as planned.

Downstream Competitiveness

A competitive, reliable downstream business is essential to our integrated business. It allows us to be agile in our response to fluctuating demand for refined products and serves as a natural partial hedge in times of widening location and heavy oil differentials.

We will continue to implement operational improvements to our downstream assets to maximize the long-term profitability of our assets.

Returns to Shareholders

Maintaining a strong balance sheet with the resilience to withstand price volatility and capitalize on opportunities throughout the commodity price cycle is a key element of Cenovus's capital allocation framework. We plan to steward Net Debt to $4.0 billion and return 100 percent of Excess Free Funds Flow to shareholders over time. For further details, see the Liquidity and Capital Resources section of this MD&A.

Cost Leadership

We aim to maximize shareholder value through a continued focus on low-cost structures and margin optimization across our business. 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.

Sustainability

Sustainability is central to Cenovus's culture. We have established targets in our sustainability 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 acceptance and belonging is available in Cenovus's 2024 Corporate Social Responsibility report on our website at cenovus.com.

2025 Corporate Guidance

Our 2025 corporate guidance, as updated on October 30, 2025, is available on our website at cenovus.com. Updates reflect the divestiture of our 50 percent interest in WRB, which includes reductions to U.S. Refining throughput and downstream turnaround expenses.

The following table is a sub-set of our full updated guidance for 2025:

	Capital Investment ($ millions)	Production (MBOE/d)	Crude Oil Unit Throughput (Mbbls/d)
Upstream			
Oil Sands	**2,700 - 2,800**	**620 - 625**	
Conventional	**350 - 400**	**120 - 125**	
Offshore	**900 - 1,000**	**65 - 75**	
Upstream Total	**3,950 - 4,200**	**805 - 825**	
Downstream			
Canadian Refining			**105 - 110**
U.S. Refining			**510 - 515**
Downstream Total	**650 - 750**		**615 - 625**
Corporate and Eliminations	**Up to 50**		

We continue to execute our capital program and there have been no changes to our full year capital investment range of $4.6 billion and $5.0 billion. This includes $3.2 billion directed towards sustaining capital to maintain base production and support continued safe and reliable operations, and between $1.4 billion and $1.8 billion in optimization growth capital.

REPORTABLE SEGMENTS

UPSTREAM

Oil Sands

In the third quarter of 2025, we:

- Delivered safe and reliable operations, including the safe execution of a turnaround at Sunrise.
- Achieved record production of 642.8 thousand BOE per day (2024 – 587.7 thousand BOE per day).
- Generated Operating Margin of $2.3 billion, a decrease of $174 million compared with 2024, primarily due to lower Realized Sales Prices, partially offset by higher sales volumes.
- Averaged a Netback of $39.56 per barrel (2024 – $45.16 per barrel).
- Invested capital of $675 million for sustaining activities and growth projects.

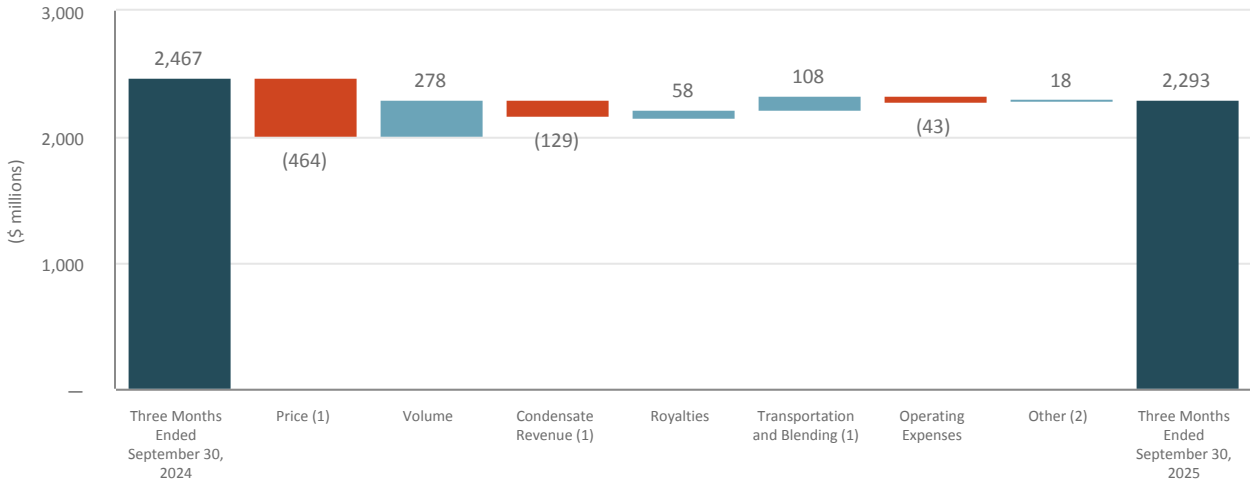
All major growth projects remain on track. We have completed the Narrows Lake tie-back to Christina Lake and are now ramping up production. The optimization project at Foster Creek was approximately 98 percent complete as at September 30, 2025, with four new steam generators brought online in the quarter, supporting higher production ahead of schedule. Commissioning of the water treating and de-oiling units is underway and new well pads will be brought online in early 2026. At Sunrise, we are preparing a well pad for steaming in the fourth quarter to support continued production growth. We continue to progress the Lloydminster conventional heavy oil drilling program.

Financial Results

($ millions)	Three Months Ended September 30, 2025	Three Months Ended September 30, 2024	Nine Months Ended September 30, 2025	Nine Months Ended September 30, 2024
Gross Sales				
External Sales	**5,177**	5,456	**15,874**	16,525
Intersegment Sales	**1,571**	1,719	**5,241**	4,831
	6,748	7,175	**21,115**	21,356
Royalties	**(831)**	(889)	**(2,281)**	(2,400)
Revenues	**5,917**	6,286	**18,834**	18,956
Expenses				
Purchased Product	**507**	629	**1,995**	1,321
Transportation and Blending	**2,452**	2,579	**8,138**	8,265
Operating	**655**	621	**2,032**	1,896
Realized (Gain) Loss on Risk Management	**10**	(10)	**10**	23
Operating Margin	**2,293**	2,467	**6,659**	7,451
Unrealized (Gain) Loss on Risk Management	**(12)**	(1)	**(3)**	(13)
Depreciation, Depletion and Amortization	**867**	784	**2,450**	2,330
Exploration Expense	**1**	2	**7**	6
(Income) Loss from Equity-Accounted Affiliates	**—**	—	**(38)**	(14)
Segment Income (Loss)	**1,437**	1,682	**4,243**	5,142

Operating Margin Variance

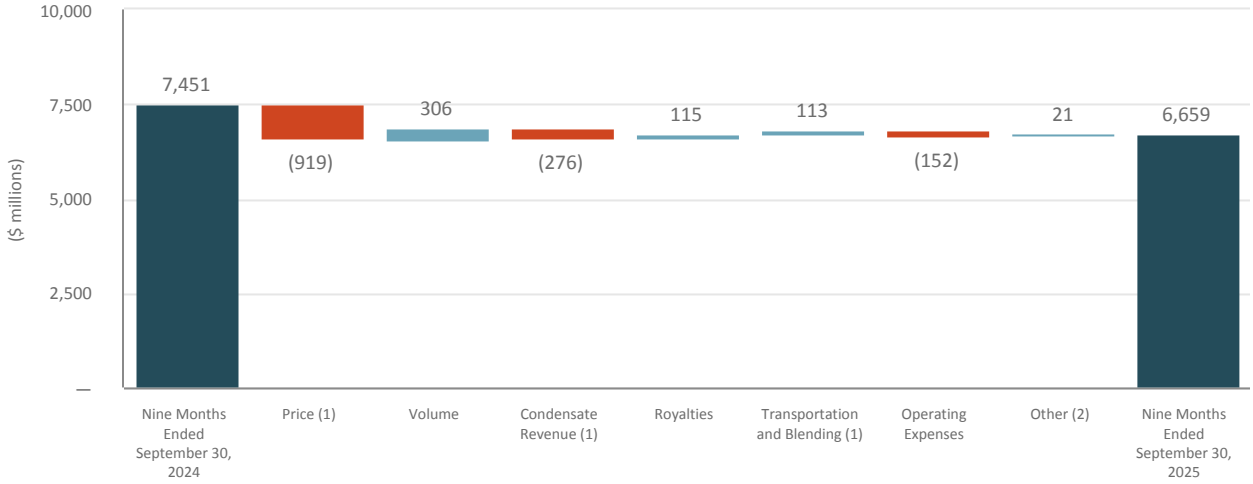
Three Months Ended September 30, 2025



(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 or natural gas.

Nine Months Ended September 30, 2025



(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 or natural gas.

Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	**2025**	2024
Total Sales Volumes [1] (MBOE/d)	**633.5**	595.3	**612.8**	596.3
Crude Oil Production by Asset (Mbbls/d)				
Foster Creek	**215.4**	198.0	**201.4**	196.3
Christina Lake	**251.7**	211.8	**235.8**	228.4
Sunrise	**52.4**	50.4	**51.6**	48.4
Lloydminster Thermal	**95.7**	109.4	**101.1**	112.3
Lloydminster Conventional Heavy Oil	**25.4**	16.3	**24.1**	17.4
Total Crude Oil Production [2] (Mbbls/d)	**640.6**	585.9	**614.0**	602.8
Natural Gas [1] (MMcf/d)	**13.7**	10.4	**13.9**	10.9
Total Production (MBOE/d)	**642.8**	587.7	**616.4**	604.8
Effective Royalty Rate [3] (percent)				
Foster Creek	**25.4**	25.9	**23.7**	24.0
Christina Lake	**27.9**	27.7	**26.4**	26.2
Sunrise	**5.3**	7.0	**6.0**	6.2
Lloydminster [4]	**11.9**	14.3	**12.1**	10.9
Total Effective Royalty Rate	**21.9**	22.4	**20.8**	20.4
Netback [5] ($/bbl)				
Realized Sales Price	**74.07**	81.77	**75.43**	81.01
Royalties	**14.28**	16.26	**13.66**	14.68
Transportation and Blending	**9.02**	9.18	**9.67**	8.89
Operating	**11.21**	11.17	**12.14**	11.50
Total Netback ($/bbl)	**39.56**	45.16	**39.96**	45.94
Per-Unit DD&A [6] ($/BOE)	**13.91**	13.62	**13.94**	13.53

(1) Bitumen, heavy crude oil and natural gas. Natural gas is a conventional natural gas product type.

(2) Oil Sands production is primarily bitumen, except for Lloydminster conventional heavy oil, which is heavy crude oil.

(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) Composed of Lloydminster thermal and Lloydminster conventional heavy oil assets.

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

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

Revenues

Gross sales decreased for the three months ended September 30, 2025, compared with 2024, due to lower Realized Sales Prices, partially offset by higher sales volumes. Gross sales were consistent for the nine months ended September 30, 2025, compared with 2024.

Price

Our bitumen and heavy oil 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 bitumen and heavy oil sales price decreases.

Our Realized Sales Price averaged $74.07 per barrel and $75.43 per barrel, respectively, in the three and nine months ended September 30, 2025, (2024 – $81.77 per barrel and $81.01 per barrel, respectively) mainly due to a lower WTI benchmark price, partially offset by a narrower WTI-WCS differential.

For the three and nine months ended September 30, 2025, approximately 36 percent and 38 percent, respectively (2024 – approximately 38 percent and 31 percent, respectively), of our sales volumes were sold at destinations outside of Alberta. Approximately 25 percent of our sales volumes were sold to our downstream operations in both the three and nine months ended September 30, 2025 (2024 – approximately 25 percent and 20 percent, respectively).

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

Oil Sands crude oil production increased in the three months ended September 30, 2025, compared with 2024, primarily due to:

- Optimization activities and the ramp-up of well pads at our Foster Creek, Lloydminster thermal, Sunrise and Christina Lake assets.
- Strong base production and additional volumes from new development wells at our Lloydminster conventional heavy oil assets.
- The ramp-up of production at Narrows Lake.

In the third quarter of 2024, production volumes were lower due to the completion of a turnaround at Christina Lake.

The increases in the quarter were partially offset by the temporary shut-in of production at our Rush Lake facilities as we respond to and recover from a casing failure at a steam injection well that occurred in the second quarter of 2025. Plans to safely commence and ramp-up production are expected by the end of the year.

Oil Sands crude oil production increased in the nine months ended September 30, 2025, compared with 2024, due to the factors discussed above, partially offset by:

- Turnaround activities at Foster Creek in the second quarter of 2025 and turnaround activities at Sunrise in the second and third quarters of 2025.
- The temporary shut-in of production at Christina Lake in response to wildfire activity in the second quarter of 2025.

Royalties

Our Alberta oil sands royalty projects are based on government prescribed pre- and post-payout royalty rates. 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.

Refer to our 2024 annual MD&A for further details.

In the three and nine months ended September 30, 2025, Oil Sands royalties decreased compared with 2024, mainly due to lower realized pricing, partially offset by higher sales volumes. For the three months ended September 30, 2025, the Oil Sands effective royalty rate decreased, primarily due to lower Alberta sliding scale oil sands royalty rates. For the nine months ended September 30, 2025, the Oil Sands effective royalty rate increased, primarily due to annual adjustments in 2024, partially offset by lower Alberta sliding scale oil sands royalty rates.

Expenses

Transportation and Blending

In the three and nine months ended September 30, 2025, blending expenses were $1.9 billion and $6.5 billion, respectively (2024 – $2.0 billion and $6.7 billion, respectively). The decrease for both periods was primarily due to lower condensate prices, partially offset by higher sales volumes.

Transportation expenses were consistent for the three months ended September 30, 2025, compared with 2024, as the increase in sales volumes was offset by a decrease in per-unit transportation expenses. Per-unit transportation expenses slightly decreased in the three months ended September 30, 2025, compared with 2024, due to lower sales volumes at U.S. and West Coast destinations. Transportation expenses and per-unit transportation expenses increased in the nine months ended September 30, 2025, compared with 2024, primarily due to higher sales volumes on TMX and increased pipeline transportation rates on shipments to U.S. destinations, partially offset by lower sales volumes at U.S. destinations.

Per-Unit Transportation Expenses [(1)]

	Three Months Ended September 30,		Nine Months Ended September 30,	
($/bbl)	**2025**	2024	**2025**	2024
Foster Creek	**13.13**	12.90	**15.67**	12.58
Christina Lake	**7.14**	7.63	**6.47**	6.69
Sunrise	**14.97**	15.36	**16.06**	17.41
Lloydminster [(2)]	**3.24**	3.63	**3.31**	4.02
Total Oil Sands	**9.02**	9.18	**9.67**	8.89

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

At Foster Creek, per-unit transportation expenses increased in the three and nine months ended September 30, 2025, compared with 2024, primarily due to higher sales to U.S. destinations. The quarter-over-quarter increase was partially offset by lower use of TMX. The year-over-year cost increase was also due to higher use of TMX, partially offset by lower rail costs. In the three and nine months ended September 30, 2025, 37 percent and 39 percent, respectively, of our sales volumes were sold at U.S. destinations (2024 – 32 percent and 35 percent, respectively). In the three and nine months ended September 30, 2025, 31 percent and 33 percent, respectively, of our sales volumes were sold at West Coast destinations (2024 – 34 percent and 15 percent, respectively).

At Christina Lake, per-unit transportation expenses decreased in the three and nine months ended September 30, 2025, compared with 2024, primarily due to lower sales volumes at U.S. destinations. In the three and nine months ended September 30, 2025, we shipped 17 percent and 16 percent, respectively, of our sales volumes to U.S. destinations (2024 – 24 percent and 19 percent, respectively).

At Sunrise, per-unit transportation expenses decreased in the three and nine months ended September 30, 2025, compared with 2024, primarily due to lower sales volumes at U.S. destinations, partially offset by higher use of TMX. In the three and nine months ended September 30, 2025, 47 percent and 57 percent, respectively, of our sales volumes were sold at West Coast destinations (2024 – 38 percent and 20 percent, respectively). In the three and nine months ended September 30, 2025, 37 percent and 34 percent, respectively, of our sales volumes were sold at U.S. destinations (2024 – 50 percent and 72 percent, respectively).

At Lloydminster, per-unit transportation expenses decreased in the three and nine months ended September 30, 2025, compared with 2024, primarily due to lower sales volumes at U.S. destinations. In the three and nine months ended September 30, 2025, we shipped less than one percent and two percent, respectively, of our sales volumes to U.S. destinations (2024 – one percent and four percent, respectively).

Operating

Primary drivers of our operating expenses in the first nine months of 2025 were fuel, repairs and maintenance, and workforce. Total operating expenses increased in the three and nine months ended September 30, 2025, compared with the same periods in 2024, primarily due to higher costs at our Lloydminster thermal assets related to the incident at Rush Lake and higher turnaround costs at Sunrise. Year-over-year also increased due to higher turnaround costs at Foster Creek.

Per-Unit Operating Expenses [1]

	Three Months Ended September 30,			Nine Months Ended September 30,		
($/bbl)	**2025**	**Percent Change**	2024	**2025**	**Percent Change**	2024
Foster Creek						
Fuel	**1.41**	**(7)**	1.52	**2.21**	**(1)**	2.24
Non-Fuel	**7.16**	**(4)**	7.49	**7.93**	**3**	7.72
Total	**8.57**	**(5)**	9.01	**10.14**	**2**	9.96
Christina Lake						
Fuel	**1.37**	**(3)**	1.41	**2.03**	**(1)**	2.05
Non-Fuel	**5.24**	**(34)**	7.92	**5.94**	**(12)**	6.72
Total	**6.61**	**(29)**	9.33	**7.97**	**(9)**	8.77
Sunrise						
Fuel	**2.50**	**38**	1.81	**3.76**	**27**	2.95
Non-Fuel	**14.95**	**34**	11.16	**14.63**	**30**	11.24
Total	**17.45**	**35**	12.97	**18.39**	**30**	14.19
Lloydminster [2]						
Fuel	**1.79**	**3**	1.74	**2.88**	**6**	2.71
Non-Fuel	**20.78**	**37**	15.17	**17.81**	**20**	14.88
Total	**22.57**	**33**	16.91	**20.69**	**18**	17.59
Total Oil Sands						
Fuel	**1.56**	**1**	1.55	**2.41**	**4**	2.32
Non-Fuel	**9.65**	**—**	9.62	**9.73**	**6**	9.18
Total	**11.21**	**—**	11.17	**12.14**	**6**	11.50

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

In the three months ended September 30, 2025, per-unit fuel expenses were relatively consistent compared with 2024, due to increased consumption volumes from well pads coming online at our Sunrise assets and lower sales volumes as a result of the incident at Rush Lake, offset by lower AECO benchmark pricing. In the nine months ended September 30, 2025, per-unit fuel expenses increased compared with 2024, due to increased consumption volumes and lower sales volumes, as discussed above, and higher AECO benchmark pricing.

Foster Creek per-unit non-fuel costs decreased in the three months ended September 30, 2025, compared with 2024, primarily due to higher sales volumes. Per-unit non-fuel costs increased in the nine months ended September 30, 2025, compared with 2024, primarily due turnaround activities in the second quarter of 2025, partially offset by higher sales volumes.

Christina Lake per-unit non-fuel costs decreased in the three and nine months ended September 30, 2025, compared with 2024, primarily due to lower turnaround expenses and higher sales volumes.

Sunrise per-unit non-fuel costs increased in the three and nine months ended September 30, 2025, compared with 2024, primarily due to turnaround activities in the second and third quarters of 2025.

Lloydminster per-unit non-fuel costs increased in the three and nine months ended September 30, 2025, compared with 2024, due to higher costs and lower sales volumes related to the Rush Lake incident.

MEG Acquisition and Asset Disposition

On August 21, 2025, we entered into a definitive agreement to acquire all of the issued and outstanding common shares of MEG through a plan of arrangement. On October 26, 2025, we entered into a second amending agreement. The MEG Acquisition is subject to shareholder, court and other customary approvals. The MEG Acquisition will expand our Christina Lake assets and is expected to add approximately 110.0 thousand barrels per day of production.

On October 26, 2025, we entered into an agreement to dispose of certain Lloydminster thermal assets in our Oil Sands segment, representing approximately 5.0 thousand barrels per day of production, for total proceeds of up to $150 million, including $75 million in cash paid on closing and up to $75 million in variable consideration. The disposition is expected to close in the fourth quarter of 2025, subject to closing conditions.

Conventional

In the third quarter of 2025, we:

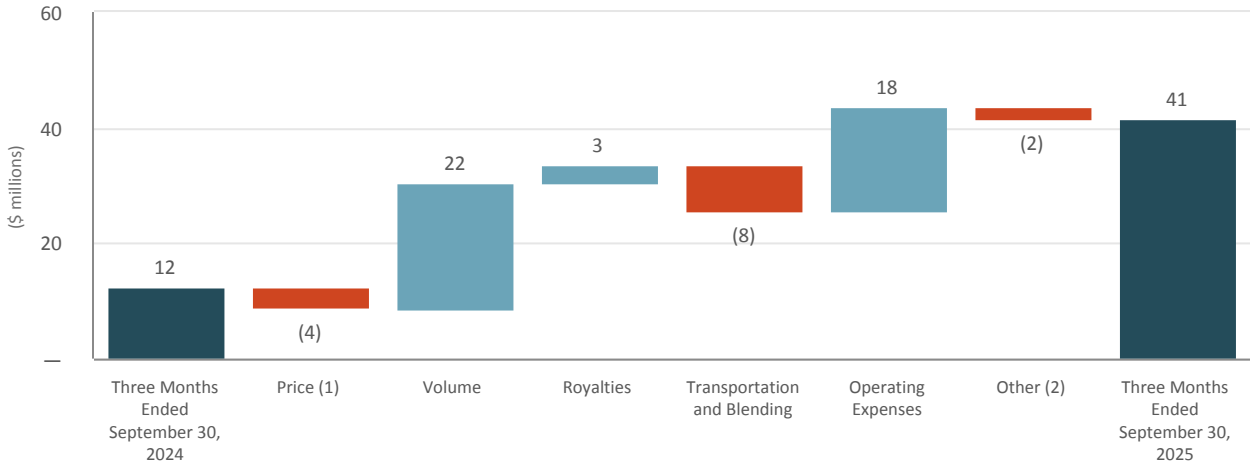
- Delivered safe and reliable operations.
- Produced 126.9 thousand BOE per day (2024 – 118.1 thousand BOE per day).
- Generated Operating Margin of $41 million, an increase of $29 million from 2024.
- Earned a Netback of $3.85 per BOE (2024 – $1.12 per BOE), primarily due to lower operating expenses.
- Invested capital of $107 million, primarily related to drilling, completion, tie-in and infrastructure projects.

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2025**	2024	**2025**	2024
Gross Sales				
External Sales	**212**	225	**936**	866
Intersegment Sales	**217**	488	**986**	1,417
	429	713	**1,922**	2,283
Royalties	**(12)**	(15)	**(44)**	(61)
Revenues	**417**	698	**1,878**	2,222
Expenses				
Purchased Product	**161**	459	**951**	1,353
Transportation and Blending	**86**	80	**259**	241
Operating	**127**	147	**369**	432
Realized (Gain) Loss on Risk Management	**2**	—	**1**	(7)
Operating Margin	**41**	12	**298**	203
Unrealized (Gain) Loss on Risk Management	**(6)**	2	**(7)**	10
Depreciation, Depletion and Amortization	**125**	109	**362**	330
(Income) Loss From Equity-Accounted Affiliates	**—**	—	**1**	1
Segment Income (Loss)	**(78)**	(99)	**(58)**	(138)

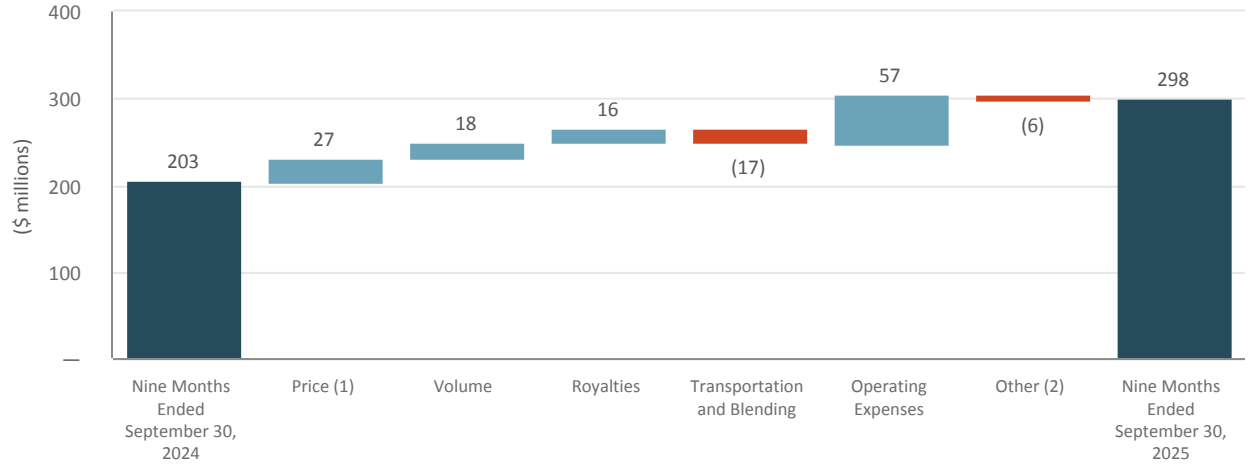
Operating Margin Variance

Three Months Ended September 30, 2025



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

Nine Months Ended September 30, 2025



(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,	
	2025	2024	**2025**	2024
Total Sales Volumes [1] (MBOE/d)	**126.9**	118.1	**123.6**	120.5
Realized Sales Price [1] [2] ($/BOE)				
Light Crude Oil ($/bbl)	**77.58**	93.68	**81.69**	93.18
NGLs ($/bbl)	**45.44**	53.77	**52.30**	55.84
Conventional Natural Gas ($/Mcf)	**2.01**	1.53	**2.95**	2.43
Production by Product [1]				
Light Crude Oil (Mbbls/d)	**5.0**	4.6	**4.9**	5.0
NGLs (Mbbls/d)	**23.0**	21.1	**21.3**	21.5
Conventional Natural Gas (MMcf/d)	**593.2**	554.8	**583.9**	564.8
Total Production (MBOE/d)	**126.9**	118.1	**123.6**	120.5
Conventional Natural Gas Production (percentage of total)	**78**	78	**79**	78
Crude Oil and NGLs Production (percentage of total)	**22**	22	**21**	22
Effective Royalty Rate [1] [3] (percent)	**9.3**	10.7	**8.6**	10.9
Netback [1] [2] ($/BOE)				
Realized Sales Price	**20.69**	20.42	**26.23**	25.18
Royalties	**1.04**	1.38	**1.35**	1.86
Transportation and Blending	**5.47**	5.15	**5.41**	5.03
Operating	**10.33**	12.77	**10.40**	12.35
Total Netback ($/BOE)	**3.85**	1.12	**9.07**	5.94
Per-Unit DD&A [4] ($/BOE)	**10.33**	9.97	**10.35**	9.89

(1) For the three and nine months ended September 30, 2025, reported production volumes, sales volumes, associated per-unit values and effective royalty rates reflect Cenovus's 30 percent equity interest in the Duvernay joint venture.
(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

Gross sales decreased in the three and nine months ended September 30, 2025, compared with 2024, due to lower commodity trading volumes sourced from third parties, partially offset by higher sales volumes and higher realized pricing.

Price

Our total Realized Sales Price increased for the three and nine months ended September 30, 2025, compared with 2024, primarily due to higher sales volumes to U.S. destinations. For the three and nine months ended September 30, 2025, 34 percent and 31 percent, respectively, of our natural gas sales volumes were sold at U.S. destinations (2024 – 29 percent for both periods), where NYMEX natural gas benchmark prices were higher. For the three and nine months ended September 30, 2025, NYMEX natural gas benchmark prices were US$3.07 per Mcf and US$3.39 per Mcf, respectively (2024 – US$2.16 per Mcf and US$2.10 per Mcf, respectively). The quarter-over-quarter increase was partially offset by AECO natural gas benchmark prices decreasing to $0.63 per Mcf (2024 – $0.69 per Mcf). The year-over-year increase was also due to AECO natural gas benchmark prices increasing to $1.50 per Mcf (2024 – $1.45 per Mcf).

Production Volumes

For the three and nine months ended September 30, 2025, production volumes increased compared with 2024, primarily due to strong performance from base and new development wells. In the third quarter of 2024, production volumes were lower due to turnaround activities in the period.

Royalties

Royalties and the effective royalty rate decreased in the three and nine months ended September 30, 2025, compared with 2024, primarily due to lower natural gas benchmark prices used to calculate our royalties.

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, 2025, transportation expenses and per-unit transportation expenses increased compared with 2024, due to increased pipeline transportation rates.

Operating

Primary drivers of operating expenses in the first nine months of 2025 were repairs and maintenance, workforce and property tax costs. Total operating expenses and per-unit operating expenses decreased in the three and nine months ended September 30, 2025, compared with 2024, primarily due to lower turnaround costs, and processing and gathering costs.

Offshore

In the third quarter of 2025, we:

- Delivered safe and reliable operations.
- Produced 63.2 thousand BOE per day of light crude oil, NGLs and natural gas (2024 – 65.5 thousand BOE per day).
- Generated Operating Margin of $256 million, an increase of $4 million from 2024.
- Averaged a Netback of $48.59 per BOE (2024 – $53.20 per BOE).
- Invested capital of $217 million mainly related to the progression of the West White Rose project.

In the quarter, the topsides were placed atop the concrete gravity structure, and we completed the subsea tie-ins to our existing production system at the *SeaRose* FPSO. The remainder of the platform hookup and commissioning work is expected to be completed in the fourth quarter. As at September 30, 2025, the project was approximately 98 percent complete. We are on track to begin drilling by the end of 2025 and deliver first oil in the second quarter of 2026. Since our decision in 2022 to restart the project, we have invested approximately $2.2 billion.

Financial Results

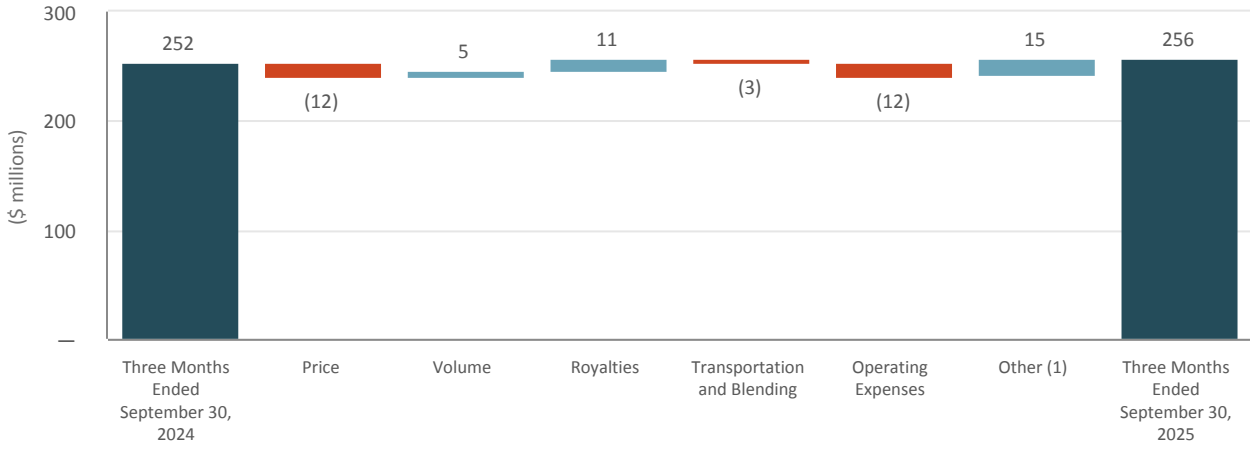
	Three Months Ended September 30,					
	2025			2024		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore**	Atlantic	Asia Pacific	Offshore
Gross Sales						
External Sales	**140**	**245**	**385**	71	300	371
Intersegment Sales	**—**	**—**	**—**	—	—	—
	140	**245**	**385**	71	300	371
Royalties	**(2)**	**(13)**	**(15)**	(1)	(24)	(25)
Revenues	**138**	**232**	**370**	70	276	346
Expenses						
Purchased Product	**6**	**—**	**6**	—	—	—
Transportation and Blending	**5**	**—**	**5**	2	—	2
Operating	**75**	**28**	**103**	58	34	92
Operating Margin [(1)]	**52**	**204**	**256**	10	242	252
Depreciation, Depletion and Amortization			**106**			134
Exploration Expense			**—**			42
(Income) Loss from Equity-Accounted Affiliates			**(9)**			(11)
Segment Income (Loss)			**159**			87

	Nine Months Ended September 30,					
	2025			2024		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore**	Atlantic	Asia Pacific	Offshore
Gross Sales						
External Sales	**358**	**813**	**1,171**	264	935	1,199
Intersegment Sales	**—**	**—**	**—**	—	—	—
	358	**813**	**1,171**	264	935	1,199
Royalties	**(4)**	**(56)**	**(60)**	(2)	(72)	(74)
Revenues	**354**	**757**	**1,111**	262	863	1,125
Expenses						
Purchased Product	**6**	**—**	**6**	—	—	—
Transportation and Blending	**14**	**—**	**14**	9	—	9
Operating	**187**	**86**	**273**	225	94	319
Operating Margin [(1)]	**147**	**671**	**818**	28	769	797
Depreciation, Depletion and Amortization			**329**			421
Exploration Expense			**2**			50
(Income) Loss from Equity-Accounted Affiliates			**(24)**			(34)
Segment Income (Loss)			**511**			360

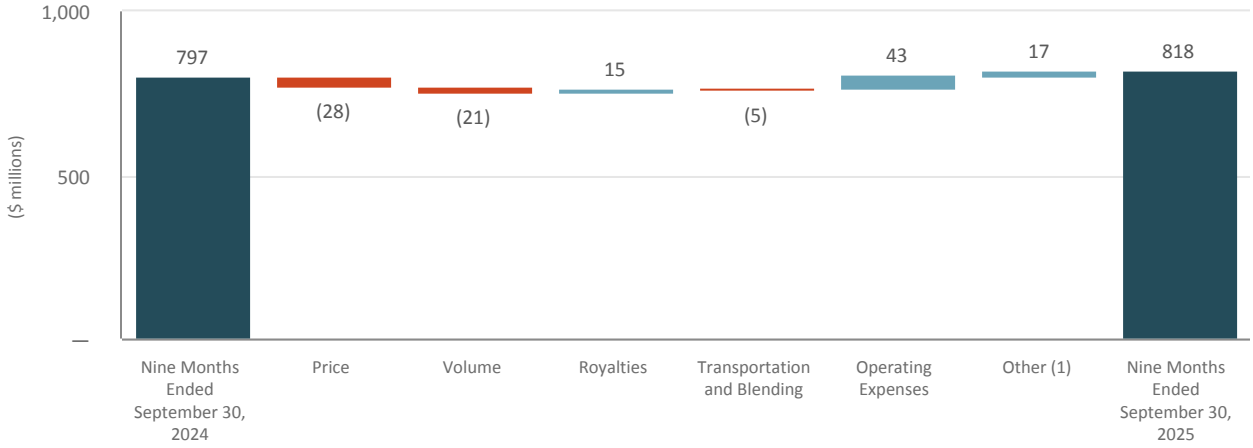
(1) Atlantic and Asia Pacific Operating Margin are non-GAAP financial measures. See the Specified Financial Measures Advisory of this MD&A.

Operating Margin Variance

Three Months Ended September 30, 2025



Nine Months Ended September 30, 2025



(1) Includes other activities not attributable to the production of crude oil and natural gas.

Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	**2025**	2024
Sales Volumes				
Atlantic (Mbbls/d)	**13.6**	7.2	**12.4**	8.6
Asia Pacific (MBOE/d)				
China	**35.2**	40.5	**38.1**	42.6
Indonesia [(1)]	**16.7**	16.0	**16.0**	14.8
Total Asia Pacific	**51.9**	56.5	**54.1**	57.4
Total Sales Volumes (MBOE/d)	**65.5**	63.7	**66.5**	66.0

(1) Reported sales volumes reflect Cenovus's 40 percent equity interest in the HCML joint venture.

Operating Results — Continued

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	**2025**	2024
Production by Product				
Atlantic – Light Crude Oil (Mbbls/d)	**11.3**	9.0	**11.8**	8.2
Asia Pacific [1]				
NGLs (Mbbls/d)	**4.8**	9.9	**7.8**	10.7
Conventional Natural Gas (MMcf/d)	**282.6**	279.4	**278.5**	280.1
Total Asia Pacific (MBOE/d)	**51.9**	56.5	**54.1**	57.4
Total Production (MBOE/d)	**63.2**	65.5	**65.9**	65.6
Effective Royalty Rate [2] (percent)				
Atlantic	**1.0**	1.0	**1.0**	0.6
Asia Pacific [1]	**10.4**	8.7	**11.7**	8.6
Per-Unit DD&A [3] ($/BOE)	**15.95**	22.16	**17.06**	22.51

(1) Reported production volumes and royalty rates reflect Cenovus's 40 percent equity interest in the HCML joint venture.
(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.

Netbacks [1]

	Three Months Ended September 30, 2025			
($/BOE, except where indicated)	**Atlantic** ($/bbl)	**China**	**Indonesia**	**Total Offshore** [2]
Realized Sales Price	**95.29**	**75.41**	**55.57**	**74.50**
Royalties	**0.96**	**4.03**	**13.77**	**5.87**
Transportation and Blending	**4.07**	**—**	**—**	**0.85**
Operating Expenses	**59.90**	**8.26**	**8.89**	**19.19**
Netback	**30.36**	**63.12**	**32.91**	**48.59**

	Three Months Ended September 30, 2024			
($/BOE, except where indicated)	Atlantic ($/bbl)	China	Indonesia	Total Offshore [2]
Realized 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

	Nine Months Ended September 30, 2025			
($/BOE, except where indicated)	**Atlantic** ($/bbl)	**China**	**Indonesia**	**Total Offshore** [2]
Realized Sales Price	**99.41**	**77.79**	**59.59**	**77.46**
Royalties	**0.99**	**5.40**	**15.85**	**7.08**
Transportation and Blending	**4.16**	**—**	**—**	**0.78**
Operating Expenses	**54.19**	**7.59**	**10.01**	**16.86**
Netback	**40.07**	**64.80**	**33.73**	**52.74**

	Nine Months Ended September 30, 2024			
($/BOE, except where indicated)	Atlantic ($/bbl)	China	Indonesia	Total Offshore [2]
Realized 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

(1) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Reported per-unit values reflect Cenovus's 40 percent equity interest in the HCML joint venture.

Revenues

For the three months ended September 30, 2025, gross sales increased compared with 2024, due to higher Atlantic sales volumes, partially offset by lower Realized Sales Prices. For the nine months ended September 30, 2025, gross sales decreased slightly compared with 2024, primarily due to lower Realized Sales Prices.

Price

Our Atlantic Realized Sales Price decreased in the three and nine months ended September 30, 2025, compared with 2024, due to lower Brent benchmark pricing. The prices we receive for natural gas sold in Asia Pacific are set under long-term contracts.

Production Volumes

Atlantic production increased in the three and nine months ended September 30, 2025, compared with 2024, primarily due to the ramp-up of production at the White Rose field early in the second quarter of 2025. Atlantic production was lower in the same periods in 2024, as production at the White Rose field was suspended in late December 2023 in preparation for the *SeaRose* ALE project. Operations resumed and production restarted safely in the first quarter of 2025. The quarter-over-quarter increase was partially offset by decreased production at the Terra Nova field and turnaround activities at *SeaRose* while we completed subsea tie-ins. Light crude oil production from the White Rose and Terra Nova fields are offloaded from the *SeaRose* and *Terra Nova* FPSO vessels, respectively, to tankers and stored at an onshore terminal before shipment to buyers, which results in a timing difference between production and sales.

Asia Pacific production decreased in the three and nine months ended September 30, 2025, compared with 2024, primarily due to lower contracted sales volumes in China, partially offset by increased production in Indonesia due to higher buyer nominations. The quarter-over-quarter decrease was also due to maintenance activities in China.

Royalties

For the three months ended September 30, 2025, the Atlantic effective royalty rate was consistent compared with 2024. For the nine months ended September 30, 2025, the Atlantic effective royalty rate increased compared with 2024, primarily due to a credit received in the second quarter of 2024.

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

Expenses

Transportation

Transportation expenses include the costs of transporting crude oil from the *SeaRose* and *Terra Nova* FPSOs to onshore terminals and storage costs. Transportation expenses for the three and nine months ended September 30, 2025, increased to $5 million and $14 million, respectively (2024 – $2 million and $9 million, respectively), primarily due to higher sales volumes.

Operating

Primary drivers of our Atlantic operating expenses in the first nine months of 2025 were repairs and maintenance, costs related to vessels and air services, and workforce. In the three months ended September 30, 2025, operating expenses increased compared with 2024, primarily due to higher sales volumes. In the nine months ended September 30, 2025, operating expenses decreased compared with 2024, due to lower repairs and maintenance, and vessels and air service costs as the *SeaRose* ALE project was completed in the first quarter of 2025. In the three and nine months ended September 30, 2025, per-unit operating expenses decreased compared with 2024, due to higher sales volumes and lower costs related to the *SeaRose* ALE project, as discussed above.

Primary drivers of our China operating expenses in the first nine months of 2025 were repairs and maintenance, workforce and insurance costs. Per-unit operating expenses increased in the three and nine months ended September 30, 2025, compared with 2024, primarily due to lower sales volumes, partially offset by lower insurance costs. The quarter-over-quarter increase was also partially offset by lower repairs and maintenance costs.

Primary drivers of our Indonesia operating expenses in the first nine months of 2025 were repairs and maintenance, and workforce costs. Indonesia per-unit operating expenses decreased in the three and nine months ended September 30, 2025, compared with 2024, due to higher sales volumes. The quarter-over-quarter decrease was also due to lower repairs and maintenance costs. The year-over-year decrease was partially offset by higher repairs and maintenance costs.

DOWNSTREAM

Canadian Refining

In the third quarter of 2025, we:

- Delivered safe and reliable operations.
- Achieved crude oil throughput of 105.4 thousand barrels per day and crude unit utilization of 98 percent (2024 – 99.4 thousand barrels per day and 92 percent, respectively).
- Incurred per-unit operating expenses excluding turnaround costs of $11.38 per barrel (2024 – $12.22 per barrel).
- Recorded Operating Margin of $111 million, an increase of $51 million from the third quarter of 2024. The increase was primarily due to lower operating costs and lower feedstock costs due to lower benchmark crude pricing, partially offset by lower refined product pricing and the narrowing of the WCS-WTI differential.
- Invested capital of $33 million, primarily focused on sustaining activities.

Financial and Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2025**	2024	**2025**	2024
Revenues	**1,353**	1,580	**3,923**	4,047
Purchased Product	**1,102**	1,353	**3,218**	3,415
Gross Margin [(1)]	**251**	227	**705**	632
Expenses				
Operating	**140**	167	**419**	759
Operating Margin	**111**	60	**286**	(127)
Depreciation, Depletion and Amortization	**40**	49	**139**	147
Segment Income (Loss)	**71**	11	**147**	(274)

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions, except where indicated)	**2025**	2024	**2025**	2024
Gross Margin	**251**	227	**705**	632
Add (Deduct):				
Inventory Holding (Gain) Loss [(1)]	**8**	16	**(1)**	(2)
Adjusted Gross Margin [(2)]	**259**	243	**704**	630
Adjusted Refining Margin [(3)] ($/bbl)	**21.76**	22.17	**19.56**	22.27

(1) Inventory holding (gain) loss reflects the difference between the cost of volumes produced at current-period costs and the cost of volumes produced under the first-in, first-out ("FIFO") or weighted average cost basis, as required by IFRS Accounting Standards.
(2) Non-GAAP 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. Revenues from the Upgrader, the Lloydminster Refinery and the commercial fuels business for the three and nine months ended September 30, 2025, were $1.3 billion and $3.7 billion, respectively (2024 – $1.5 billion and $3.8 billion, respectively).

Revenues, Adjusted Gross Margin and Adjusted Refining Margin

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

The Lloydminster Refinery processes blended heavy crude oil into asphalt, bulk distillates 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.

Revenues decreased in the three and nine months ended September 30, 2025, compared with 2024, primarily due to lower refined product pricing.

Adjusted Gross Margin increased in the three and nine months ended September 30, 2025, compared with the same periods in 2024, primarily due to lower feedstock costs as a result of lower benchmark crude pricing, partially offset by lower refined product pricing and the narrowing of the WTI-WCS differential.

Adjusted Refining Margin decreased in the three and nine months ended September 30, 2025, as the increase in Adjusted Gross Margin, as discussed above, was more than offset by the increase in total processed inputs.

(Mbbls/d, except where indicated)	Three Months Ended September 30, 2025	2024	Nine Months Ended September 30, 2025	2024
Operable Capacity	**108.0**	108.0	**108.0**	108.0
Total Processed Inputs	**114.8**	106.4	**118.3**	91.4
Crude Oil Unit Throughput	**105.4**	99.4	**109.9**	85.8
Crude Unit Utilization (percent)	**98**	92	**102**	79
Total Production	**122.3**	113.6	**126.0**	98.0
Synthetic Crude Oil	**48.3**	47.3	**52.0**	38.4
Asphalt	**19.5**	16.5	**17.6**	15.4
Diesel	**14.2**	11.8	**14.9**	10.0
Other	**35.0**	32.5	**36.6**	29.1
Ethanol	**5.3**	5.5	**4.9**	5.1

The Upgrader and Lloydminster Refinery source their crude oil feedstock from our Oil Sands segment. In the three and nine months ended September 30, 2025, 14 percent and 15 percent, respectively, of our Oil Sands segment's sales volumes were purchased by our Canadian Refining segment (2024 – 14 percent and 11 percent, respectively).

Throughput and total production increased in the three and nine months ended September 30, 2025, compared with 2024. In 2025, our assets ran near, or above full capacity due to ongoing improvement initiatives and high asset reliability. In the second quarter of 2024, we safely completed the largest turnaround in the history of the Upgrader, which decreased throughput and increased operating expenses.

Operating Expenses

The following table and discussion represent operating expenses associated with the Upgrader, the Lloydminster Refinery and the commercial fuels business.

($ millions, except where indicated)	Three Months Ended September 30, 2025	2024	Nine Months Ended September 30, 2025	2024
Operating Expenses – Upgrading and Refining	**120**	143	**354**	667
Operating Expenses – Excluding Turnaround Costs	**120**	119	**353**	417
Operating Expenses – Turnaround Costs	**—**	24	**1**	250
Per-Unit Operating Expenses [(1)] ($/bbl)	**11.38**	14.63	**10.96**	26.65
Per-Unit Operating Expenses – Excluding Turnaround Costs	**11.38**	12.22	**10.93**	16.67
Per-Unit Operating Expenses – Turnaround Costs	**—**	2.41	**0.03**	9.98

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

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

In the three and nine months ended September 30, 2025, operating expenses decreased compared with the same periods in 2024, mainly due to lower turnaround costs and other project costs. Turnaround costs and other project costs were higher in the same periods in 2024, due to the turnaround completed at the Upgrader.

Operating expenses excluding turnaround costs were relatively consistent in the three months ended September 30, 2025, compared with 2024. Operating expenses excluding turnaround costs decreased in the nine months ended September 30, 2025, compared with 2024, due to lower project costs.

In the three and nine months ended September 30, 2025, the decrease in operating expenses, combined with increased total processed inputs, resulted in decreased per-unit operating metrics compared with 2024.

U.S. Refining

In the third quarter of 2025, we:

- Delivered safe and reliable operations.
- Achieved record throughput of 605.3 thousand barrels per day compared with 543.5 thousand barrels per day in the third quarter of 2024, and crude unit utilization of 99 percent (2024 – 89 percent).
- Decreased per-unit operating expenses excluding turnaround costs to $9.67 per barrel (2024 – $12.74 per barrel).
- Recorded Operating Margin of $253 million, an increase of $636 million from the third quarter of 2024, primarily due to higher market crack spreads, lower operating expenses, increased sales volumes and the receipt of Small Refinery Exemption ("SRE") waivers.
- Invested capital of $120 million, primarily focused on reliability and sustaining activities.
- Divested our 50 percent interest in WRB.

Financial and Operating Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2025**	2024	**2025**	2024
Revenues [1]	**7,082**	7,218	**19,960**	21,734
Purchased Product [1]	**6,219**	6,854	**18,063**	19,473
Gross Margin [2]	**863**	364	**1,897**	2,261
Expenses				
Operating	**611**	751	**2,133**	2,045
Realized (Gain) Loss on Risk Management	**(1)**	(4)	**(6)**	5
Operating Margin	**253**	(383)	**(230)**	211
Unrealized (Gain) Loss on Risk Management	**3**	5	**(5)**	3
Depreciation, Depletion and Amortization	**160**	115	**467**	338
Segment Income (Loss)	**90**	(503)	**(692)**	(130)

(1) Comparative periods reflect certain revisions. See the Prior Period Revisions section of this MD&A for further details.
(2) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions, except where indicated)	**2025**	2024	**2025**	2024
Gross Margin	**863**	364	**1,897**	2,261
Add (Deduct):				
Inventory Holding (Gain) Loss [1]	**80**	209	**165**	(68)
Adjusted Gross Margin [2]	**943**	573	**2,062**	2,193
Adjusted Refining Margin [2] ($/bbl)	**15.92**	10.97	**12.45**	13.82
Adjusted Market Capture [2] (percent)	**65**	54	**62**	70

(1) Inventory holding (gain) loss reflects the difference between the cost of volumes produced at current-period costs and the cost of volumes produced under the FIFO or weighted average cost basis, as required by IFRS Accounting Standards.
(2) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

Revenues

Revenues decreased in the three and nine months ended September 30, 2025, compared with 2024, primarily due to lower refined product pricing, partially offset by higher sales volumes in the three months ended September 30, 2025.

Adjusted Gross Margin, Adjusted Refining Margin and Adjusted Market Capture

Benchmark market crack spreads do not precisely mirror the refinery configuration for crude diet and product yields, or the location we sell product; however, they are used as a general market indicator.

In the three months ended September 30, 2025, the Chicago 3-2-1 crack spread increased 30 percent and the Group 3 3-2-1 crack spread increased 25 percent compared with 2024. The increase in crack spreads was partially offset by an increase in the average cost of RINs of 63 percent. Quarter-over-quarter, Adjusted Gross Margin increased due to the increase in the weighted average crack spread, net of RINs, higher sales volumes and the receipt of SRE waivers.

In the nine months ended September 30, 2025, the Chicago 3-2-1 crack spread increased nine percent and the Group 3 3-2-1 crack spread increased 16 percent compared with 2024. The increase in crack spreads were largely offset by an increase in the average cost of RINs of 57 percent, which contributed to a slight increase in weighted average crack spreads, net of RINs. Year-over-year, Adjusted Gross Margin decreased due to the narrowing of the WTI-WCS differential impacting our feedstock costs, partially offset by a slight increase in the weighted average crack spreads, net of RINs.

Adjusted Refining Margin, which is the Adjusted 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; and the cost of feedstock.

Adjusted Refining Margin and Adjusted Market Capture increased in the three months ended September 30, 2025, compared with the same period in 2024, due to the increase in Adjusted Gross Margin and improved process unit utilization at our operated refineries.

Adjusted Refining Margin and Adjusted Market Capture decreased in the nine months ended September 30, 2025, compared with the same period in 2024, due to the decrease in Adjusted Gross Margin and higher total processed inputs. While the turnaround at the Toledo Refinery, completed during the second quarter of 2025 impacted the Adjusted Refining Margin and Adjusted Market Capture, this was offset by ongoing operational improvements in our operated U.S. Refining business.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Mbbls/d, except where indicated)	**2025**	2024	**2025**	2024
Operable Capacity	**612.3**	612.3	**612.3**	612.3
Total Processed Inputs	**642.8**	568.0	**606.2**	579.0
Crude Oil Unit Throughput	**605.3**	543.5	**571.0**	554.5
Heavy Crude Oil	**224.7**	215.7	**221.7**	219.9
Light/Medium Crude Oil	**380.6**	327.8	**349.3**	334.6
Crude Unit Utilization (percent)	**99**	89	**93**	91
Total Refined Product Production	**648.0**	571.6	**615.1**	585.3
Gasoline	**304.7**	259.7	**288.9**	273.4
Distillates [(1)]	**233.4**	205.3	**216.5**	206.7
Asphalt	**28.2**	29.6	**26.1**	28.0
Other	**81.7**	77.0	**83.6**	77.2

(1) Includes diesel and jet fuel.

Throughput and refined product production increased in the three and nine months ended September 30, 2025, compared with the same periods in 2024. The increase was primarily due to improved process unit utilization across our operated refineries driven by ongoing operational improvements made to the U.S. Refining business. In the three and nine months ended September 30, 2024, throughput and refined product production were lower, and operating expenses were higher due to the turnaround at the Lima Refinery, which was completed in October 2024.

Operating Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions, except where indicated)	**2025**	2024	**2025**	2024
Operating Expenses	**611**	751	**2,133**	2,045
Operating Expenses – Excluding Turnaround Costs	**573**	666	**1,776**	1,868
Operating Expenses – Turnaround Costs	**38**	85	**357**	177
Per-Unit Operating Expenses [(1)] ($/bbl)	**10.32**	14.37	**12.89**	12.89
Per-Unit Operating Expenses – Excluding Turnaround Costs	**9.67**	12.74	**10.73**	11.77
Per-Unit Operating Expenses – Turnaround Costs	**0.65**	1.63	**2.16**	1.12

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

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

In the three months ended September 30, 2025, operating expenses decreased due to a decrease in turnaround costs, repairs and maintenance, and project costs, compared with 2024. In the third quarter of 2024, the Lima Refinery turnaround commenced, as discussed above.

In the nine months ended September 30, 2025, operating expenses increased compared with 2024. This was mainly due to the turnaround costs recognized in the first half of the year at the Toledo Refinery and the non-operated Wood River and Borger refineries, partially offset by lower repairs and maintenance, and project costs.

Operating expenses excluding turnaround costs and related per-unit metrics for the three and nine months ended September 30, 2025, decreased compared with 2024, primarily due to lower controllable operating expenses, including lower repairs and maintenance, and project costs, as well as the positive benefits of ongoing business improvement initiatives and improved reliability in our operated downstream assets. The decrease in operating expenses was partially offset by higher electricity costs and foreign exchange impacts from a slight weakening of the Canadian dollar, on average, relative to the U.S. dollar.

CORPORATE AND ELIMINATIONS

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2025**	2024	**2025**	2024
Realized (Gain) Loss on Risk Management	**6**	(13)	**(19)**	(10)
Unrealized (Gain) Loss on Risk Management	**(4)**	1	**(50)**	31
General and Administrative	**220**	172	**570**	593
Finance Costs, Net	**154**	118	**404**	394
Integration, Transaction and Other Costs	**44**	41	**123**	113
Foreign Exchange (Gain) Loss, Net	**157**	(73)	**(196)**	81
(Gain) Loss on Divestiture of Assets	**(106)**	(17)	**(109)**	(121)
Other (Income) Loss, Net	**(22)**	(28)	**(54)**	(158)

General and Administrative

Primary drivers of our general and administrative expenses for the three and nine months ended September 30, 2025, were workforce and information technology related costs. For the three months ended September 30, 2025, general and administrative costs increased compared with 2024, due to higher long-term incentive costs. For the nine months ended September 30, 2025, general and administrative costs decreased compared with 2024, due to general cost saving initiatives.

Finance Costs, Net

Net finance costs were higher in the three months ended September 30, 2025, compared with the same period in 2024, due to lower interest income. Net finance costs slightly increased in the nine months ended September 30, 2025, compared with the same period 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, 2025, was 4.52 percent and 4.53 percent, respectively (2024 – 4.54 and 4.50 percent, respectively).

Foreign Exchange (Gain) Loss, Net

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2025**	2024	**2025**	2024
Unrealized Foreign Exchange (Gain) Loss	**153**	(108)	**(248)**	101
Realized Foreign Exchange (Gain) Loss	**4**	35	**52**	(20)
	157	(73)	**(196)**	81

For the three and nine months ended September 30, 2025, unrealized foreign exchange losses and gains were primarily due to the translation of U.S. denominated debt. Realized foreign exchange losses were primarily related to working capital. As at September 30, 2025, the Canadian dollar weakened relative to the U.S. dollar as at June 30, 2025, and strengthened relative to the U.S. dollar as at December 31, 2024. As at September 30, 2024, the Canadian dollar strengthened relative to the U.S. dollar as at June 30, 2024, and weakened relative to the U.S. dollar as at December 31, 2023.

(Gain) Loss on Divestiture of Assets

In the three months ended September 30, 2025, the Company recorded a before-tax gain of $106 million related to the divestiture of our 50 percent interest in WRB.

In the three and nine months ended September 30, 2024, we recorded gains on the divestiture of assets related to Duvernay, and the sale of non-core assets in our Conventional segment.

Income Taxes

($ millions)	Three Months Ended September 30, 2025	2024	Nine Months Ended September 30, 2025	2024
Current Tax				
Canada	**288**	184	**791**	830
United States	**—**	—	**—**	2
Asia Pacific	**42**	57	**144**	157
Other International	**8**	9	**32**	26
Total Current Tax Expense (Recovery)	**338**	250	**967**	1,015
Deferred Tax Expense (Recovery)	**(327)**	(46)	**(520)**	(124)
	11	204	**447**	891

For the nine months ended September 30, 2025, the Company recorded a deferred tax recovery, of which $315 million related to the divestiture of our 50 percent interest in WRB.

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.

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.

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.

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. Our other sources of liquidity include 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.

($ millions)	Three Months Ended September 30, 2025	2024	Nine Months Ended September 30, 2025	2024
Cash From (Used In)				
Operating Activities	**2,131**	2,474	**5,820**	7,206
Investing Activities	**(1,316)**	(1,308)	**(4,039)**	(3,613)
Net Cash Provided (Used) Before Financing Activities	**815**	1,166	**1,781**	3,593
Financing Activities	**(1,519)**	(1,175)	**(2,891)**	(2,764)
Effect of Foreign Exchange on Cash and Cash Equivalents	**42**	(41)	**(82)**	48
Increase (Decrease) in Cash and Cash Equivalents	**(662)**	(50)	**(1,192)**	877

As at ($ millions)	September 30, 2025	December 31, 2024
Cash and Cash Equivalents	**1,901**	3,093
Total Debt	**7,156**	7,707

Cash From (Used in) Operating Activities

In the three and nine months ended September 30, 2025, cash from operating activities decreased compared with the same periods in 2024. Quarter-over-quarter, the decrease was primarily due to changes in non-cash working capital, partially offset by higher Operating Margin. Year-over-year, the decrease was due to changes in non-cash working capital and lower Operating Margin.

For the three months ended September 30, 2025, changes in non-cash working capital decreased cash from operating activities by $241 million, primarily due to changes in accounts payable and accounts receivable, excluding the impact of the divestiture of WRB.

For the nine months ended September 30, 2025, changes in non-cash working capital decreased cash from operating activities by $179 million, primarily due to changes in accounts receivable and income tax payable, partially offset by changes in inventories, excluding the impact of the divestiture of WRB.

Cash From (Used in) Investing Activities

Cash used in investing activities was relatively consistent in the three months ended September 30, 2025, and increased in the first nine months of 2025, compared with 2024. Cash used in investing activities primarily relates to capital investment.

Cash From (Used in) Financing Activities

Cash used in financing activities increased in the three and nine months ended September 30, 2025, compared with the same periods in 2024.

Quarter-over-quarter, the increase was primarily due to purchases under the Company's NCIB program and repayment of its 5.38 percent unsecured notes with a principal of US$133 million.

In the nine months ended September 30, 2025, compared with 2024, increases were primarily due to payment for redemption of preferred shares and repayment of long-term debt, partially offset by lower dividends paid due to a variable dividend that was paid in the second quarter of 2024 that did not reoccur in 2025.

Working Capital

Working capital as at September 30, 2025, was $4.1 billion (December 31, 2024 – $3.1 billion). The increase was primarily driven by higher accounts receivable related to proceeds from the divestiture of WRB, partially offset by lower inventories. Proceeds from the divestiture of WRB were received on October 1, 2025.

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. Our Net Debt target is $4.0 billion and 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 a WTI price of approximately US$45.00 per barrel.

Over time, we plan to return 100 percent of Excess Free Funds Flow to shareholders, while stewarding Net Debt near $4.0 billion. Working capital movements, foreign exchange rate changes 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2025**	2024	**2025**	2024
Excess Free Funds Flow [(1)]	**745**	146	**812**	1,713
Target Return [(2)]	**745**	146	**812**	930
Shareholder Returns by way of:				
Purchase of Common Shares Under NCIB	**918**	732	**1,281**	1,337
Variable Dividends Paid	**—**	—	**—**	251
Preferred Share Redemption	**—**	—	**350**	—
Total	**918**	732	**1,631**	1,588

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

(2) The target return for the three and nine months ended September 30, 2025, was 100 percent of Excess Free Funds Flow. The target return for the nine months ended September 30, 2024, includes 100 percent of Excess Free Funds Flow in the third quarter of 2024, and 50 percent of Excess Free Funds Flow in the first and second quarters of 2024.

Short-Term Borrowings

On September 30, 2025, Cenovus completed the divestiture of its entire 50 percent interest in WRB, which included the Company's proportionate share of the WRB uncommitted demand facilities outstanding of US$225 million (C$313 million). Cenovus's proportionate share of the WRB uncommitted demand facilities outstanding as at December 31, 2024, was US$120 million (C$173 million).

Long-Term Debt, Including Current Portion

Long-term debt, including the current portion, as at September 30, 2025, was $7.2 billion (December 31, 2024 – $7.5 billion). We hold U.S. dollar denominated unsecured notes of US$3.7 billion (C$5.1 billion) (December 31, 2024 – US$3.8 billion (C$5.5 billion)) and Canadian dollar denominated unsecured notes of $2.0 billion (December 31, 2024 – $2.0 billion).

Upon maturity on July 15, 2025, the Company repaid its 5.38 percent unsecured notes with a principal of US$133 million, in full.

As at September 30, 2025, we were in compliance with all of the terms of our debt agreements, which includes 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.

Available Sources of Liquidity

The following sources of liquidity are available as at September 30, 2025:

($ millions)	Maturity	Amount Available
Cash and Cash Equivalents	**n/a**	**1,901**
Committed Credit Facility [(1)]		
Revolving Credit Facility – Tranche A	**September 19, 2029**	**3,300**
Revolving Credit Facility – Tranche B	**September 19, 2028**	**2,200**
Uncommitted Demand Facilities [(2)]	**n/a**	**1,094**

(1) No amounts were drawn on the committed credit facility as at September 30, 2025 (December 31, 2024 – $nil).

(2) Represents amounts available for cash draws. Our uncommitted demand facilities include $1.5 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, 2025, there were outstanding letters of credit aggregating to $338 million (December 31, 2024 – $355 million) and no direct borrowings (December 31, 2024 – $nil).

On September 19, 2025, Cenovus renewed its existing committed credit facility to extend the maturity dates by more than one year. As at September 30, 2025, the committed credit facility consists of a $3.3 billion tranche maturing on September 19, 2029, and a $2.2 billion tranche maturing on September 19, 2028. As at September 30, 2025, no amount was drawn on the credit facility (December 31, 2024 – $nil).

MEG Acquisition

On August 21, 2025, Cenovus obtained fully committed financing of a $2.7 billion three-year term loan and a $2.5 billion bridge facility to fund the cash consideration portion of the MEG Acquisition. No amounts were outstanding on the term loan and bridge facility as at September 30, 2025.

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. We plan to renew the base shelf prospectus that 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, 2025**	December 31, 2024
Net Debt to Adjusted EBITDA Ratio (times)	**0.6**	0.5
Net Debt to Adjusted Funds Flow Ratio (times)	**0.7**	0.6
Net Debt to Capitalization Ratio (percent)	**16**	13

Our Net Debt to Adjusted EBITDA ratio and our Net Debt to Adjusted Funds Flow ratio targets are approximately 1.0 times and Net Debt at or below $4.0 billion over the long-term at a WTI price of US$45.00 per barrel. These measures may fluctuate periodically outside this range due to factors such as persistently high or low commodity prices or the strengthening or weakening of the Canadian dollar relative to the U.S. dollar. 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, steward working capital, draw down on our credit facilities or repay existing debt, adjust dividends paid to shareholders, purchase our common or preferred shares for cancellation, issue new debt, or issue new shares.

Our Net Debt to Adjusted EBITDA ratio and Net Debt to Adjusted Funds Flow ratio as at September 30, 2025, increased compared with December 31, 2024, primarily as a result of higher Net Debt. See the Operating and Financial Results section of this MD&A for more information on changes in Net Debt.

Our Net Debt to Capitalization ratio as at September 30, 2025, increased compared with December 31, 2024, primarily due to higher Net Debt.

Share Capital and Stock-Based Compensation Plans

Our common shares and common share purchase warrants ("Cenovus Warrants") are listed on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange. Our cumulative redeemable preferred shares series 1 and 2 are listed on the TSX. On March 31, 2025, and June 30, 2025, Cenovus exercised its right to redeem all 8.0 million of the Company's series 5 preferred shares and 6.0 million of the Company's series 7 preferred shares, respectively. The preferred shares were redeemed at a price of $25.00 per share, for a total of $350 million.

As at September 30, 2025, there were approximately 1,766.3 million common shares outstanding (December 31, 2024 – 1,825.0 million common shares) and 12.0 million preferred shares outstanding (December 31, 2024 – 26.0 million preferred shares).

In the fourth quarter of 2024, Cenovus established an employee benefit plan trust (the "Trust"). The Trust, through an independent trustee, acquires Cenovus's common shares on the open market, which are held to satisfy the Company's obligations under certain stock-based compensation plans. For the nine months ended September 30, 2025, the Trust purchased 4.6 million common shares for a total of $94 million and distributed 3.8 million common shares for a total of $82 million under the employee benefit plan. As at September 30, 2025, there were 2.8 million common shares held by the Trust (December 31, 2024 – 2.0 million common shares). Refer to Note 15 of the interim Consolidated Financial Statements for further details.

As at September 30, 2025, there were approximately 2.9 million Cenovus Warrants outstanding (December 31, 2024 – 3.6 million). 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 15 of the interim Consolidated Financial Statements for further details.

Refer to Note 17 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 27, 2025	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**1,751,241**	**n/a**
Cenovus Warrants	**2,870**	**n/a**
Series 1 First Preferred Shares	**10,740**	**n/a**
Series 2 First Preferred Shares	**1,260**	**n/a**
Stock Options	**11,141**	**5,162**
Other Stock-Based Compensation Plans	**19,570**	**2,006**

Common Share Dividends

In the three months ended September 30, 2025, we declared and paid base dividends of $356 million or $0.200 per common share (2024 – $329 million or $0.180 per common share). In the nine months ended September 30, 2025, we declared and paid base dividends of $1.0 billion or $0.580 per common share (2024 – $925 million or $0.500 per common share).

On October 30, 2025, the Board declared a fourth quarter base dividend of $0.200 per common share. The dividend is payable on December 31, 2025, to common shareholders of record as at December 15, 2025.

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

Cumulative Redeemable Preferred Share Dividends

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2025**	2024	**2025**	2024
Series 1 First Preferred Shares	**2**	2	**5**	5
Series 2 First Preferred Shares	**—**	1	**1**	2
Series 3 First Preferred Shares	**—**	3	**—**	9
Series 5 First Preferred Shares	**—**	2	**2**	7
Series 7 First Preferred Shares	**—**	1	**4**	4
Total Preferred Share Dividends Declared	**2**	9	**12**	27

On October 30, 2025, the Board declared a fourth quarter dividend on the series 1 and 2 preferred shares for a total of $2 million, payable on December 31, 2025, to preferred shareholders of record as at December 15, 2025.

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 127.5 million common shares from November 11, 2024, to November 10, 2025.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2025	2024	**2025**	2024
Common Shares Purchased and Cancelled Under NCIB (millions of common shares)	**40.4**	28.4	**60.5**	51.2
Weighted Average Price per Common Share ($)	**22.31**	25.22	**20.75**	25.60
Purchase of Common Shares Under NCIB ($ millions)	**918**	732	**1,281**	1,337

From October 1, 2025, to October 27, 2025, the Company purchased an additional 17.0 million common shares for $409 million. As at October 27, 2025, the Company can further purchase up to 48.8 million common shares under the NCIB.

On October 30, 2025, 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 120 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 22 of the interim Consolidated Financial Statements.

Our total commitments were $27.2 billion as at September 30, 2025 (December 31, 2024 – $27.3 billion), of which $24.4 billion are for various transportation and storage commitments. Transportation commitments include $1.5 billion that are subject to regulatory approval or were approved but are not yet in service. Terms are up to 15 years on commencement.

As at September 30, 2025, our total commitments included commitments with HMLP of $1.7 billion related to long-term transportation and storage commitments (December 31, 2024 – $1.8 billion).

As at September 30, 2025, outstanding letters of credit issued as security for performance under certain contracts totaled $338 million (December 31, 2024 – $355 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

Husky Midstream Limited Partnership

The Company jointly owns and is the operator of HMLP. The Company holds a 35 percent interest in HMLP and applies the equity method of accounting. The Company charges HMLP for construction and management services, and incurs costs for the use of HMLP's pipeline systems, as well as transportation and storage services.

The following table summarizes revenues and associated expenses related to HMLP:

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2025**	2024	**2025**	2024
Revenues from Construction and Management Services	**50**	47	**116**	116
Transportation Expenses	**66**	67	**203**	207

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 2024 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, 2024.

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, 2024.

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, 2025. 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, 2025.

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 "advance", "aim", "allocate", "anticipate", "believe", "commit", "continue", "could", "deliver", "expect", "F", "focus", "grow", "maintain", "may", "maximize", "mitigate", "on track", "objective", "ongoing", "opportunities", "optimize", "plan", "position", "potential", "priority", "progress", "strategy", "steward", "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 performance; sustainability; our commitment to the Pathways Alliance foundational project; maximizing value and profitability; disciplined capital allocation; cash flow volatility and stability; price alignment and volatility management strategies; dividends; focus on cost and sustainability improvements; liquidity; our 2025 corporate guidance; realizing the full value of our integrated strategy; capitalizing on opportunities; Net Debt target; allocating Excess Free Funds Flow; absolute and per share Free Funds Flow growth; our competitive, reliable downstream business allowing us to be agile in our response to fluctuating demand for refined products and serving as a natural partial hedge in times of widening location and heavy oil differentials; project execution; growing our competitive advantages while operating safely and reliably monitoring market fundamentals and optimizing run rates at our refineries; safe and reliable operations; being best-in-class operators; maintaining a strong balance sheet; costs; margins; long-term value for Cenovus; timing of commissioning and commencement of drilling at the West White Rose project; progressing growth projects, including ramping up production at Narrows Lake, the Foster Creek optimization, Lloydminster drilling program and Sunrise growth projects; our sustainability focus areas and targets; provision for income taxes; funding near-term cash requirements; credit ratings; meeting payment obligations; general outlook for crude oil and refined product prices; price volatility and geopolitical risks; impact of U.S. tariffs on market benchmarks and Cenovus; 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, NGLs, condensate and refined products prices, and light-heavy crude oil price differentials; the Company's ability to realize the anticipated benefits of acquisitions; the accuracy of any assessments undertaken in connection with acquisitions; forecast production and crude throughput volumes and timing thereof; forecast prices and costs, 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, royalty regimes, interest rates, inflation, foreign exchange rates, global economic activity, 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, third party actions, 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 Company's ability to use financial derivatives to manage its exposure to fluctuations in commodity prices, foreign exchange rate and interest rates; 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 and development plans and dividends, including any increase thereto; our downstream business allowing us to be agile in our response to fluctuating demand for refined products and serving as a natural partial hedge in times of widening location and heavy oil differentials;

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 Company's ability to produce from oil sands facilities on an unconstrained basis; estimates of quantities of oil, bitumen, NGLs from properties and other sources not currently classified as proved; the accuracy of accounting estimates and judgments; the Company's ability to obtain necessary regulatory and partner approvals; the successful, timely and cost effective implementation of capital projects, development projects or stages thereof; the Company's ability to meet current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; the Company's ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; the Company's ability to complete acquisitions and 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 sustainability targets and the Pathways Alliance project, the commercial viability and scalability of related technology and products; collaboration with the government, Pathways Alliance and other industry organizations; market and business conditions; forecast inflation and other assumptions inherent in the Company's 2025 guidance available on cenovus.com and as set out below; and other risks and uncertainties described from time to time in the filings the Company makes with securities regulatory authorities.

2025 guidance dated July 30, 2025, and October 30, 2025, and available on cenovus.com, assumes: Brent prices of US$69.00 per barrel, WTI prices of US$65.00 per barrel; WCS of US$53.50 per barrel; Differential WTI-WCS of US$11.50 per barrel; AECO natural gas prices of $2.00 per Mcf; Chicago 3-2-1 crack spread of US$18.50 per barrel; RINs of US$5.50 per barrel; and an exchange rate of $0.72 US$/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; the Company's ability to successfully integrate acquired business with its own in a timely and cost effective manner; 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 sustainability targets and the Pathways Alliance project and the commercial viability and scalability of related technology and products; the effect of new significant shareholders; volatility of and other assumptions regarding commodity prices; the duration of any market downturn; the Company's ability to integrate upstream and downstream operations to help mitigate the impact of volatility in light-heavy crude oil differentials and contribute to its net earnings; 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, the impact of tariffs and responses thereto, currency and interest rates; 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; the ability to complete and optimize drilling, completion, tie in and infrastructure projects; the ability of the Company to ramp-up activities at its refineries on its anticipated timelines; 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; tax audits and reassessments; 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, epidemics and pandemics; and catastrophic events, including, but not limited to, war, adverse sea conditions, extreme weather events, natural disasters, acts of activism, vandalism

and terrorism, and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites and other accidents or similar events; refining and marketing margins; cost escalations, including inflationary pressures on operating costs, such as labour, materials, natural gas and other energy sources used in oil sands processes and downstream operations and increased insurance deductibles or premiums; the cost and availability of equipment necessary to the Company's operations; potential failure of products to achieve or maintain acceptance in the market; risks associated with the energy industry's and the Company's reputation, social license to operate and litigation related thereto; unexpected cost increases or technical difficulties in operating, constructing or modifying 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; OPEC+ policy; 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 for sustainability 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/d	thousand barrels of oil equivalent per day
WCS	Western Canadian Select	MMcf/d	million cubic feet per day	DD&A	depreciation, depletion and amortization
WTI	West Texas Intermediate			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
				USGC	U.S. Gulf Coast

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, Realized Sales Price, Conventional, Offshore and Asia Pacific Per-Unit Operating Expenses, Netbacks (including the total Netback per BOE), Gross Margin, Adjusted Gross Margin, Adjusted Refining Margin and Adjusted Market Capture.

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 section 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 and Excess Free Funds Flow for prior period information from 2025 and 2024 that is not found below.

Non-GAAP Financial 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. The following tables provide a reconciliation to our interim Consolidated Financial Statements.

Operating Margin

	Three Months Ended September 30,					
	2025	2024	**2025**	2024	**2025**	2024
($ millions)	**Upstream** [1]		**Downstream** [1]		**Total**	
Gross Sales						
External Sales [2]	**5,774**	6,052	**8,279**	8,696	**14,053**	14,748
Intersegment Sales	**1,788**	2,207	**156**	102	**1,944**	2,309
	7,562	8,259	**8,435**	8,798	**15,997**	17,057
Royalties	**(858)**	(929)	**—**	—	**(858)**	(929)
Revenues [2]	**6,704**	7,330	**8,435**	8,798	**15,139**	16,128
Expenses						
Purchased Product [2]	**674**	1,088	**7,321**	8,207	**7,995**	9,295
Transportation and Blending	**2,543**	2,661	**—**	—	**2,543**	2,661
Operating	**885**	860	**751**	918	**1,636**	1,778
Realized (Gain) Loss on Risk Management	**12**	(10)	**(1)**	(4)	**11**	(14)
Operating Margin	**2,590**	2,731	**364**	(323)	**2,954**	2,408

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Comparative period reflects certain revisions. See the Prior Period Revisions section of this MD&A for further details.

	Nine Months Ended September 30,					
	2025	2024	**2025**	2024	**2025**	2024
($ millions)	**Upstream [1]**		**Downstream [1]**		**Total**	
Gross Sales						
External Sales [2]	**17,981**	18,590	**23,217**	25,409	**41,198**	43,999
Intersegment Sales	**6,227**	6,248	**666**	372	**6,893**	6,620
	24,208	24,838	**23,883**	25,781	**48,091**	50,619
Royalties	**(2,385)**	(2,535)	**—**	—	**(2,385)**	(2,535)
Revenues [2]	**21,823**	22,303	**23,883**	25,781	**45,706**	48,084
Expenses						
Purchased Product [2]	**2,952**	2,674	**21,281**	22,888	**24,233**	25,562
Transportation and Blending	**8,411**	8,515	**—**	—	**8,411**	8,515
Operating	**2,674**	2,647	**2,552**	2,804	**5,226**	5,451
Realized (Gain) Loss on Risk Management	**11**	16	**(6)**	5	**5**	21
Operating Margin	**7,775**	8,451	**56**	84	**7,831**	8,535

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Comparative period reflects certain revisions. See the Prior Period Revisions section of this MD&A for further details.

Operating Margin by Asset

	Three Months Ended September 30, 2025			Nine Months Ended September 30, 2025		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore [1]**	**Atlantic**	**Asia Pacific**	**Offshore [1]**
Gross Sales	**140**	**245**	**385**	**358**	**813**	**1,171**
Royalties	**(2)**	**(13)**	**(15)**	**(4)**	**(56)**	**(60)**
Revenues	**138**	**232**	**370**	**354**	**757**	**1,111**
Expenses						
Purchased Product	**6**	**—**	**6**	**6**	**—**	**6**
Transportation and Blending	**5**	**—**	**5**	**14**	**—**	**14**
Operating	**75**	**28**	**103**	**187**	**86**	**273**
Operating Margin	**52**	**204**	**256**	**147**	**671**	**818**

	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						
Purchased Product	—	—	—	—	—	—
Transportation and Blending	2	—	2	9	—	9
Operating	58	34	92	225	94	319
Operating Margin	10	242	252	28	769	797

(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, net purchases of common shares under the employee benefit plan, 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,	
($ millions)	**2025**	2024	**2025**	2024
Cash From (Used in) Operating Activities	**2,131**	2,474	**5,820**	7,206
(Add) Deduct:				
Settlement of Decommissioning Liabilities	**(94)**	(74)	**(198)**	(170)
Net Change in Non-Cash Working Capital	**(241)**	588	**(179)**	813
Adjusted Funds Flow	**2,466**	1,960	**6,197**	6,563
Capital Investment	**1,154**	1,346	**3,547**	3,537
Free Funds Flow	**1,312**	614	**2,650**	3,026
Add (Deduct):				
Base Dividends Paid on Common Shares	**(356)**	(329)	**(1,047)**	(925)
Dividends Paid on Preferred Shares	**—**	(9)	**(10)**	(27)
Purchase of Common Shares Under Employee Benefit Plan	**(21)**	—	**(94)**	—
Settlement of Decommissioning Liabilities	**(94)**	(74)	**(198)**	(170)
Principal Repayment of Leases	**(89)**	(74)	**(266)**	(219)
Acquisitions, Net of Cash Acquired	**(7)**	(4)	**(236)**	(19)
Proceeds From Divestitures	**—**	22	**13**	47
Excess Free Funds Flow	**745**	146	**812**	1,713

Gross Margin, Adjusted Gross Margin, Adjusted Refining Margin and Adjusted Market Capture

Gross Margin and Adjusted Gross Margin are non-GAAP financial measures that are used to evaluate the performance of our downstream operations. We define Gross Margin as revenues less purchased product and Adjusted Gross Margin as revenues less purchased product, excluding the impact of inventory holding gains or losses.

Inventory holding gains or losses reflects the difference between the cost of volumes produced at current-period costs, which is an indication of current market conditions, and the cost of volumes produced under the FIFO or weighted average cost basis as required by IFRS Accounting Standards, which generally reflects the market conditions at the time feedstock was purchased. The purchase and sale of inventories creates a timing difference that could be anywhere from several weeks to several months. This measure is an estimate of the impact of current-period costs to FIFO or weighted average cost, and assumes that all opening volumes are sold in the current period. Cenovus uses inventory holding gains or losses to analyze the performance of our assets and increase comparability with refining peers.

Adjusted Refining Margin and Adjusted Market Capture contain non-GAAP financial measures. Adjusted Refining Margin is used to evaluate our downstream operations after adjusting for inventory holding gains or losses. Adjusted Market Capture 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. These measures are useful to consistently measure the performance of our downstream operations.

We define Adjusted Refining Margin as Adjusted Gross Margin divided by total processed inputs and Adjusted Market Capture as Adjusted 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.

We previously disclosed Refining Margin and Market Capture, which did not exclude the effect of inventory holding gains or losses. As of March 31, 2025, we have added Adjusted Gross Margin, and replaced our definitions of Refining Margin and Market Capture to exclude the impact of inventory holding gains or losses. We believe these changes provide more comparability and accuracy when measuring the performance of our downstream operations.

Comparative period information has been provided below for these new metrics.

Canadian Refining

($ millions, except where indicated)	Three Months Ended September 30, 2025 **Lloydminster Upgrader and Lloydminster Refinery Total**	**Other [1]**	**Total Canadian Refining [2]**
Revenues	**1,271**	**82**	**1,353**
Purchased Product	**1,050**	**52**	**1,102**
Gross Margin	**221**	**30**	**251**
Add (Deduct):			
Inventory Holding (Gain) Loss	**8**	**—**	**8**
Adjusted Gross Margin	**229**	**30**	**259**
Total Processed Inputs (Mbbls/d)	**114.8**		
Adjusted Refining Margin ($/bbl)	**21.76**		

(1) Includes ethanol operations and crude-by-rail operations.
(2) Revenues and purchased product are found in Note 1 of the interim Consolidated Financial Statements.

($ millions, except where indicated)	Three Months Ended September 30, 2024 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
Add (Deduct):			
Inventory Holding (Gain) Loss	15	1	16
Adjusted Gross Margin	216	27	243
Total Processed Inputs (Mbbls/d)	106.4		
Adjusted Refining Margin ($/bbl)	22.17		

(1) Includes ethanol operations and crude-by-rail operations.
(2) Revenues and purchased product are found in Note 1 of the interim Consolidated Financial Statements.

($ millions, except where indicated)	Nine Months Ended September 30, 2025 **Lloydminster Upgrader and Lloydminster Refinery Total**	**Other [1]**	**Total Canadian Refining [2]**
Revenues	**3,703**	**220**	**3,923**
Purchased Product	**3,070**	**148**	**3,218**
Gross Margin	**633**	**72**	**705**
Add (Deduct):			
Inventory Holding (Gain) Loss	**(1)**	**—**	**(1)**
Adjusted Gross Margin	**632**	**72**	**704**
Total Processed Inputs (Mbbls/d)	**118.3**		
Adjusted Refining Margin ($/bbl)	**19.56**		

(1) Includes ethanol operations and crude-by-rail operations.
(2) Revenues and purchased product are found in Note 1 of the interim Consolidated Financial Statements.

($ millions, except where indicated)	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
Add (Deduct):			
Inventory Holding (Gain) Loss	(4)	2	(2)
Adjusted Gross Margin	557	73	630
Total Processed Inputs (Mbbls/d)	91.4		
Adjusted Refining Margin ($/bbl)	22.27		

(1) Includes ethanol operations and crude-by-rail operations.
(2) Revenues and purchased product are found in Note 1 of the interim Consolidated Financial Statements.

($ millions, except where indicated)	Three Months Ended December 31, 2024 Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Refining
Revenues	1,207	56	1,263
Purchased Product	1,032	36	1,068
Gross Margin	175	20	195
Add (Deduct):			
Inventory Holding (Gain) Loss	—	—	—
Adjusted Gross Margin	175	20	195
Total Processed Inputs (Mbbls/d)	112.1		
Adjusted Refining Margin ($/bbl)	16.96		

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

($ millions, except where indicated)	Year Ended December 31, 2024 Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Refining
Revenues	5,014	296	5,310
Purchased Product	4,278	205	4,483
Gross Margin	736	91	827
Add (Deduct):			
Inventory Holding (Gain) Loss	(4)	2	(2)
Adjusted Gross Margin	732	93	825
Total Processed Inputs (Mbbls/d)	96.6		
Adjusted Refining Margin ($/bbl)	20.72		

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

U.S. Refining

($ millions, except where indicated)	Three Months Ended September 30, 2025	2024	Nine Months Ended September 30, 2025	2024
Revenues [(1)]	**7,082**	7,218	**19,960**	21,734
Purchased Product [(1)]	**6,219**	6,854	**18,063**	19,473
Gross Margin	**863**	364	**1,897**	2,261
Add (Deduct):				
Inventory Holding (Gain) Loss	**80**	209	**165**	(68)
Adjusted Gross Margin	**943**	573	**2,062**	2,193
Total Processed Inputs (Mbbls/d)	**642.8**	568.0	**606.2**	579.0
Adjusted Refining Margin ($/bbl)	**15.92**	10.97	**12.45**	13.82
Operable Capacity (Mbbls/d)	**612.3**	612.3	**612.3**	612.3
Operable Capacity by Regional Benchmark (percent)				
Chicago 3-2-1 Crack Spread Weighting	**81**	81	**81**	81
Group 3 3-2-1 Crack Spread Weighting	**19**	19	**19**	19
Benchmark Prices and Exchange Rate				
Chicago 3-2-1 Crack Spread (US$/bbl)	**24.24**	18.62	**19.85**	18.27
Group 3 3-2-1 Crack Spread (US$/bbl)	**23.72**	18.95	**21.09**	18.19
RINs (US$/bbl)	**6.33**	3.89	**5.74**	3.65
US$ per C$1 – Average	**0.726**	0.733	**0.715**	0.735
Weighted Average Crack Spread, Net of RINs ($/bbl)	**24.53**	20.18	**20.07**	19.87
Adjusted Market Capture (percent)	**65**	54	**62**	70

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

($ millions, except where indicated)	Three Months Ended December 31, 2024	Twelve Months Ended December 31, 2024
Revenues	6,574	28,308
Purchased Product	6,296	25,769
Gross Margin	278	2,539
Add (Deduct):		
Inventory Holding (Gain) Loss	45	(23)
Adjusted Gross Margin	323	2,516
Total Processed Inputs (Mbbls/d)	588.4	581.4
Adjusted Refining Margin ($/bbl)	5.98	11.83
Operable Capacity (Mbbls/d)	612.3	612.3
Operable Capacity by Regional Benchmark (percent)		
Chicago 3-2-1 Crack Spread Weighting	81	81
Group 3 3-2-1 Crack Spread Weighting	19	19
Benchmark Prices and Exchange Rate		
Chicago 3-2-1 Crack Spread (US$/bbl)	12.12	16.74
Group 3 3-2-1 Crack Spread (US$/bbl)	12.66	16.81
RINs (US$/bbl)	4.02	3.74
US$ per C$1 – Average	0.715	0.730
Weighted Average Crack Spread, Net of RINs ($/bbl)	11.47	17.82
Adjusted Market Capture (percent)	52	67

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. 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.

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. Conventional, Offshore and Asia Pacific Per-Unit Operating Expenses contain non-GAAP measures. As of March 31, 2025, modifications were made to our Conventional Netback to include our 30 percent equity interest in the Duvernay joint venture. These modifications resulted in minor adjustments that are captured in the netback calculation on a prospective basis. Offshore and Asia Pacific operating expenses, as used in the basis of our Netback calculations, reflect our 40 percent equity interest in the HCML joint venture. The Duvernay and HCML joint ventures are accounted for using the equity method in the interim Consolidated Financial Statements.

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

Oil Sands

	Basis of Netback Calculation				
Three Months Ended September 30, 2025 ($ millions)	**Foster Creek**	**Christina Lake**	**Sunrise**	**Lloydminster [1]**	**Total Oil Sands [2]**
Gross Sales	1,507	1,616	396	786	**4,305**
Royalties	(320)	(405)	(17)	(89)	**(831)**
Revenues	1,187	1,211	379	697	**3,474**
Expenses					
Purchased Product	—	—	—	—	**—**
Transportation and Blending	249	165	74	35	**523**
Operating	163	153	87	250	**653**
Netback	775	893	218	412	**2,298**
Realized (Gain) Loss on Risk Management					**10**
Operating Margin					**2,288**

	Basis of Netback Calculation	Adjustments			
Three Months Ended September 30, 2025 ($ millions)	**Total Oil Sands [2]**	**Condensate**	**Third-party Sourced**	**Other [3]**	**Total Oil Sands [4]**
Gross Sales	**4,305**	1,892	429	122	**6,748**
Royalties	**(831)**	—	—	—	**(831)**
Revenues	**3,474**	1,892	429	122	**5,917**
Expenses					
Purchased Product	**—**	—	429	78	**507**
Transportation and Blending	**523**	1,892	—	37	**2,452**
Operating	**653**	—	—	2	**655**
Netback	**2,298**	—	—	5	**2,303**
Realized (Gain) Loss on Risk Management	**10**	—	—	—	**10**
Operating Margin	**2,288**	—	—	5	**2,293**

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

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

(1) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.
(2) Includes bitumen and heavy oil.

Three Months Ended September 30, 2024 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands [1]	**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 bitumen and heavy oil.
(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, 2025 ($ millions)	Basis of Netback Calculation				
	Foster Creek	**Christina Lake**	**Sunrise**	**Lloydminster [1]**	**Total Oil Sands [2]**
Gross Sales	4,499	4,500	1,102	2,485	**12,586**
Royalties	(862)	(1,077)	(53)	(287)	**(2,279)**
Revenues	3,637	3,423	1,049	2,198	**10,307**
Expenses					
Purchased Product	—	—	—	—	**—**
Transportation and Blending	862	414	224	112	**1,612**
Operating	558	510	257	702	**2,027**
Netback	2,217	2,499	568	1,384	**6,668**
Realized (Gain) Loss on Risk Management					**10**
Operating Margin					**6,658**

Nine Months Ended September 30, 2025 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands [2]	**Condensate**	**Third-party Sourced**	**Other [3]**	**Total Oil Sands [4]**
Gross Sales	**12,586**	6,456	1,751	322	**21,115**
Royalties	**(2,279)**	—	—	(2)	**(2,281)**
Revenues	**10,307**	6,456	1,751	320	**18,834**
Expenses					
Purchased Product	**—**	—	1,751	244	**1,995**
Transportation and Blending	**1,612**	6,456	—	70	**8,138**
Operating	**2,027**	—	—	5	**2,032**
Netback	**6,668**	—	—	1	**6,669**
Realized (Gain) Loss on Risk Management	**10**	—	—	—	**10**
Operating Margin	**6,658**	—	—	1	**6,659**

(1) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.
(2) Includes bitumen and heavy oil.
(3) Other includes construction, transportation and blending.
(4) 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 [1]	Total Oil Sands [2]
Gross Sales	4,383	4,782	1,194	2,853	**13,212**
Royalties	(893)	(1,146)	(59)	(296)	**(2,394)**
Revenues	3,490	3,636	1,135	2,557	**10,818**
Expenses					
Purchased Product	—	—	—	—	**—**
Transportation and Blending	656	417	235	141	**1,449**
Operating	519	546	191	619	**1,875**
Netback	2,315	2,673	709	1,797	**7,494**
Realized (Gain) Loss on Risk Management					**23**
Operating Margin					**7,471**

Nine Months Ended September 30, 2024 ($ millions)	Basis of Netback Calculation Total Oil Sands [2]	Adjustments Condensate	Third-party Sourced	Other [3]	Total Oil Sands [4]
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) Includes bitumen and heavy oil.
(3) Other includes construction, transportation and blending.
(4) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Conventional

Three Months Ended September 30, 2025 ($ millions)	Basis of Netback Calculation Conventional [1]	Adjustments Third-party Sourced	Other [1] [2]	Conventional [3]
Gross Sales	**242**	161	26	**429**
Royalties	**(12)**	—	—	**(12)**
Revenues	**230**	161	26	**417**
Expenses				
Purchased Product	**—**	161	—	**161**
Transportation and Blending	**64**	—	22	**86**
Operating	**121**	—	6	**127**
Netback	**45**	—	(2)	**43**
Realized (Gain) Loss on Risk Management	**2**	—	—	**2**
Operating Margin	**43**	—	(2)	**41**

(1) For the three months ended September 30, 2025, reported netbacks are inclusive of revenues and expenses related to the Duvernay joint venture.
(2) Other includes reclassification of costs primarily related to third-party cogeneration, processing and transportation.
(3) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Three Months Ended September 30, 2024 ($ millions)	Basis of Netback Calculation	Adjustments		
	Conventional	**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**

(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, 2025 ($ millions)	Basis of Netback Calculation	Adjustments		
	Conventional [1]	**Third-party Sourced**	**Other [1] [2]**	**Conventional [3]**
Gross Sales	**885**	951	86	**1,922**
Royalties	**(45)**	—	1	**(44)**
Revenues	**840**	951	87	**1,878**
Expenses				
Purchased Product	**—**	951	—	**951**
Transportation and Blending	**183**	—	76	**259**
Operating	**351**	—	18	**369**
Netback	**306**	—	(7)	**299**
Realized (Gain) Loss on Risk Management	**1**	—	—	**1**
Operating Margin	**305**	—	(7)	**298**

(1) For the nine months ended September 30, 2025, reported netbacks are inclusive of revenues and expenses related to the Duvernay joint venture.
(2) Other includes the reclassification of costs primarily related to third-party cogeneration, processing and transportation.
(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	Adjustments		
	Conventional	**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**

(1) Other includes the 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, 2025 ($ millions)	Basis of Netback Calculation					Adjustments		
	Atlantic	**China**	**Indonesia [1]**	**Total Asia Pacific**	**Total Offshore**	**Equity Adjustment [1]**	**Other [2]**	**Total Offshore [3]**
Gross Sales	119	245	85	**330**	**449**	(85)	21	**385**
Royalties	(1)	(13)	(21)	**(34)**	**(35)**	21	(1)	**(15)**
Revenues	118	232	64	**296**	**414**	(64)	20	**370**
Expenses								
Purchased Product	—	—	—	**—**	**—**	—	6	**6**
Transportation and Blending	5	—	—	**—**	**5**	—	—	**5**
Operating	75	26	14	**40**	**115**	(12)	—	**103**
Netback	38	206	50	**256**	**294**	(52)	14	**256**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**294**	(52)	14	**256**

Three Months Ended September 30, 2024 ($ millions)	Basis of Netback Calculation					Adjustments		
	Atlantic	**China**	**Indonesia [1]**	**Total Asia Pacific**	**Total Offshore**	**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**

(1) Revenues and expenses related to the HCML joint venture.
(2) Includes other activities not attributable to the production of crude oil and natural gas.
(3) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Nine Months Ended September 30, 2025 ($ millions)	Basis of Netback Calculation					Adjustments		
	Atlantic	**China**	**Indonesia [1]**	**Total Asia Pacific**	**Total Offshore**	**Equity Adjustment [1]**	**Other [2]**	**Total Offshore [3]**
Gross Sales	337	813	260	**1,073**	**1,410**	(260)	21	**1,171**
Royalties	(3)	(56)	(69)	**(125)**	**(128)**	69	(1)	**(60)**
Revenues	334	757	191	**948**	**1,282**	(191)	20	**1,111**
Expenses								
Purchased Product	—	—	—	**—**	**—**	—	6	**6**
Transportation and Blending	14	—	—	**—**	**14**	—	—	**14**
Operating	184	79	44	**123**	**307**	(37)	3	**273**
Netback	136	678	147	**825**	**961**	(154)	11	**818**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**961**	(154)	11	**818**

(1) Revenues and expenses related to the HCML joint venture.
(2) Includes other activities not attributable to the production of crude oil and natural gas.
(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					Adjustments		
	Atlantic	China	Indonesia [1]	Total Asia Pacific	Total Offshore	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**

(1) Revenues and expenses related to the HCML joint venture.
(2) Includes other activities not attributable to the production of crude oil and natural gas.
(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)	**2025**	2024	**2025**	2024
Oil Sands [2]				
Foster Creek	**206.2**	191.7	**201.5**	190.4
Christina Lake	**251.3**	221.6	**234.4**	227.3
Sunrise	**54.2**	54.4	**51.2**	49.2
Lloydminster	**120.2**	126.6	**124.2**	128.4
Total Oil Sands	**631.9**	594.3	**611.3**	595.3
Conventional [3]	**126.9**	118.1	**123.6**	120.5
Offshore				
Atlantic	**13.6**	7.2	**12.4**	8.6
Asia Pacific				
China	**35.2**	40.5	**38.1**	42.6
Indonesia [4]	**16.7**	16.0	**16.0**	14.8
Total Asia Pacific	**51.9**	56.5	**54.1**	57.4
Total Offshore	**65.5**	63.7	**66.5**	66.0

(1) Sales volumes exclude the impact of purchased condensate.
(2) Includes bitumen and heavy crude oil sales.
(3) For the three and nine months ended September 30, 2025, reported sales volumes reflect Cenovus's 30 percent equity interest in the Duvernay joint venture.
(4) Reported sales volumes reflect Cenovus's 40 percent equity interest in the HCML joint venture.

Other Specified Financial Measures

Per-Unit Operating Expenses

Per-unit operating expenses are specified financial measures used to evaluate the performance of our upstream and downstream operations. 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.

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 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.

PRIOR PERIOD REVISIONS

In December 2024, it was identified that certain transactions in the U.S. Refining segment were reported on a gross basis in revenues and purchased product rather than on a net basis. As a result, revenues and purchased product were overstated for the nine months ended September 30, 2024. The prior periods were revised to reflect the change. There was no impact on net earnings (loss), segment income (loss), cash flows or financial position.

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

	U.S. Refining Segment			Consolidated		
For the three months ended March 31, 2024	Previously Reported	Revisions	Revised Balance	Previously Reported	Revisions	Revised Balance
Revenues	7,235	(334)	**6,901**	13,397	(334)	**13,063**
Purchased Product	6,132	(334)	**5,798**	6,133	(334)	**5,799**
Transportation and Blending	—	—	**—**	2,575	—	**2,575**
Purchased Product, Transportation and Blending	6,132	(334)	**5,798**	8,708	(334)	**8,374**
	1,103	—	**1,103**	4,689	—	**4,689**

	U.S. Refining Segment			Consolidated		
For the three months ended June 30, 2024	Previously Reported	Revisions	Revised Balance	Previously Reported	Revisions	Revised Balance
Revenues	7,918	(303)	**7,615**	14,885	(303)	**14,582**
Purchased Product	7,124	(303)	**6,821**	7,184	(303)	**6,881**
Transportation and Blending	—	—	**—**	2,865	—	**2,865**
Purchased Product, Transportation and Blending	7,124	(303)	**6,821**	10,049	(303)	**9,746**
	794	—	**794**	4,836	—	**4,836**

	U.S. Refining Segment			Consolidated		
For the three months ended September 30, 2024	Previously Reported	Revisions	Revised Balance	Previously Reported	Revisions	Revised Balance
Revenues	7,648	(430)	**7,218**	14,249	(430)	**13,819**
Purchased Product	7,284	(430)	**6,854**	7,556	(430)	**7,126**
Transportation and Blending	—	—	**—**	2,489	—	**2,489**
Purchased Product, Transportation and Blending	7,284	(430)	**6,854**	10,045	(430)	**9,615**
	364	—	**364**	4,204	—	**4,204**

	U.S. Refining Segment			Consolidated		
For the nine months ended September 30, 2024	Previously Reported	Revisions	Revised Balance	Previously Reported	Revisions	Revised Balance
Revenues	22,801	(1,067)	**21,734**	42,531	(1,067)	**41,464**
Purchased Product	20,540	(1,067)	**19,473**	20,873	(1,067)	**19,806**
Transportation and Blending	—	—	**—**	7,929	—	**7,929**
Purchased Product, Transportation and Blending	20,540	(1,067)	**19,473**	28,802	(1,067)	**27,735**
	2,261	—	**2,261**	13,729	—	**13,729**