Cenovus Energy Inc.

Management's Discussion and Analysis (unaudited)

For the Periods Ended June 30, 2024

(Canadian Dollars)

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the periods ended June 30, 2024

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", the "Company", or "Cenovus", and means Cenovus Energy Inc., the subsidiaries of, joint arrangements, and partnership interests held directly or indirectly by, Cenovus Energy Inc.) dated July 31, 2024, should be read in conjunction with our June 30, 2024 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2023 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2023 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as at July 31, 2024, unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus management ("Management") prepared the MD&A. The Audit Committee of the Cenovus Board of Directors ("the Board"), reviewed and recommended the MD&A for approval by the Board, which occurred on July 31, 2024. Additional information about Cenovus, including our quarterly and annual reports, Annual Information Form ("AIF") and Form 40-F, is available on SEDAR+ at sedarplus.ca, on EDGAR at sec.gov, and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, do not constitute part of this MD&A.

Basis of Presentation

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

OVERVIEW OF CENOVUS

We are a Canadian-based integrated energy company headquartered in Calgary, Alberta. We are one of the largest Canadian-based crude oil and natural gas producers, with upstream operations in Canada and the Asia Pacific region, and one of the largest Canadian-based refiners and upgraders, with downstream operations in Canada and the United States ("U.S.").

Our upstream operations include oil sands projects in northern Alberta; thermal and conventional crude oil, natural gas and natural gas liquids ("NGLs") projects across Western Canada; crude oil production offshore Newfoundland and Labrador; and natural gas and NGLs production offshore China and Indonesia. Our downstream operations include upgrading and refining operations in Canada and the U.S., and commercial fuel operations across Canada.

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

Our Strategy

At Cenovus, our purpose is to energize the world to make people's lives better. Our strategy is focused on maximizing shareholder value over the long-term through sustainable, low-cost, diversified and integrated energy leadership. Our five strategic objectives include: delivering top tier safety performance; maximizing value through competitive cost structures and optimizing margins; a focus on financial discipline, including reaching and maintaining targeted debt levels while positioning Cenovus for resiliency through commodity price cycles; a disciplined approach to allocating capital to projects that generate returns at the bottom of the commodity price cycle; and the prioritization of Free Funds Flow generation through all price cycles to manage our balance sheet, increase shareholder returns through dividend growth and common share purchases, reinvest in our business, and diversify our portfolio.

On December 14, 2023, we released our 2024 budget focused on disciplined capital investment and balancing growth of our base business with meaningful shareholder returns. We will remain focused on safe operations, reducing costs, capital discipline and realizing the full value of our integrated business. Our 2024 corporate guidance was updated on July 31, 2024, and is available on our website at cenovus.com. For further details, see the Outlook section of this MD&A.

Our Operations

The Company operates through the following reportable segments:

Upstream Segments

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

Downstream Segments

- **Canadian Refining,** includes the owned and operated Lloydminster upgrading and asphalt refining complex, which converts heavy oil and bitumen into synthetic crude oil, diesel, asphalt and other ancillary products. Cenovus also owns and operates the Bruderheim crude-by-rail terminal and two ethanol plants. The Company's commercial fuels business across Canada is included in this segment. Cenovus markets its production and third-party commodity trading volumes in an effort to use its integrated network of assets to maximize value.

- **U.S. Refining,** includes the refining of crude oil to produce gasoline, diesel, jet fuel, asphalt and other products at the wholly-owned Lima, Superior and Toledo refineries, and the jointly-owned Wood River and Borger refineries, held through WRB Refining LP ("WRB"), a jointly owned entity with operator Phillips 66. Cenovus markets some of its own and third-party refined products including gasoline, diesel, jet fuel and asphalt.

Corporate and Eliminations

Corporate and Eliminations, includes Cenovus-wide costs for general and administrative, financing activities, gains and losses on risk management for corporate related derivative instruments and foreign exchange. Eliminations include adjustments for feedstock and internal usage of crude oil, natural gas, condensate, other NGLs and refined products between segments; transloading services provided to the Oil Sands segment by the Company's crude-by-rail terminal; the sale of condensate extracted from blended crude oil production in the Canadian Refining segment and sold to the Oil Sands segment; and unrealized profits in inventory. Eliminations are recorded based on market prices.

QUARTERLY RESULTS OVERVIEW

The second quarter's financial and operational results reflect strong operational performance and constructive crude oil prices at our Oil Sands assets, the impact that the execution of the turnaround at the Lloydminster Upgrader (the "Upgrader") had on our Canadian Refining segment, and increased crude oil unit throughput ("throughput") at our U.S. Refineries, offset by the impact of the narrowing WTI-WCS differential at Hardisty and volatile market crack spreads.

- **Continued focus on safety.** We maintained safe operations throughout our business, and are continually striving to improve our safety record. Safety continues to be a key priority for 2024.
- **Achieved our Net Debt target in July.** As at June 30, 2024, our Net Debt position was $4.3 billion and in July, we reached our Net Debt target of $4.0 billion. As such, in the third quarter of 2024, we will target to allocate 100 percent of Excess Free Funds Flow to shareholder returns, adjusted for the amount Net Debt exceeded $4.0 billion, which was $258 million at June 30, 2024.
- **Strong upstream production.** Upstream production averaged 800.8 thousand barrels of oil equivalent per day in the second quarter, consistent with 800.9 thousand barrels of oil equivalent per day in the first quarter of 2024.
- **Safely executed the Lloydminster Upgrader turnaround.** From May 8 to July 4, 2024, we completed the largest turnaround in the history of the Upgrader. As a result, throughput in the Canadian Refining segment decreased 50.3 thousand barrels per day from the first quarter of 2024 to 53.8 thousand barrels per day. Total Canadian Refining operating expenses of $415 million included $211 million related to the turnaround. The Upgrader has returned to full operations.
- **Improved U.S. Refining throughput.** Crude throughput at our U.S. refineries was 568.9 thousand barrels per day in the quarter, an increase of 17.8 thousand barrels per day from the first quarter of 2024, due to improved crude unit reliability at our operated and non-operated refineries.
- **Drove improvements to our cost structures.** Per-Unit Operating Expenses at our Oil Sands and Conventional assets decreased from the first quarter of 2024. We continue to focus on reducing operating, capital and general and administrative costs.
- **Progressed key Atlantic projects.** The West White Rose project reached a significant milestone with the completion of major construction on two key components of the platform. The concrete gravity structure reached its final height and the last crane was installed, completing the topsides structurally. The SeaRose asset life extension ("ALE") project continues to progress the refit work that commenced in the first quarter of 2024. The floating production, storage and offloading unit ("FPSO") is expected to return to the White Rose field late in the third quarter of 2024, with production resuming in the fourth quarter.
- **Advanced our Oil Sands growth projects.** The Narrows Lake tie-back pipeline to Christina Lake is approximately 88 percent constructed and is expected to achieve mechanical completion by the end of the year. At our Sunrise asset, we began steaming two well pads, which we expect to be brought on production in the third and fourth quarters of 2024. Our Foster Creek optimization project is approximately 26 percent complete and is expected to be operational in 2026. At our Lloydminster conventional heavy oil assets, we have progressed our planned drilling program and currently have four rigs in operation.
- **Loaded our first vessels at the Westridge Marine Terminal.** With the successful start-up of the Trans Mountain Pipeline expansion project ("TMX"), we loaded our first vessels at the Westridge Marine Terminal and continue to ramp up our position.

- **Reported solid financial results.** Adjusted funds flow increased to $2.4 billion from $2.2 billion in the first quarter of 2024, mainly due to improved benchmark prices and strong operating results. Cash flow from operating activities was $2.8 billion, an increase from $1.9 billion in the first quarter of 2024, as lower Operating Margin in the second quarter was more than offset by changes in non-cash working capital. Net earnings were $1.0 billion, a decrease of $176 million from the first quarter of 2024.
- **Delivered significant cash returns to common shareholders.** We returned $1.0 billion to common shareholders, composed of the purchase of 15.4 million common shares for $440 million through our normal course issuer bid ("NCIB"), $334 million through common share base dividends and $251 million through common share variable dividends. On July 31, 2024, our Board of Directors declared a third quarter base dividend of $0.180 per common share.

Summary of Quarterly Results

	Six Months Ended June 30,		2024		2023				2022	
($ millions, except where indicated)	**2024**	2023	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Upstream Production Volumes [1] (MBOE/d)	**800.9**	754.4	**800.8**	800.9	808.6	797.0	729.9	779.0	806.9	777.9
Downstream Total Processed Inputs [2] [3] (Mbbls/d)	**668.3**	524.1	**652.9**	683.8	605.7	691.3	566.9	480.7	491.3	563.4
Crude Oil Unit Throughput [2] (Mbbls/d)	**639.0**	498.1	**622.7**	655.2	579.1	664.3	537.8	457.9	473.3	533.5
Downstream Production Volumes [1] [2] (Mbbls/d)	**680.8**	530.0	**659.5**	702.1	627.4	706.0	571.9	487.7	506.3	572.6
Revenues	**28,282**	24,493	**14,885**	13,397	13,134	14,577	12,231	12,262	14,063	17,471
Operating Margin [4]	**6,127**	4,502	**2,936**	3,191	2,151	4,369	2,400	2,102	2,782	3,339
Cash From (Used In) Operating Activities	**4,732**	1,704	**2,807**	1,925	2,946	2,738	1,990	(286)	2,970	4,089
Adjusted Funds Flow [4]	**4,603**	3,294	**2,361**	2,242	2,062	3,447	1,899	1,395	2,346	2,951
Per Share - Basic [4] ($)	**2.47**	1.73	**1.27**	1.20	1.10	1.82	1.00	0.73	1.22	1.53
Per Share - Diluted [4] ($)	**2.45**	1.69	**1.26**	1.19	1.09	1.81	0.98	0.71	1.19	1.49
Capital Investment	**2,191**	2,103	**1,155**	1,036	1,170	1,025	1,002	1,101	1,274	866
Free Funds Flow [4]	**2,412**	1,191	**1,206**	1,206	892	2,422	897	294	1,072	2,085
Excess Free Funds Flow [4]	**n/a**	n/a	**735**	832	471	1,989	505	(499)	786	1,756
Net Earnings (Loss)	**2,176**	1,502	**1,000**	1,176	743	1,864	866	636	784	1,609
Per Share - Basic ($)	**1.16**	0.78	**0.53**	0.62	0.39	0.98	0.45	0.33	0.40	0.83
Per Share - Diluted ($)	**1.15**	0.76	**0.53**	0.62	0.39	0.97	0.44	0.32	0.39	0.81
Total Assets	**56,000**	53,747	**56,000**	54,994	53,915	54,427	53,747	54,000	55,869	55,086
Total Long-Term Liabilities	**18,945**	19,831	**18,945**	18,884	18,993	18,395	19,831	19,917	20,259	19,378
Long-Term Debt, Including Current Portion	**7,275**	8,534	**7,275**	7,227	7,108	7,224	8,534	8,681	8,691	8,774
Net Debt	**4,258**	6,367	**4,258**	4,827	5,060	5,976	6,367	6,632	4,282	5,280
Cash Returns to Common Shareholders	**1,452**	815	**1,025**	427	722	1,225	575	240	807	864
Common Shares – Base Dividends	**596**	465	**334**	262	261	264	265	200	201	205
Base Dividends Per Common Share ($)	**0.320**	0.245	**0.180**	0.140	0.140	0.140	0.140	0.105	0.105	0.105
Common Shares – Variable Dividends	**251**	—	**251**	—	—	—	—	—	219	—
Variable Dividends Per Common Share ($)	**0.135**	—	**0.135**	—	—	—	—	—	0.114	—
Purchase of Common Shares Under NCIB	**605**	350	**440**	165	350	361	310	40	387	659
Payment for Purchase of Warrants	**—**	—	**—**	—	111	600	—	—	—	—
Preferred Share Dividends	**18**	27	**9**	9	9	—	9	18	—	9

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

OPERATING AND FINANCIAL RESULTS

Selected Operating and Financial Results — Upstream

	Three Months Ended June 30,			Six Months Ended June 30,		
	2024	Percent Change	2023	2024	Percent Change	2023
Production Volumes by Segment [1] (MBOE/d)						
Oil Sands	**611.5**	**7**	573.8	**613.4**	**5**	581.6
Conventional	**123.1**	**18**	104.6	**121.9**	**7**	114.2
Offshore	**66.2**	**29**	51.5	**65.6**	**12**	58.6
Total Production Volumes	**800.8**	**10**	729.9	**800.9**	**6**	754.4
Production Volumes by Product						
Bitumen (Mbbls/d)	**591.7**	**7**	554.6	**593.5**	**6**	562.5
Heavy Crude Oil (Mbbls/d)	**18.1**	**6**	17.0	**18.0**	**7**	16.9
Light Crude Oil (Mbbls/d)	**13.5**	**34**	10.1	**13.0**	**2**	12.7
NGLs (Mbbls/d)	**33.0**	**24**	26.7	**32.8**	**9**	30.0
Conventional Natural Gas (MMcf/d)	**867.2**	**19**	729.4	**861.5**	**9**	793.1
Total Production Volumes (MBOE/d)	**800.8**	**10**	729.9	**800.9**	**6**	754.4
Per-Unit Operating Expenses by Segment [2] ($/BOE)						
Oil Sands	**11.47**	**(10)**	12.72	**11.67**	**(13)**	13.37
Conventional	**11.25**	**(23)**	14.59	**12.14**	**(12)**	13.77
Offshore [3]	**22.34**	**15**	19.48	**20.03**	**6**	18.88

(1) Refer to the Oil Sands, Conventional or Offshore Reportable Segments section of this MD&A for a summary of production by product type by segment.
(2) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(3) Reflects Cenovus's 40 percent interest in HCML. Expenses related to the HCML joint venture are accounted for using the equity method in the interim Consolidated Financial Statements.

Total upstream production increased compared with 2023 due to:

- Three new well pads brought online throughout 2023 and one in the first quarter of 2024 at Foster Creek.
- Successful results from the 2023 redevelopment programs, new wells brought online during the year and base well optimizations at our Lloydminster thermal assets.
- The successful restart of operations in the Conventional segment following the temporary shut-in of a significant portion of production in response to wildfire activity in the second quarter of 2023.
- The temporary unplanned outage in China related to the disconnection of the umbilical by a third-party vessel in April 2023.
- Turnarounds that were completed at our Foster Creek and Atlantic operations in the second quarter of 2023.
- The completion of maintenance activity at the Terra Nova FPSO and returning to the field in August 2023. Production resumed in late November 2023.

The increases were partially offset by:

- The suspended production on the SeaRose FPSO for the planned ALE project in late December 2023. The FPSO is expected to return to the White Rose field late in the third quarter of 2024, with production resuming in the fourth quarter.

Per-Unit Operating Expenses decreased in the Oil Sands segment reflecting the benefit of lower fuel operating costs as a result of significant declines in AECO benchmark prices, as well as efforts made to manage operating expenses by securing long-term contracts, working with vendors and purchasing long-lead items to mitigate future cost escalations. Per-Unit Operating Expenses decreased in our Conventional segment primarily due to the divestiture of assets.

Selected Operating and Financial Results — Downstream

	Three Months Ended June 30,			Six Months Ended June 30,		
	2024	**Percent Change**	2023	**2024**	**Percent Change**	2023
Crude Oil Unit Throughput by Segment (Mbbls/d)						
Canadian Refining	**53.8**	**(44)**	95.3	**79.0**	**(19)**	97.0
U.S. Refining	**568.9**	**29**	442.5	**560.0**	**40**	401.1
Total Crude Oil Unit Throughput	**622.7**	**16**	537.8	**639.0**	**28**	498.1
Production Volumes by Product [1] (Mbbls/d)						
Gasoline	**278.3**	**40**	199.4	**280.1**	**45**	193.2
Distillates [2]	**221.5**	**28**	173.3	**217.2**	**34**	162.0
Synthetic Crude Oil	**20.7**	**(54)**	44.8	**33.9**	**(25)**	45.2
Asphalt	**40.2**	**7**	37.4	**41.0**	**28**	32.0
Ethanol	**4.4**	**13**	3.9	**4.9**	**9**	4.5
Other	**94.4**	**(17)**	113.1	**103.7**	**11**	93.1
Total Production Volumes	**659.5**	**15**	571.9	**680.8**	**28**	530.0
Per-Unit Operating Expenses by Segment [3] ($/bbl)						
Canadian Refining [4]	**70.44**	**401**	14.05	**34.36**	**153**	13.59
U.S. Refining	**12.66**	**(21)**	16.09	**12.17**	**(28)**	16.86

(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. The definition of Per-Unit Operating Expense has been revised to operating expenses divided by total processed inputs. Prior periods have been re-presented. See the Specified Financial Measures Advisory of this MD&A.
(4) Represents operating expenses associated with the Lloydminster Upgrader, the Lloydminster Refinery and the commercial fuels business.

Total downstream throughput and total downstream production increased compared with 2023 due to:

- Increased throughput in the U.S. Refining segment as we realized the benefit from the purchase of the Toledo Refinery on February 28, 2023 (the "Toledo Acquisition"), which has allowed us to better use existing resources across our U.S. portfolio to improve our product mix.
- Obtaining the benefit of a full period of throughput and production at the Toledo and Superior refineries.
- Improved crude unit reliability at our operated and non-operated refineries.

The increases were partially offset by:

- The turnaround completed at the Upgrader, which significantly impacted throughput in our Canadian Refining segment.
- Planned and unplanned outages at our operated and non-operated refineries.

Canadian Refining Per-Unit Operating Expenses increased compared with 2023, primarily due to increased turnaround costs at the Upgrader and lower total processed inputs.

U.S. Refining Per-Unit Operating Expenses decreased compared with 2023, primarily due to increased total processed inputs at the Toledo and Superior refineries discussed above and total operating expenses remaining relatively consistent.

Selected Consolidated Financial Results

Revenues

Revenues increased 22 percent to $14.9 billion in the three months ended June 30, 2024, compared with 2023. Year-to-date, revenues increased 15 percent to $28.3 billion, compared with 2023. The increases for both periods were primarily due to increased total upstream production and higher crude oil benchmark pricing, combined with increased total downstream production due to obtaining the benefit of a full period of production at the Toledo and Superior refineries, offset by decreased production in the Canadian Refining segment. The increase was partially offset by lower natural gas and refined product pricing in the three and six months ended June 30, 2024, compared with the same periods in 2023.

Operating Margin

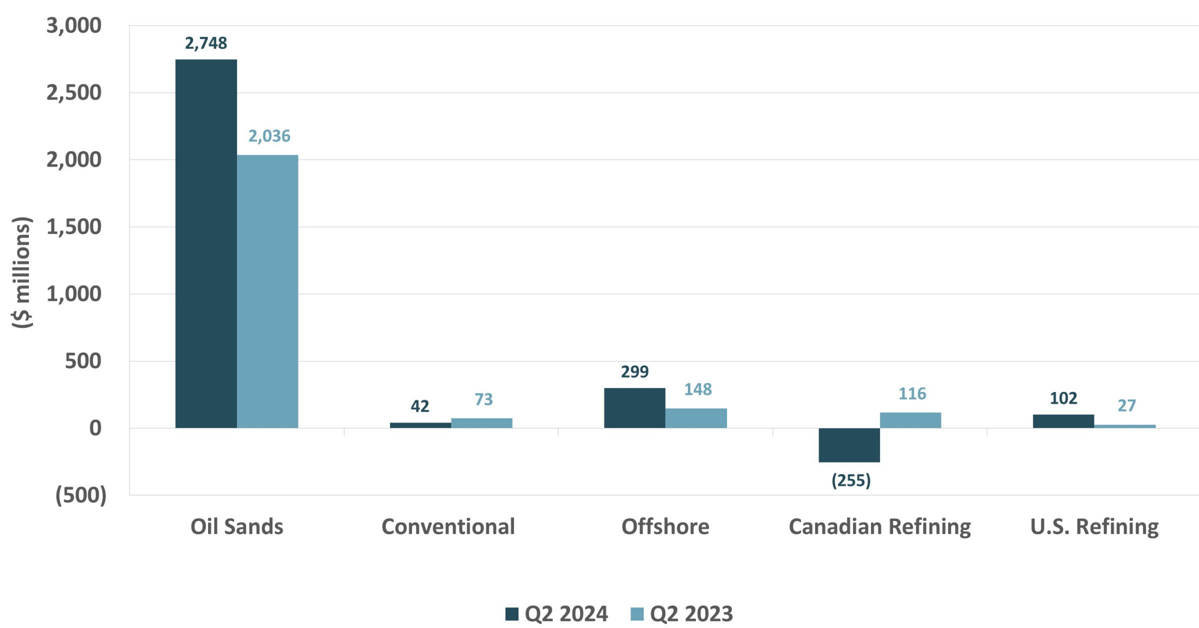
Operating Margin is a non-GAAP financial measure and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods.

($ millions)	Three Months Ended June 30, 2024	2023	Six Months Ended June 30, 2024	2023
Gross Sales [1]				
External Sales	**15,744**	12,868	**29,888**	25,726
Intersegment Sales	**2,024**	1,844	**4,311**	3,340
	17,768	14,712	**34,199**	29,066
Royalties	**(859)**	(637)	**(1,606)**	(1,233)
Revenues	**16,909**	14,075	**32,593**	27,833
Expenses				
Purchased Product [1]	**8,914**	7,198	**16,904**	14,027
Transportation and Blending [1]	**3,043**	2,770	**5,854**	5,797
Operating Expenses	**1,988**	1,726	**3,673**	3,509
Realized (Gain) Loss on Risk Management Activities	**28**	(19)	**35**	(2)
Operating Margin	**2,936**	2,400	**6,127**	4,502

(1) *Comparative periods reflect certain revisions. See Note 24 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.*

Operating Margin by Segment

Three Months Ended June 30, 2024 and 2023



Operating Margin increased $536 million to $2.9 billion in the three months ended June 30, 2024, compared with 2023, primarily due to:

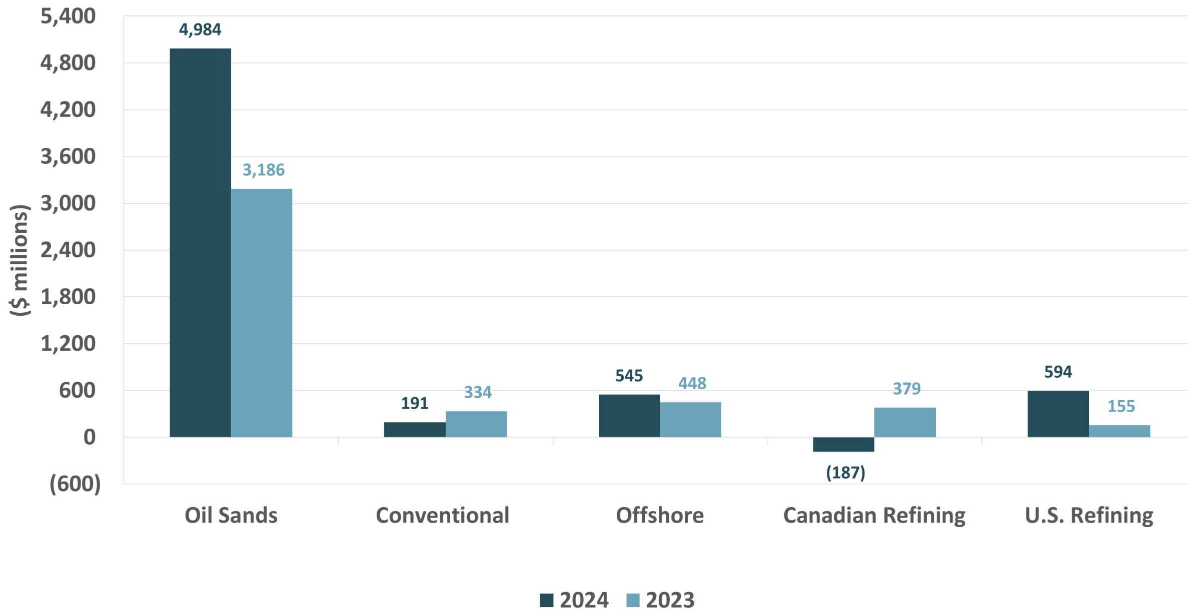
- Higher crude oil benchmark pricing and higher sales volumes impacting our Oil Sands segment.
- Increased sales volumes and higher realized sales prices from our Offshore segment.
- Obtaining the benefit of a full period of production at the Toledo and Superior refineries.

These increases were partially offset by:

- Lower Operating Margin in the Canadian Refining segment due to turnaround activity.
- Increased royalties in our Oil Sands segment due to higher realized prices combined with higher Alberta sliding scale oil sands royalty rates.
- Lower market crack spreads and narrower light-heavy differentials impacting our U.S. Refining segment.
- Increased transportation expenses as we ramp up our use of TMX.

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

Six Months Ended June 30, 2024 and 2023



Operating Margin increased $1.6 billion to $6.1 billion in the six months ended June 30, 2024, compared with 2023, primarily due to the reasons discussed above.

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 June 30,		Six Months Ended June 30,	
($ millions)	**2024**	2023	**2024**	2023
Cash From (Used in) Operating Activities	**2,807**	1,990	**4,732**	1,704
(Add) Deduct:				
Settlement of Decommissioning Liabilities	**(48)**	(41)	**(96)**	(89)
Net Change in Non-Cash Working Capital	**494**	132	**225**	(1,501)
Adjusted Funds Flow	**2,361**	1,899	**4,603**	3,294

Cash from operating activities increased in the second quarter of 2024, compared with the same period in 2023. The increase was primarily due to higher Operating Margin combined with changes in non-cash working capital. Changes in non-cash working capital increased cash from operating activities by $494 million in the quarter, primarily due to higher accounts payable, partially offset by higher inventory.

Cash from operating activities was $4.7 billion in the first six months of 2024, compared with $1.7 billion in 2023. The increase was primarily due to changes in non-cash working capital and higher Operating Margin. In the first half of 2023, changes in non-cash working capital decreased cash from operating activities by $1.5 billion, primarily driven by an income tax payment of $1.2 billion that occurred during the period.

Adjusted Funds Flow was higher in the three and six months ended June 30, 2024, compared with the same periods in 2023. The quarter-over-quarter increase was primarily due to higher Operating Margin, as discussed above, partially offset by higher current income tax expense. The year-over-year increase was primarily due to higher Operating Margin, partially offset by higher current income tax expense and long-term incentive costs paid.

Net Earnings (Loss)

Net earnings in the three and six months ended June 30, 2024, was $1.0 billion and $2.2 billion, respectively, compared with $866 million and $1.5 billion, respectively, in 2023. The increase for both periods was due to higher Operating Margin, as discussed above, partially offset by higher income tax expense, increased DD&A and foreign exchange losses in 2024 compared with gains in 2023.

Net Debt

As at ($ millions)	**June 30, 2024**	December 31, 2023
Short-Term Borrowings	**137**	179
Long-Term Portion of Long-Term Debt	**7,275**	7,108
Total Debt	**7,412**	7,287
Cash and Cash Equivalents	**(3,154)**	(2,227)
Net Debt	**4,258**	5,060

Net Debt decreased by $802 million from December 31, 2023, mainly due to cash from operating activities of $4.7 billion, partially offset by capital investment of $2.2 billion, cash returns to common shareholders of $1.5 billion and the weakening of the Canadian dollar, which impacted our U.S. denominated debt. For further details, see the Liquidity and Capital Resources section of this MD&A.

Capital Investment [1]

	Three Months Ended June 30,		**Six Months Ended June 30,**	
($ millions)	**2024**	2023	**2024**	2023
Upstream				
Oil Sands	**613**	539	**1,260**	1,174
Conventional	**68**	82	**194**	223
Offshore	**295**	184	**454**	284
Total Upstream	**976**	805	**1,908**	1,681
Downstream				
Canadian Refining	**70**	34	**101**	61
U.S. Refining	**100**	153	**167**	347
Total Downstream	**170**	187	**268**	408
Corporate and Eliminations	**9**	10	**15**	14
Total Capital Investment	**1,155**	1,002	**2,191**	2,103

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

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

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

Drilling Activity

Six Months Ended June 30,	Net Stratigraphic Test Wells and Observation Wells 2024	2023	Net Production Wells [1] 2024	2023
Foster Creek	**82**	87	**7**	10
Christina Lake	**58**	53	**9**	11
Sunrise	**40**	38	**—**	7
Lloydminster Thermal	**—**	1	**4**	—
Lloydminster Conventional Heavy Oil	**—**	1	**3**	5
Other	**—**	3	**—**	—
	180	183	**23**	33

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

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

	Six Months Ended June 30, 2024			Six Months Ended June 30, 2023		
(net wells)	**Drilled**	**Completed**	**Tied-in**	Drilled	Completed	Tied-in
Conventional	**18**	**14**	**14**	17	21	22

In the Offshore segment, we commenced drilling one well in China in the second quarter of 2024. No wells were completed in the Offshore segment in the first six months of 2024 (2023 – drilled and completed one (0.4 net) development well at the MAC field in Indonesia).

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates [1]

	Six Months Ended June 30,					
(Average US$/bbl, unless otherwise indicated)	**2024**	**Percent Change**	2023	**Q2 2024**	Q1 2024	Q2 2023
Dated Brent	**84.09**	**5**	79.83	**84.94**	83.24	78.39
WTI	**78.77**	**5**	74.96	**80.57**	76.96	73.78
Differential Dated Brent - WTI	**5.32**	**9**	4.87	**4.37**	6.28	4.61
WCS at Hardisty	**62.30**	**13**	55.05	**66.96**	57.65	58.74
Differential WTI - WCS at Hardisty	**16.47**	**(17)**	19.91	**13.61**	19.31	15.04
WCS at Hardisty (C$/bbl)	**84.70**	**14**	74.17	**91.63**	77.77	78.90
WCS at Nederland	**72.29**	**12**	64.73	**74.69**	69.89	66.98
Differential WTI - WCS at Nederland	**6.48**	**(37)**	10.23	**5.88**	7.07	6.80
Condensate (C5 at Edmonton)	**74.96**	**(2)**	76.13	**77.14**	72.78	72.39
Differential Condensate - WTI Premium/(Discount)	**(3.81)**	**(426)**	1.17	**(3.43)**	(4.18)	(1.39)
Differential Condensate - WCS at Hardisty Premium/(Discount)	**12.66**	**(40)**	21.08	**10.18**	15.13	13.65
Condensate (C$/bbl)	**101.87**	**(1)**	102.61	**105.55**	98.18	97.25
Synthetic at Edmonton	**76.37**	**(1)**	77.42	**83.32**	69.42	76.66
Differential Synthetic - WTI Premium/(Discount)	**(2.40)**	**(198)**	2.46	**2.75**	(7.54)	2.88
Synthetic at Edmonton (C$/bbl)	**103.83**	**—**	104.33	**114.01**	93.65	102.98

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

Selected Benchmark Prices and Exchange Rates – Continued [1]

(Average US$/bbl, unless otherwise indicated)	Six Months Ended June 30, 2024	Percent Change	2023	Q2 2024	Q1 2024	Q2 2023
Refined Product Prices						
Chicago Regular Unleaded Gasoline (“RUL”)	**94.28**	**(7)**	101.07	**99.09**	89.48	102.32
Chicago Ultra-low Sulphur Diesel (“ULSD”)	**102.04**	**(6)**	108.90	**99.80**	104.27	102.40
Refining Benchmarks						
Upgrading Differential [2] (C$/bbl)	**18.97**	**(36)**	29.68	**22.28**	15.65	23.59
Chicago 3-2-1 Crack Spread [3]	**18.10**	**(37)**	28.72	**18.76**	17.45	28.57
Group 3 3-2-1 Crack Spread [3]	**17.82**	**(44)**	31.56	**18.13**	17.50	31.78
Renewable Identification Numbers (“RINs”)	**3.53**	**(56)**	7.98	**3.39**	3.68	7.72
Natural Gas Prices						
AECO [4] (C$/Mcf)	**1.84**	**(35)**	2.83	**1.18**	2.50	2.45
NYMEX [5] (US$/Mcf)	**2.07**	**(25)**	2.76	**1.89**	2.24	2.10
Foreign Exchange Rates						
US$ per C$1 - Average	**0.736**	**(1)**	0.742	**0.731**	0.741	0.745
US$ per C$1 - End of Period	**0.731**	**(3)**	0.755	**0.731**	0.738	0.755
RMB per C$1 - Average	**5.311**	**3**	5.143	**5.293**	5.330	5.228

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

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

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

(4) Alberta Energy Company ("AECO") 5A natural gas daily index.

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

Crude Oil and Condensate Benchmarks

In the second quarter of 2024, crude oil benchmark prices, Brent and WTI, continued to increase compared with the first quarter of 2024. OPEC+ continues to manage global oil markets and support prices with extended production cuts amid robust global demand growth for crude. Geopolitical events related to Russia and Ukraine, Israel and Gaza, Iran, the Red Sea, Venezuela and Guyana continued to add volatility in the second quarter of 2024, but have had a limited impact on global oil markets. Slowing U.S. drilling activity since the beginning of 2023 has further eased some pressure on global crude supply and demand balances.

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

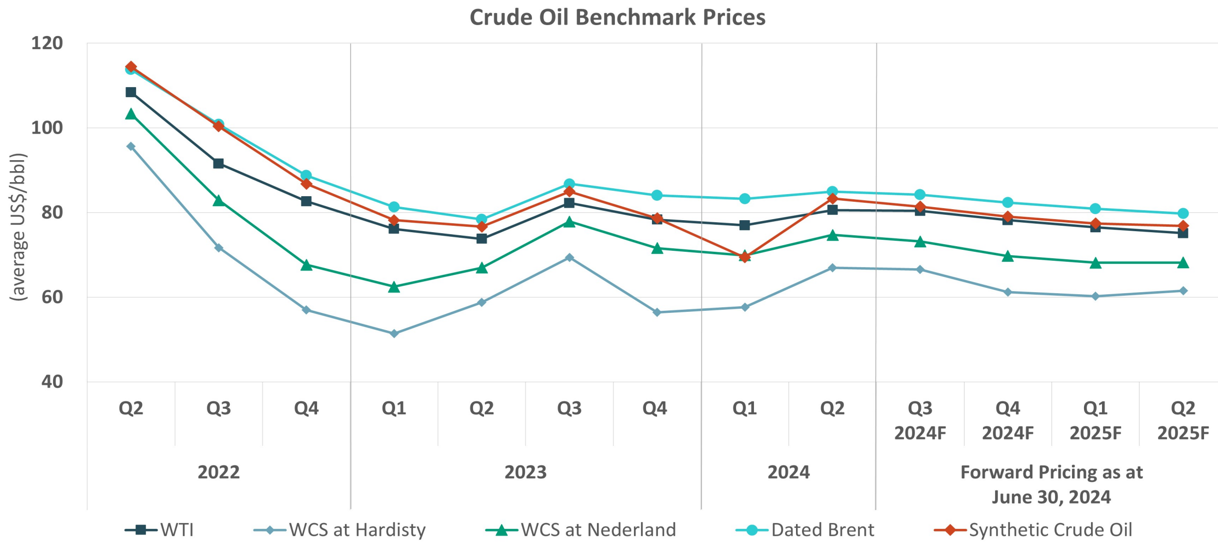
The price received for our Atlantic crude oil and Asia Pacific NGLs is primarily driven by the price of Brent. The Brent-WTI differential narrowed in the second quarter of 2024 compared with the first quarter of 2024, in part due to weaker European light crude demand related to refinery turnarounds.

WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WCS at Hardisty differential to WTI is a function of the quality differential of light and heavy crude, and the cost of transport. In the three and six months ended June 30, 2024, the WTI-WCS differential at Hardisty narrowed compared with 2023, due in part to the start-up of TMX as well as a strengthening of the heavy oil quality differential as outlined below.

WCS at Nederland is a heavy oil benchmark for sales of our product at the U.S. Gulf Coast (“USGC”). The WTI-WCS at Nederland differential is representative of the heavy oil quality differential and is influenced by global heavy oil refining capacity and global heavy oil supply. In the three and six months ended June 30, 2024, the WTI-WCS at Nederland differential narrowed compared with the same periods in 2023. Decreased global heavy and medium crude supply as a result of OPEC+ cuts and additional heavy crude processing capacity have resulted in a narrowing of the quality differential compared with 2023, which experienced wide light-heavy differentials due to unplanned refinery maintenance, high global refining utilization, rising supply of medium and heavy oil barrels into the market and volatile refined product pricing.

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 second quarters of 2024 and 2023, synthetic crude oil at Edmonton was priced at a premium to WTI. Year-to-date, synthetic crude oil at Edmonton was priced at a discount to WTI. The weakness in pricing in the first quarter of 2024 was a result of high synthetic crude oil production in Alberta, an oversupply of light crude which resulted in light crude being above pipeline capacity on light crude pipelines and limited local storage capacity.



Blending condensate with bitumen enables our production to be transported through pipelines. Our blending ratios, calculated as diluent volumes as a percentage of total blended volumes, range from approximately 25 percent to 35 percent. The WCS-Condensate differential is an important benchmark, as a wider differential generally results in a decrease in the recovery of condensate costs when selling a barrel of blended crude oil. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by USGC condensate prices plus the cost to transport the condensate to Edmonton. Our blending costs are also impacted by the timing of purchases and deliveries of condensate into inventory to be available for use in blending, as well as timing of blended product sales.

In the second quarters of 2024 and 2023, the average Edmonton condensate benchmark traded at a discount to WTI. In the six months ended June 30, 2024, Edmonton condensate benchmark traded at a discount compared with a premium in the six months ended June 30, 2023. Weakness was primarily driven by low light crude and synthetic crude oil prices in the first quarter of 2024 in Alberta as oversupply of light crude was above pipeline takeaway capacity. Weak international naphtha demand, which impacts the price of USGC condensate that is exported to Canada, has further weighed on prices in the second quarter of 2024.

Refining Benchmarks

RUL and ULSD benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 market crack spread. The 3-2-1 market crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel, using current-month WTI-based crude oil feedstock prices and valued on a last in, first out basis.

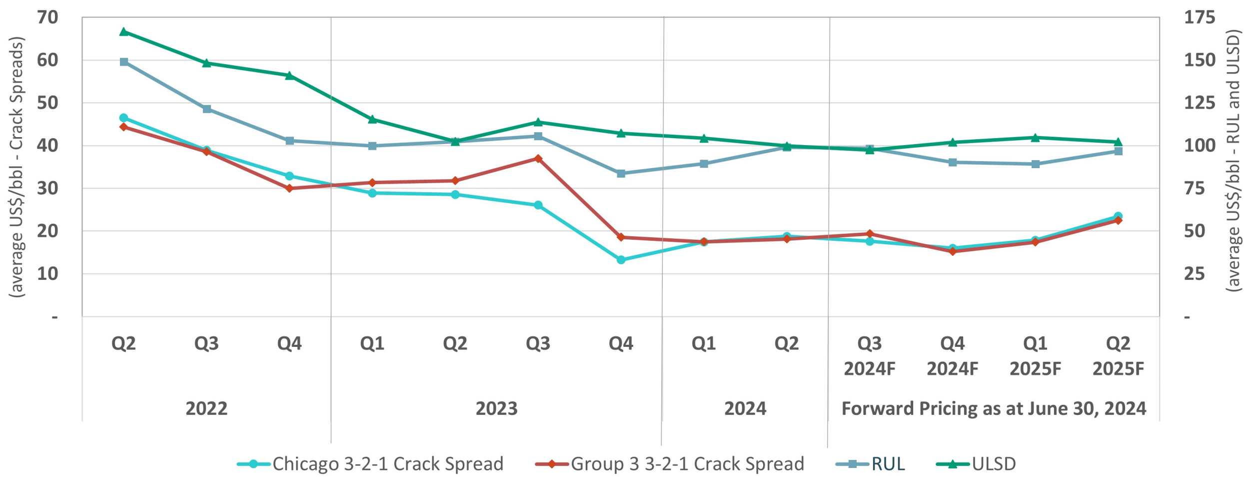
Refined product prices declined in the three and six months ended June 30, 2024, compared with 2023, as incremental global capacity additions weighed on global refinery crack spreads, and U.S. refineries operated at very high utilization rates. Excess supply of refined products and large inventory builds in the U.S. Midwest pressured Chicago pricing relative to other markets in the beginning of 2024; however, this was offset by periods of relative strength due to planned and unplanned refinery maintenance in the region during the first half of 2024.

The average RINs costs were also lower in the three and six months ended June 30, 2024, compared with the same periods of 2023 due to growing renewable diesel supply.

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 reflect the differential between Brent and WTI benchmark prices.

Our refining margins are affected by various other factors such as the quality and purchase location of crude oil feedstock, refinery configuration and product output, and the time lag between the purchase of feedstock and the product sale, as the feedstock is valued on a first in, first out (“FIFO”) accounting basis. The market crack spreads do not precisely mirror the configuration and product output of our refineries; however, they are used as a general market indicator.

Refined Product Benchmarks



Natural Gas Benchmarks

In the three and six months ended June 30, 2024, average NYMEX and AECO natural gas prices decreased compared with 2023, due to high U.S. supply, a mild winter and high levels of inventory. AECO prices weakened further relative to NYMEX natural gas due to limited Western Canadian takeaway capacity. The price received for our Asia Pacific natural gas production is largely based on long-term contracts.

Foreign Exchange Benchmarks

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

In the three and six months ended June 30, 2024, on average, the Canadian dollar weakened relative to the U.S. dollar, compared with the same periods of 2023, positively impacting our reported revenues. The Canadian dollar weakened relative to the U.S. dollar as at June 30, 2024, compared with December 31, 2023, resulting in unrealized foreign exchange impacts on the translation of our U.S. dollar debt.

A portion of our long-term sales contracts in the Asia Pacific region are priced in RMB. An increase in the value of the Canadian dollar relative to the RMB will decrease the revenues received in Canadian dollars from the sale of natural gas commodities in the region. In the three and six months ended June 30, 2024, on average, the Canadian dollar strengthened relative to RMB, compared with the same periods 2023, negatively 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 June 30, 2024, the Bank of Canada’s Policy Interest Rate was 4.75 percent. On July 24, 2024, the Bank of Canada reduced the overnight rate by 25 basis points to 4.50 percent.

OUTLOOK

Commodity Price Outlook

Global crude oil prices increased quarter over quarter, as continued extensions of OPEC+ production cuts have supported prices. The current voluntary cuts have been extended to the end of the third quarter of 2024 and the group has indicated plans to gradually unwind voluntary cuts over 12 months starting October 2024. Non-OPEC+ supply growth, led by U.S. shale, has been robust and is expected to continue to grow through 2024, though slowing U.S. drilling activity since 2023 has softened the expectations for U.S. supply growth modestly. Demand growth has also been strong, boosted by Chinese consumption. With global crude oil supply and demand balances tight, and high Middle East spare production capacity, OPEC+ policy remains crucial to global oil balances and prices. Current geopolitical risks are causing volatility in global oil prices, with any escalation causing global oil prices to rise and any de-escalation causing prices to settle.

Crude oil price trajectory remains uncertain and volatile amid a market with unpredictable key drivers and government policy playing a large role in supply and demand dynamics. Policies regarding Russia, Iran and Venezuela are among key factors that will drive energy supply and shift global trade patterns. Overall, we expect the general outlook for crude oil and refined product prices will be volatile and impacted by OPEC+ policy, the duration and severity of the ongoing Russian invasion of Ukraine, the extent to which Russian exports are reduced by sanctions or production cuts, the pace of non-OPEC+ supply growth, the refilling of the strategic petroleum reserve, the crisis in Israel and Gaza including any spread to a wider conflict, Iran, attacks on vessels in the Red Sea, and tensions between Venezuela and Guyana. In addition, weakening global economic activity, inflation and interest rate uncertainty, and the potential for a recession, remain a risk to the pace of demand growth.

Refined product prices have declined from elevated levels in 2022 and 2023 as a result of incremental global capacity additions and U.S. refineries operating at very high utilization rates. This has led to storage of gasoline and diesel increasing from low levels. Utilization is expected to remain high through the peak demand summer months, keeping refining margins steady.

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

- We expect the WTI-WCS at Hardisty differential will remain largely tied to global supply factors and heavy crude oil processing capacity, as long as supply stays within Canadian crude oil export capacity. As expected, the start-up of TMX in 2024 is having a narrowing impact on WTI-WCS differentials.
- We expect refined product prices will remain volatile. Economic effects of the ongoing Russian invasion of Ukraine and central bank policies could impact demand. Refined product prices and market crack spreads are likely to continue to fluctuate, adjusting for seasonal trends and refinery utilization in North America and globally.
- NYMEX and AECO natural gas prices are expected to remain under pressure in the near-term due to strong supply and ample natural gas in storage. Weather will continue to be a key driver of demand and impact prices.
- We expect the Canadian dollar to continue to be impacted by the pace at which the U.S. Federal Reserve Board and the Bank of Canada raise or lower benchmark lending rates relative to each other, crude oil prices and emerging macro-economic factors.

Most of our upstream crude oil and downstream refined product production are exposed to movements in the WTI crude oil price. Our integrated upstream and downstream operations help us to mitigate the impact of commodity price volatility. Crude oil production in our upstream assets is blended with condensate and butane and used as crude oil feedstock by our downstream operations, and condensate extracted from our blended crude oil is sold back to our Oil Sands operations.

Our refining capacity is focused in the U.S. Midwest, along with smaller exposures in the USGC and Alberta, exposing Cenovus to the market crack spreads in all of these markets. We will continue to monitor market fundamentals and optimize run rates at our refineries accordingly.

Our exposure to crude differentials includes light-heavy and light-medium price differentials. The light-medium price differential exposure is focused on light-medium crudes in the U.S. Midwest market region where we have the majority of our refining capacity, and to a lesser degree, in the USGC and Alberta. Our exposure to light-heavy crude oil price differentials is composed of a global light-heavy component, a regional component in markets we transport barrels to, as well as the Alberta differentials, which could be subject to transportation constraints. While we expect to see volatility in crude oil prices, we have the ability to partially mitigate the impact of crude oil and refined product differentials through the following:

- Transportation commitments and arrangements – using our existing firm service commitments for takeaway capacity and supporting transportation projects that move crude oil from our production areas to consuming markets, including tidewater markets.
- Integration – heavy oil refining capacity allows us to capture value from both the WTI-WCS differential for Canadian crude oil, as well as from spreads on refined products.
- Monitoring market fundamentals and optimizing run rates at our refineries accordingly.
- Traditional crude oil storage tanks in various geographic locations.

Key Priorities for 2024

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

Top Tier Safety Performance

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

Returns to Shareholders Target

Maintaining a strong balance sheet with the resilience to withstand price volatility and capitalize on opportunities throughout the commodity price cycle is a key element of Cenovus's capital allocation framework. In July, we achieved our Net Debt target of $4.0 billion. As a result, we will target to allocate 100 percent of Excess Free Funds Flow in the third quarter to shareholder returns through share buybacks and/or variable dividends, reduced by the amount by which Net Debt exceeds $4.0 billion at the applicable previous quarter's end. For further details, see the Liquidity and Capital Resources section of this MD&A.

Project Execution

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

Cost Leadership

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

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

Sustainability

Sustainability is central to Cenovus's culture. We have established ambitious targets in our five environmental, social and governance ("ESG") focus areas and continue to allocate resources and progress tangible plans to meet 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.

2024 Corporate Guidance

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

Changes to our updated guidance include:

- An increase at the midpoint of total Upstream production due to strong year-to-date performance and reliability.
- An increase at the midpoint of total Downstream throughput due to strong year-to-date performance and optimization of turnaround activities in the second half of the year, including a turnaround that was deferred to 2025.

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

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

We continue to execute our capital program and there have been no changes to our full year expected capital investment range of $4.5 billion to $5.0 billion. This includes $3.0 billion directed towards sustaining production and supporting continued safe and reliable operations, and between $1.5 billion and $2.0 billion in optimization and growth capital.

REPORTABLE SEGMENTS

UPSTREAM

Oil Sands

In the second quarter of 2024, we:

- Delivered safe and reliable operations.
- Produced 609.8 thousand barrels of crude oil per day (2023 – 571.6 thousand barrels of crude oil per day).
- Delivered successful results from our sustaining, redevelopment and base well optimization programs at our Foster Creek, Christina Lake, Sunrise and Lloydminster thermal assets.
- Generated Operating Margin of $2.7 billion, an increase of $712 million, compared with the second quarter of 2023, primarily due to higher realized sales prices and lower operating expenses.
- Invested capital of $613 million primarily for sustaining activities and growth projects. Sustaining activities include the drilling of stratigraphic test wells as part of our integrated winter program. Growth projects include the tie-back of Narrows Lake to Christina Lake and optimization projects at Foster Creek and Sunrise.
- Earned a Netback of $52.10 per BOE (2023 – $38.49 per BOE).

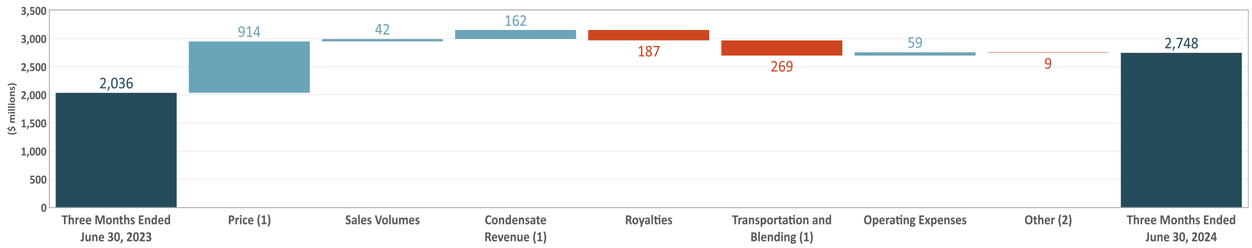
Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2024**	2023	**2024**	2023
Gross Sales [(1)]				
External Sales	**6,056**	5,177	**11,069**	10,009
Intersegment Sales	**1,497**	1,260	**3,112**	2,135
	7,553	6,437	**14,181**	12,144
Royalties	**(814)**	(620)	**(1,511)**	(1,136)
Revenues	**6,739**	5,817	**12,670**	11,008
Expenses				
Purchased Product [(1)]	**403**	414	**692**	769
Transportation and Blending	**2,953**	2,700	**5,686**	5,641
Operating	**615**	676	**1,275**	1,413
Realized (Gain) Loss on Risk Management	**20**	(9)	**33**	(1)
Operating Margin	**2,748**	2,036	**4,984**	3,186
Unrealized (Gain) Loss on Risk Management	**1**	31	**(12)**	(3)
Depreciation, Depletion and Amortization	**772**	730	**1,546**	1,445
Exploration Expense	**1**	2	**4**	4
(Income) Loss from Equity-Accounted Affiliates	**(14)**	6	**(14)**	6
Segment Income (Loss)	**1,988**	1,267	**3,460**	1,734

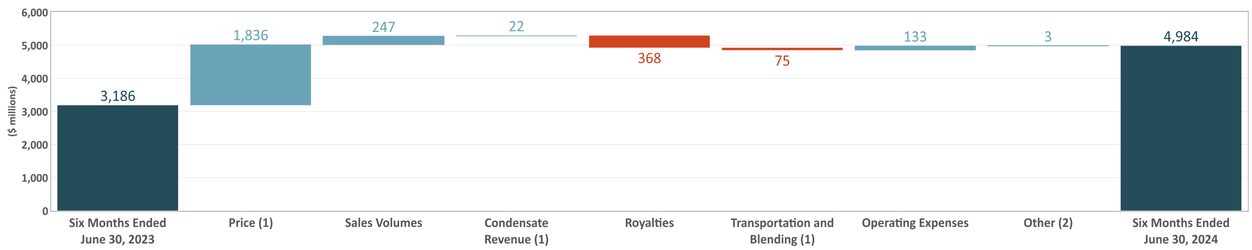
(1) Comparative periods reflect certain revisions. See Note 24 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Operating Margin Variance

Three Months Ended June 30, 2024



Six Months Ended June 30, 2024



(1) Reported revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expenses. The crude oil price excludes the impact of condensate purchases. Changes to price include the impact of realized risk management gains and losses.
(2) Includes third-party sourced volumes, construction and other activities not attributable to the production of crude oil, NGLs or natural gas.

Operating Results

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	**2024**	2023
Total Sales Volumes [1] (MBOE/d)	**584.5**	578.1	**595.6**	577.5
Realized Sales Price [2] [3] ($/BOE)	**88.76**	71.03	**80.62**	63.37
Crude Oil Production by Asset (Mbbls/d)				
Foster Creek	**195.0**	167.0	**195.5**	178.4
Christina Lake	**237.1**	234.9	**236.8**	236.0
Sunrise	**46.1**	46.5	**47.4**	45.5
Lloydminster Thermal	**113.5**	106.2	**113.8**	102.6
Lloydminster Conventional Heavy Oil	**18.1**	17.0	**18.0**	16.9
Total Crude Oil Production [4] (Mbbls/d)	**609.8**	571.6	**611.5**	579.4
Natural Gas [5] (MMcf/d)	**10.5**	12.9	**11.2**	12.7
Total Production (MBOE/d)	**611.5**	573.8	**613.4**	581.6

(1) Bitumen, heavy crude oil and natural gas.
(2) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(3) Comparative periods reflect certain revisions. See Note 24 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.
(4) Oil Sands production is primarily bitumen, except for Lloydminster conventional heavy oil, which is heavy crude oil.
(5) Conventional natural gas product type.

Operating Results – Continued

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	**2024**	2023
Effective Royalty Rate [1] (percent)				
Foster Creek	**21.1**	21.9	**22.9**	22.5
Christina Lake	**25.9**	24.6	**25.5**	27.0
Sunrise	**7.3**	5.4	**5.8**	5.2
Lloydminster [2]	**11.2**	9.3	**9.2**	8.9
Total Effective Royalty Rate	**19.4**	18.7	**19.4**	19.8
Transportation and Blending Expense [3] ($/BOE)	**9.98**	8.04	**8.74**	8.55
Operating Expense [3] ($/BOE)	**11.47**	12.72	**11.67**	13.37
Per-Unit DD&A [3] ($/BOE)	**13.68**	13.00	**13.51**	12.87

(1) Effective royalty rates are equal to royalty expense divided by product revenue, net of transportation expenses, excluding realized (gain) loss on risk management.
(2) Composed of Lloydminster thermal and Lloydminster conventional heavy oil assets.
(3) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Revenues

Gross sales increased for the three and six months ended June 30, 2024, compared with 2023, due to higher WTI benchmark prices, a narrowing of the WTI-WCS differential at Hardisty and increased sales volumes.

Price

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

For the three and six months ended June 30, 2024, approximately 29 percent and 26 percent, respectively, of our crude oil sales volumes were sold at U.S. destinations. For both the three and six months ended June 30, 2024, approximately 20 percent of our Oil Sands crude oil sales volumes were sold to our Canadian and U.S. downstream operations.

Our realized sales price averaged $88.76 per BOE and $80.62 per BOE, respectively, in the three and six months ended June 30, 2024, (2023 – $71.03 per BOE and $63.37 per BOE, respectively), mainly due to higher WTI benchmark prices, narrower WTI-WCS and condensate-WCS differentials.

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

Production Volumes

In the three and six months ended June 30, 2024, Oil Sands crude oil production was 609.8 thousand barrels per day and 611.5 thousand barrels per day, respectively, (2023 – 571.6 thousand barrels per day and 579.4 thousand barrels per day, respectively) mainly due to increases at our Foster Creek and Lloydminster thermal assets, while production volumes remained relatively consistent at our other Oil Sands assets.

Production at Foster Creek increased by 28.0 thousand barrels per day and 17.1 thousand barrels per day in the three and six months ended June 30, 2024, respectively, compared with 2023. The increases were primarily due to three new well pads that were brought online in 2023, one new pad brought online in the first quarter of 2024, and successful results from our redevelopment program. In addition, we had a turnaround in the second quarter of 2023.

Production from our Lloydminster thermal assets increased 7.3 thousand barrels per day and 11.2 thousand barrels per day in the three and six months ended June 30, 2024, respectively, compared with 2023. The increases were primarily due to successful results from the 2023 redevelopment program and base well optimizations.

Royalties

Royalty calculations for our Oil Sands segment are based on government prescribed royalty regimes in Alberta and Saskatchewan.

Our Alberta oil sands royalty projects (Foster Creek, Christina Lake and Sunrise) are based on government prescribed pre- and post-payout royalty rates, which are determined on a sliding scale using the Canadian dollar equivalent WTI benchmark price.

Royalties for a pre-payout project are based on a monthly calculation that applies a royalty rate (ranging from one percent to nine percent, based on the Canadian dollar equivalent WTI benchmark price) to the gross revenues from the project.

Royalties for a post-payout project are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one percent to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net revenues of the project multiplied by the applicable royalty rate (25 percent to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales revenues less diluent costs and transportation costs. Net revenues are calculated as sales revenues less diluent costs, transportation costs, and allowed operating and capital costs.

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

For our Saskatchewan assets, Lloydminster thermal and Lloydminster conventional heavy oil, royalty calculations are based on an annual rate that is applied to each project, which includes each project's Crown and freehold split. For Crown royalties, the pre-payout calculation is based on one percent of product revenues and the post-payout calculation is based on 20 percent of operating margin. The freehold calculation is limited to post-payout projects and is based on an eight percent rate.

Oil Sands royalties increased compared with 2023. For the three months ended June 30, 2024, the Oil Sands effective royalty rate increased to 19.4 percent from 18.7 percent in 2023, primarily due to higher realized prices combined with higher Alberta sliding scale oil sands royalty rates. For the six months ended June 30, 2024, the Oil Sands effective royalty rate decreased to 19.4 percent from 19.8 percent in 2023, primarily due to annual adjustments on the end-of-period filings.

Expenses

Transportation and Blending

In the second quarter of 2024, blending expenses increased $159 million to $2.4 billion compared with 2023, due to higher condensate prices and higher sales volumes. In the first half of 2024, blending expenses increased $17 million to $4.7 billion compared with 2023, due to higher sales volumes partially offset by lower condensate prices.

Transportation expenses increased in the three months ended June 30, 2024, due to higher sales volumes exported to destinations outside of Alberta compared with 2023. In the quarter, we started to ramp up our position on TMX, which resulted in higher transportation expenses.

Per-Unit Transportation Expenses

Per-unit transportation expenses increased in the three and six months ended June 30, 2024, compared with the same periods in 2023, due to higher transportation expenses discussed above, partially offset by higher sales volumes.

At Foster Creek, per-unit transportation expenses were $14.69 per barrel and $12.42 per barrel in the three and six months ended June 30, 2024, respectively (2023 – $12.80 per barrel and $13.13 per barrel, respectively). The quarter-over-quarter increase was primarily due to higher transportation expenses as we ramp up the use of TMX, partially offset by higher sales volumes. The year-over-year decrease was primarily due to lower sales to destinations outside of Alberta and an increase in sales volumes, partially offset by increased TMX expenses as discussed above. In the three and six months ended June 30, 2024, we shipped 49 percent and 41 percent, respectively (2023 – 47 percent and 48 percent, respectively) of our volumes from Foster Creek to destinations outside of Alberta.

At Christina Lake, per-unit transportation expenses were $7.16 per barrel and $6.23 per barrel in the three and six months ended June 30, 2024, respectively (2023 – $5.91 per barrel and $6.81 per barrel, respectively). The quarter-over-quarter increase was primarily due to higher sales to U.S. destinations and increased tariff rates, partially offset by lower rail costs. The year-over-year decrease was primarily due to lower rail costs. In the three and six months ended June 30, 2024, we shipped 23 percent and 17 percent, respectively (2023 – 17 percent and 18 percent, respectively) of our volumes from Christina Lake to U.S. destinations.

At Sunrise, per-unit transportation expenses increased in the three and six months ended June 30, 2024, compared with 2023, primarily due to higher transportation costs for the use of TMX and higher sales outside of Alberta. In both the three and six months ended June 30, 2024, we shipped 94 percent (2023 – 50 percent and 48 percent, respectively) of our volumes from Sunrise to destinations outside of Alberta.

At Lloydminster, per-unit transportation expenses increased in the three and six months ended June 30, 2024, mainly due to higher tariff rates for higher sales volumes being sent to U.S. destinations, compared with 2023. In the three and six months ended June 30, 2024, we shipped six percent and five percent, respectively, to U.S. destinations (2023 – nil for both periods).

Operating

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

Per-Unit Operating Expenses [(1)]

	Three Months Ended June 30,			Six Months Ended June 30,		
($/BOE)	**2024**	**Percent Change**	2023	**2024**	**Percent Change**	2023
Foster Creek						
Fuel	**1.95**	**(43)**	3.40	**2.60**	**(39)**	4.27
Non-Fuel	**8.11**	**(8)**	8.81	**7.84**	**(6)**	8.34
Total	**10.06**	**(18)**	12.21	**10.44**	**(17)**	12.61
Christina Lake						
Fuel	**1.91**	**(31)**	2.77	**2.36**	**(28)**	3.26
Non-Fuel	**6.58**	**24**	5.32	**6.14**	**15**	5.34
Total	**8.49**	**5**	8.09	**8.50**	**(1)**	8.60
Sunrise						
Fuel	**3.04**	**(33)**	4.52	**3.61**	**(34)**	5.49
Non-Fuel	**10.13**	**(21)**	12.86	**11.30**	**(19)**	14.00
Total	**13.17**	**(24)**	17.38	**14.91**	**(23)**	19.49
Lloydminster [(2)]						
Fuel	**2.25**	**(43)**	3.97	**3.20**	**(35)**	4.91
Non-Fuel	**15.56**	**(5)**	16.33	**14.73**	**(12)**	16.73
Total	**17.81**	**(12)**	20.30	**17.93**	**(17)**	21.64
Total Oil Sands						
Fuel	**2.10**	**(38)**	3.36	**2.72**	**(33)**	4.09
Non-Fuel	**9.37**	**—**	9.36	**8.95**	**(4)**	9.28
Total	**11.47**	**(10)**	12.72	**11.67**	**(13)**	13.37

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

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

Foster Creek per-unit non-fuel expenses decreased in the three and six months ended June 30, 2024, compared with 2023, due to increased sales volumes, partially offset by increased repairs and maintenance costs, workover activity and GHG compliance costs.

Christina Lake per-unit non-fuel expenses increased in the three and six months ended June 30, 2024, compared with 2023, due to increased repairs and maintenance costs, workover activity and decreased sales volumes.

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

Lloydminster per-unit non-fuel expenses decreased in the three and six months ended June 30, 2024, compared with 2023, due to increased sales volumes, combined with lower workover activity and chemical costs partially offset by increased GHG compliance costs.

Netbacks [1]

($/BOE)	Three Months Ended June 30, 2024	2023	Six Months Ended June 30, 2024	2023
Sales Price	**88.76**	71.03	**80.62**	63.37
Royalties	**15.21**	11.78	**13.88**	10.87
Transportation and Blending	**9.98**	8.04	**8.74**	8.55
Operating Expenses	**11.47**	12.72	**11.67**	13.37
Netback	**52.10**	38.49	**46.33**	30.58

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

Conventional

In the second quarter of 2024, we:

- Delivered safe and reliable operations.
- Produced 123.1 thousand BOE per day (2023 – 104.6 thousand BOE per day).
- Generated Operating Margin of $42 million, a decrease of $31 million from the second quarter of 2023.
- Invested capital of $68 million with a continued focus on drilling, completion, tie-in and infrastructure projects.
- Averaged a Netback of $3.68 per BOE (2023 – $5.89 per BOE).

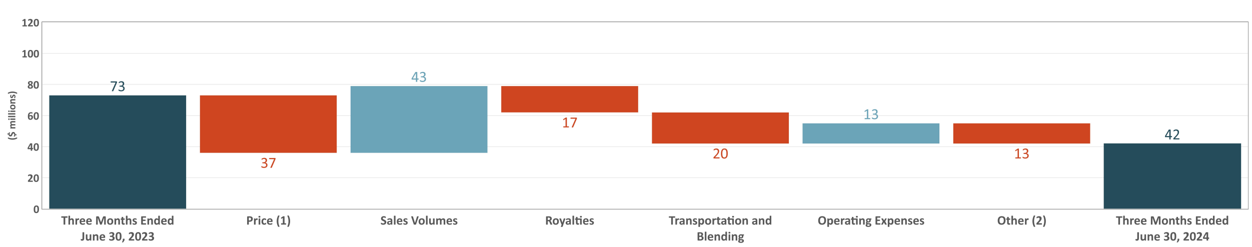
Financial Results

($ millions)	Three Months Ended June 30, 2024	2023	Six Months Ended June 30, 2024	2023
Gross Sales [1]				
External Sales	**264**	253	**641**	875
Intersegment Sales	**427**	367	**929**	782
	691	620	**1,570**	1,657
Royalties	**(22)**	(4)	**(46)**	(58)
Revenues	**669**	616	**1,524**	1,599
Expenses				
Purchased Product [1]	**412**	337	**894**	820
Transportation and Blending [1]	**83**	66	**161**	147
Operating	**132**	144	**285**	294
Realized (Gain) Loss on Risk Management	**—**	(4)	**(7)**	4
Operating Margin	**42**	73	**191**	334
Unrealized (Gain) Loss on Risk Management	**2**	(1)	**8**	(21)
Depreciation, Depletion and Amortization	**111**	87	**221**	182
(Income) Loss From Equity-Accounted Affiliates	**—**	—	**1**	—
Segment Income (Loss)	**(71)**	(13)	**(39)**	173

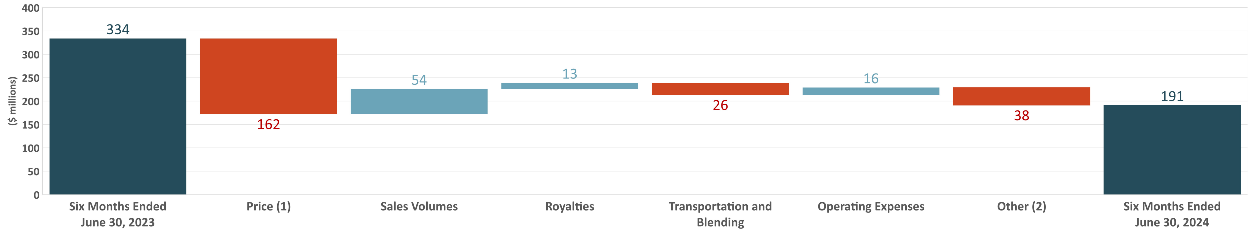
(1) Comparative periods reflect certain revisions. See Note 24 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Operating Margin Variance

Three Months Ended June 30, 2024



Six Months Ended June 30, 2024



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

Operating Results

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	**2024**	2023
Total Sales Volumes (MBOE/d)	**123.1**	104.6	**121.9**	114.2
Realized Sales Price (1) (2) ($/BOE)	**22.20**	25.09	**27.50**	35.29
Light Crude Oil ($/bbl)	**98.12**	104.40	**92.96**	103.48
NGLs ($/bbl)	**56.29**	46.59	**56.86**	47.39
Conventional Natural Gas ($/Mcf)	**1.77**	2.63	**2.87**	4.71
Production by Product				
Light Crude Oil (Mbbls/d)	**5.1**	4.8	**5.2**	5.6
NGLs (Mbbls/d)	**21.4**	18.0	**21.7**	20.0
Conventional Natural Gas (MMcf/d)	**579.4**	491.4	**569.9**	531.9
Total Production (MBOE/d)	**123.1**	104.6	**121.9**	114.2
Conventional Natural Gas Production (percentage of total)	**78**	78	**78**	78
Crude Oil and NGLs Production (percentage of total)	**22**	22	**22**	22
Effective Royalty Rate (3) (percent)	**12.4**	2.5	**11.0**	11.5
Transportation Expense (2) (4) ($/BOE)	**5.25**	4.08	**4.97**	4.05
Operating Expense (4) ($/BOE)	**11.25**	14.59	**12.14**	13.77
Per-Unit DD&A (4) ($/BOE)	**9.88**	9.01	**9.89**	8.76

(1) *Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.*
(2) *Comparative periods reflect certain revisions. See Note 24 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.*
(3) *Effective royalty rates are equal to royalty expense divided by product revenue, net of transportation expenses, excluding realized (gain) loss on risk management.*
(4) *Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.*

Revenues

For the three and six months ended June 30, 2024, gross sales were $691 million and $1.6 billion, respectively (2023 – $620 million and $1.7 billion, respectively). The quarter-over-quarter increase was due to increased sales volumes offset by a decline in natural gas benchmark pricing. The year-over-year decrease was primarily due to a decline in natural gas benchmark pricing, partially offset by increased sales volumes.

Price

Our total realized sales price decreased primarily due to lower natural gas benchmark prices. For the three and six months ended June 30, 2024, the AECO benchmark price declined 52 percent and 35 percent, respectively, compared with the same periods in 2023.

Production Volumes

For the three and six months ended June 30, 2024, production volumes increased 18.5 thousand BOE per day and 7.7 thousand BOE per day, respectively, compared with the same periods in 2023. The increases were largely driven by the successful restart of operations following wildfire activity in May and June of 2023 that temporarily shut-in production, partially offset by the divestiture of certain Clearwater and Edson assets in the first quarter of 2024.

Royalties

The Conventional assets are subject to royalty regimes in Alberta and British Columbia. Royalties increased quarter-over-quarter mainly due to higher production volumes, partially offset by lower natural gas benchmark pricing and the divestiture of certain assets discussed above. Royalties decreased year-over-year due to lower natural gas benchmark prices and the divestiture of certain assets, as discussed above, which more than offset the increase in production volumes.

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 six months ended June 30, 2024, transportation expenses increased primarily due to increased tariff rates, compared with 2023. The per-unit transportation expenses increased due to higher transportation expenses, partially offset by increased sales volumes.

Operating

Primary drivers of operating expenses in the first six months of 2024 were repairs and maintenance, workforce and property tax costs. In the three and six months ended June 30, 2024, total operating expenses decreased $12 million and $9 million, respectively, compared with the same periods in 2023, primarily due to the divestiture of assets discussed above. Operating expenses per BOE decreased $3.34 per BOE quarter-over-quarter and $1.63 year-over-year, due to lower costs and higher sales volumes.

Netbacks (1)

	Three Months Ended June 30,		**Six Months Ended June 30,**	
($/BOE)	**2024**	2023	**2024**	2023
Sales Price (2)	**22.20**	25.09	**27.50**	35.29
Royalties	**2.02**	0.53	**2.09**	2.84
Transportation and Blending (2)	**5.25**	4.08	**4.97**	4.05
Operating Expenses	**11.25**	14.59	**12.14**	13.77
Netback	**3.68**	5.89	**8.30**	14.63

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

(2) Comparative periods reflect certain revisions. See Note 24 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Offshore

In the second quarter of 2024, we:

- Delivered safe and reliable operations.
- Produced 66.2 thousand BOE per day of light crude oil, NGLs and natural gas (2023 – 51.5 thousand BOE per day).
- Generated Operating Margin of $299 million, an increase of $151 million from the second quarter of 2023, mainly due to higher sales volumes in the Atlantic region and in China, and higher Brent benchmark pricing.
- Earned a Netback of $54.33 per BOE (2023 – $45.11 per BOE).
- Invested capital of $295 million, mainly related to the progression of the West White Rose project, SeaRose ALE project and commenced drilling an exploration well in China.

In late December 2023, we suspended production at the White Rose field as we prepared for the planned SeaRose ALE project. Refit work commenced in the first quarter of 2024 and continues to progress. The SeaRose FPSO is expected to return to the White Rose field late in the third quarter of 2024, with production resuming in the fourth quarter.

In the second quarter of 2024, the West White Rose project reached a significant milestone with the completion of major construction on two key components of the platform. The concrete gravity structure reached its final height, and the last crane was installed, completing the topsides structurally. The focus will now be on interior completion and commissioning of the structures. The West White Rose project was approximately 80 percent complete as at June 30, 2024. Since our decision in 2022 to restart the project, we have invested approximately $984 million. First oil is expected in 2026.

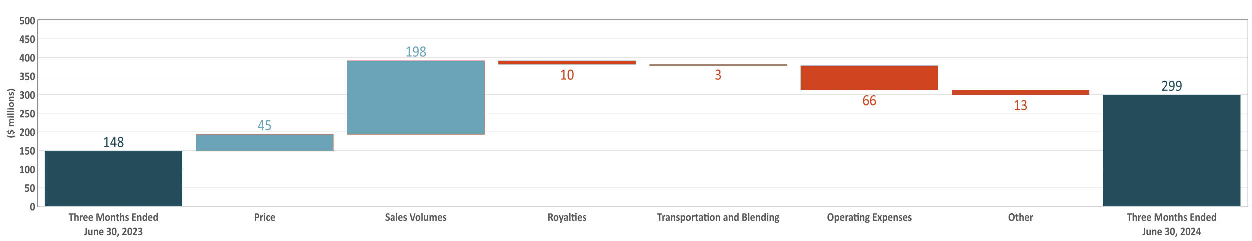
Financial Results

	Three Months Ended June 30,					
	2024			2023		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore**	Atlantic	Asia Pacific	Offshore
Gross Sales						
External Sales	**151**	**320**	**471**	5	223	228
Intersegment Sales	**—**	**—**	**—**	—	—	—
	151	**320**	**471**	5	223	228
Royalties	**1**	**(24)**	**(23)**	(1)	(12)	(13)
Revenues	**152**	**296**	**448**	4	211	215
Expenses						
Transportation and Blending	**7**	**—**	**7**	4	—	4
Operating	**110**	**32**	**142**	26	37	63
Operating Margin [(1)]	**35**	**264**	**299**	(26)	174	148
Depreciation, Depletion and Amortization			**156**			91
Exploration Expense			**4**			2
(Income) Loss from Equity-Accounted Affiliates			**(13)**			(12)
Segment Income (Loss)			**152**			67

(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 June 30, 2024



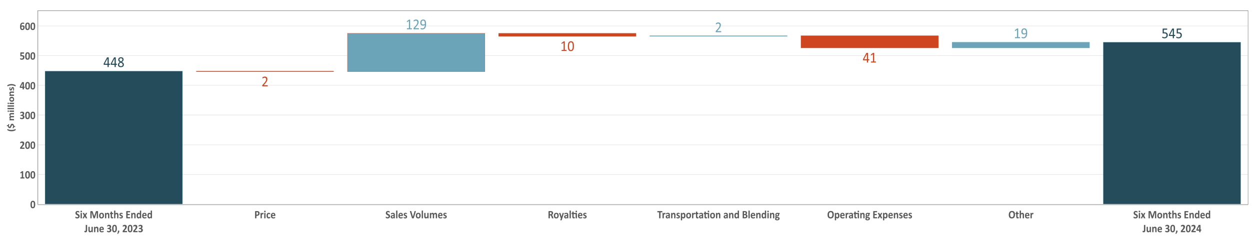
Financial Results

($ millions)	Six Months Ended June 30, 2024 Atlantic	2024 Asia Pacific	2024 Offshore	2023 Atlantic	2023 Asia Pacific	2023 Offshore
Gross Sales						
External Sales	**193**	**635**	**828**	154	547	701
Intersegment Sales	**—**	**—**	**—**	—	—	—
	193	**635**	**828**	154	547	701
Royalties	**(1)**	**(48)**	**(49)**	(9)	(30)	(39)
Revenues	**192**	**587**	**779**	145	517	662
Expenses						
Transportation and Blending	**7**	**—**	**7**	9	—	9
Operating	**167**	**60**	**227**	143	62	205
Operating Margin (1)	**18**	**527**	**545**	(7)	455	448
Depreciation, Depletion and Amortization			**287**			219
Exploration Expense			**8**			4
(Income) Loss from Equity-Accounted Affiliates			**(23)**			(18)
Segment Income (Loss)			**273**			243

(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

Six Months Ended June 30, 2024



Operating Results

	Three Months Ended June 30, 2024	Three Months Ended June 30, 2023	Six Months Ended June 30, 2024	Six Months Ended June 30, 2023
Sales Volumes				
Atlantic (Mbbls/d)	**14.8**	—	**9.4**	7.8
Asia Pacific (MBOE/d)				
China	**43.5**	31.2	**43.6**	37.2
Indonesia (1)	**14.3**	15.0	**14.2**	14.3
Total Asia Pacific	**57.8**	46.2	**57.8**	51.5
Total Sales Volumes (MBOE/d)	**72.6**	46.2	**67.2**	59.3
Realized Sales Price (1) (2) ($/BOE)	**83.38**	73.12	**79.75**	79.51
Atlantic - Light Crude Oil ($/bbl)	**112.74**	—	**113.02**	108.73
Asia Pacific (1) ($/BOE)	**75.87**	71.86	**74.36**	75.07
NGLs ($/bbl)	**102.45**	84.95	**99.52**	91.43
Conventional Natural Gas ($/Mcf)	**11.53**	11.47	**11.40**	11.85

(1) *Reported sales volumes, associated per-unit values and royalty rates reflect Cenovus's 40 percent interest in HCML. The HCML joint venture is accounted for using the equity method in the interim Consolidated Financial Statements.*
(2) *Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.*

Operating Results – Continued

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	**2024**	2023
Production by Product				
Atlantic - Light Crude Oil (Mbbls/d)	**8.4**	5.3	**7.8**	7.1
Asia Pacific (1)				
NGLs (Mbbls/d)	**11.6**	8.7	**11.1**	10.0
Conventional Natural Gas (MMcf/d)	**277.3**	225.1	**280.4**	248.5
Total Asia Pacific (MBOE/d)	**57.8**	46.2	**57.8**	51.5
Total Production (MBOE/d)	**66.2**	51.5	**65.6**	58.6
Effective Royalty Rate (2) (percent)				
Atlantic	**(0.6)**	—	**0.5**	5.3
Asia Pacific (1)	**9.5**	10.1	**8.6**	10.1
Operating Expense (3) ($/BOE)	**22.34**	19.48	**20.03**	18.88
Atlantic	**79.03**	—	**95.82**	85.02
Asia Pacific (1)	**7.84**	10.96	**7.74**	8.82
Per-Unit DD&A (3) ($/BOE)	**22.90**	25.31	**22.70**	25.81

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

Revenues

For the three and six months ended June 30, 2024, gross sales increased to $471 million and $828 million, respectively (2023 – $228 million and $701 million, respectively). The increases were due to an increase in sales volumes and an increase in realized sales price due to higher Brent benchmark pricing.

Price

Our Atlantic realized sales price on light crude oil increased in the three and six months ended June 30, 2024, primarily due to higher Brent benchmark pricing. The price we receive for natural gas sold in Asia Pacific is set under long-term contracts.

Production Volumes

Atlantic production increased 3.1 thousand BOE per day and 0.7 thousand BOE per day in the three and six months ended June 30, 2024, compared with 2023, primarily due to resuming production at the Terra Nova FPSO in November 2023, partially offset by the suspension of production at the White Rose field in December 2023 for the SeaRose ALE project. Light crude oil production from the White Rose and Terra Nova fields are offloaded from the SeaRose FPSO and the Terra Nova FPSO, respectively, to tankers and stored at an onshore terminal before shipment to buyers, which results in a timing difference between production and sales.

Asia Pacific production increased 11.6 thousand BOE per day and 6.3 thousand BOE per day in the three and six months ended June 30, 2024, respectively, compared with 2023. The increases were due to higher gas and NGL production in China following a temporary unplanned outage in second quarter of 2023, related to the disconnection of the umbilical by a third-party vessel, and first gas production at the MAC field in Indonesia in September 2023. The increases were partially offset by lower production in Indonesia due to lower gas demand and the timing of condensate lifts in the first half of 2024.

Royalties

In the second quarter of 2024, Atlantic royalties reflected a credit received for the 2023 White Rose annual royalty filing.

Royalty rates in China and Indonesia are governed by production sharing contracts, in which production is shared with the Chinese and Indonesian governments. The effective royalty rate for the three and six months ended June 30, 2024, declined to 9.5 percent and 8.6 percent, respectively (2023 – 10.1 percent and 10.1 percent, respectively). The quarter-over-quarter decrease was primarily due to lower sales volumes in Indonesia. The year-over-year decrease was primarily due to a production bonus paid to the Government of Indonesia for achieving a production milestone in the first quarter of 2023, partially offset by a consumption tax implemented in China in June 2023, which contributed to an increase in the NGL royalty rate.

Expenses

Transportation

Transportation expenses include the costs of transporting crude oil from the Terra Nova and SeaRose FPSO units to onshore via tankers, as well as storage costs. Transportation expenses in the three and six months ended June 30, 2024, were $7 million and $7 million, respectively (2023 – $4 million and $9 million, respectively). In the first six months of 2024, transportation costs were lower compared with 2023, due to a nominal recovery in the first quarter of 2024.

Operating

Primary drivers of our Atlantic operating expenses in the first six months of 2024 were repairs and maintenance, costs related to vessels and air services and workforce. In the second quarter of 2024, operating expenses increased by $84 million, compared with 2023, primarily due to increased sales volumes and costs related to the SeaRose ALE project. Operating expenses in the first six months of 2024 increased by $24 million, compared with 2023, primarily due to reasons discussed above. The increase was partially offset by costs related to the restart of the West White Rose project during the first half of 2023. Per-unit operating expenses increased in the three and six months ended June 30, 2024, compared with 2023, mainly due to an increase in operating expenses as discussed above, partially offset by increased sales volumes.

Primary drivers of our China operating expenses in the first six months of 2024 were repairs and maintenance, insurance and workforce costs. In the three and six months ended June 30, 2024, operating expenses decreased by $5 million and $2 million, respectively, compared with 2023, primarily due to additional costs incurred in the second quarter of 2023 related to the umbilical repair. Per-unit operating expenses associated with our assets in China decreased in the three and six months ended June 30, 2024, compared with 2023, due to decreased operating expenses as discussed above, and increased sales volumes. Per-unit operating expenses associated with our Indonesian assets increased in the three and six months ended June 30, 2024, compared with 2023. The MAC field was fully operational in the third quarter of 2023, which increased repairs and maintenance, and workforce expenses.

Netbacks (1)

	Three Months Ended June 30, 2024			
($/BOE, except where indicated)	**Atlantic** ($/bbl)	**China**	**Indonesia**	**Total Offshore** (2)
Sales Price	**112.74**	**80.95**	**60.43**	**83.38**
Royalties	**(0.72)**	**6.20**	**10.17**	**5.57**
Transportation and Blending	**5.60**	**—**	**—**	**1.14**
Operating Expenses	**79.03**	**7.24**	**9.68**	**22.34**
Netback	**28.83**	**67.51**	**40.58**	**54.33**

	Three Months Ended June 30, 2023			
($/BOE, except where indicated)	Atlantic (3) ($/bbl)	China	Indonesia	Total Offshore (2)
Sales Price	—	78.48	58.05	73.12
Royalties	—	4.23	13.60	7.47
Transportation and Blending	—	—	—	1.06
Operating Expenses	—	11.91	8.98	19.48
Netback	—	62.34	35.47	45.11

(1) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Reported sales volumes, associated per-unit values and royalty rates reflect Cenovus's 40 percent interest in HCML. The HCML joint venture is accounted for using the equity method in the interim Consolidated Financial Statements.
(3) No sales volumes from our Atlantic operations in the second quarter of 2023.

Netbacks – Continued [1]

($/BOE, except where indicated)	**Six Months Ended June 30, 2024** **Atlantic** ($/bbl)	**China**	**Indonesia**	**Total Offshore** [2]
Sales Price	**113.02**	**80.08**	**56.77**	**79.75**
Royalties	**0.50**	**6.10**	**7.17**	**5.54**
Transportation and Blending	**3.97**	**—**	**—**	**0.55**
Operating Expenses	**95.82**	**6.76**	**10.76**	**20.03**
Netback	**12.73**	**67.22**	**38.84**	**53.63**

($/BOE, except where indicated)	Six Months Ended June 30, 2023 Atlantic ($/bbl)	China	Indonesia	Total Offshore [2]
Sales Price	108.73	81.37	58.72	79.51
Royalties	6.14	4.44	15.83	7.42
Transportation and Blending	6.31	—	—	0.83
Operating Expenses	85.02	8.26	10.26	18.88
Netback	11.26	68.67	32.63	52.38

(1) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) Reported sales volumes, associated per-unit values and royalty rates reflect Cenovus's 40 percent interest in HCML. The HCML joint venture is accounted for using the equity method in the interim Consolidated Financial Statements.

DOWNSTREAM

Canadian Refining

In the second quarter of 2024, we:

- Delivered safe operations and safely executed the largest turnaround at the Upgrader in its history.
- Had throughput of 53.8 thousand barrels per day and crude unit utilization of 50 percent (2023 – 95.3 thousand barrels per day and 88 percent, respectively).
- Incurred operating expenses of $415 million, including turnaround costs of $211 million.
- Recorded a negative Operating Margin of $255 million, compared with a positive Operating Margin of $116 million in the second quarter of 2023.
- Invested capital of $70 million.

Financial Results

($ millions, except where indicated)	**Three Months Ended June 30,** **2024**	2023	**Six Months Ended June 30,** **2024**	2023
Gross Sales				
External Sales	**1,037**	1,151	**2,200**	2,453
Intersegment Sales	**98**	212	**267**	418
Revenues	**1,135**	1,363	**2,467**	2,871
Purchased Product	**975**	1,083	**2,062**	2,176
Gross Margin [1]	**160**	280	**405**	695
Expenses				
Operating	**415**	164	**592**	316
Operating Margin	**(255)**	116	**(187)**	379
Depreciation, Depletion and Amortization	**54**	43	**98**	86
Segment Income (Loss)	**(309)**	73	**(285)**	293

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

Operating Results

($ millions, except where indicated)	Three Months Ended June 30, 2024	2023	Six Months Ended June 30, 2024	2023
Operable Capacity [(1)] (Mbbls/d)	**108.0**	108.0	**108.0**	108.0
Total Processed Inputs [(2)] (Mbbls/d)	**58.9**	102.7	**83.8**	104.2
Crude Oil Unit Throughput (Mbbls/d)	**53.8**	95.3	**79.0**	97.0
Crude Unit Utilization [(3)] (percent)	**50**	88	**73**	90
Total Production (Mbbls/d)	**64.0**	108.3	**90.1**	110.6
Synthetic Crude Oil	**20.7**	44.8	**33.9**	45.2
Asphalt	**14.0**	15.3	**14.8**	15.5
Diesel	**5.2**	12.4	**9.0**	12.4
Other	**19.7**	31.9	**27.5**	33.0
Ethanol	**4.4**	3.9	**4.9**	4.5
Refining Margin [(4)] ($/bbl)	**25.21**	26.54	**23.57**	33.56

(1) Operable capacity is the capacity based on barrels per calendar day. It is the amount of input that a distillation facility can process under usual operating conditions. We previously reported crude oil name plate capacity.
(2) Total processed inputs include crude oil and other feedstocks. Blending is excluded.
(3) Crude unit utilization is calculated as crude oil unit throughput divided by operable capacity. Prior periods have been re-presented to align with this calculation.
(4) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A. Revenues from the Upgrader, commercial fuels business and the Lloydminster Refinery for the three and six months ended June 30, 2024, were $1.1 billion and $2.3 billion, respectively (2023 – $1.3 billion and $2.7 billion, respectively).

In the second quarter of 2024, we safely executed the largest turnaround in the history of the Upgrader, which ran from May 8 to July 4, 2024, with crude re-introduced in the first week of July. The turnaround significantly decreased throughput and increased operating expenses in the quarter.

In the six months ended June 30, 2024, throughput decreased, largely due to the turnaround, as discussed above, offset by high reliability in the first quarter of 2024.

Revenues and Gross Margin

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

The Lloydminster Refinery processes blended heavy crude oil into asphalt and industrial products. Gross margin is largely dependent on asphalt and industrial products pricing and the cost of heavy crude oil feedstock. Sales from the Lloydminster Refinery are seasonal and increase during paving season, which typically runs from May through October each year.

The Upgrader and Lloydminster Refinery source crude oil feedstock from our Oil Sands segment. In the three and six months ended June 30, 2024, approximately seven percent and 10 percent, respectively, of total crude oil sales volumes from our Oil Sands assets were sold to our Canadian Refining segment (three and six months ended June 30, 2023 – 13 percent).

For the three and six months ended June 30, 2024, revenues decreased $228 million and $404 million compared with the same periods in 2023, primarily due to lower refined product production. In the three months ended June 30, 2024, lower refined product production was offset by increased synthetic crude oil benchmark prices compared with 2023. In the six months ended June 30, 2024, synthetic crude oil benchmark prices were relatively consistent with the same period in 2023.

Gross Margin was $160 million and $405 million in the three and six months ended June 30, 2024, respectively. The decreases from the comparative periods in 2023 were primarily due to lower refined product production, partially offset by higher feedstock costs driven by the increase in the WTI benchmark price and the narrowing of the WTI-WCS differential at Hardisty. The WTI-WCS differential at Hardisty narrowed in the three and six month periods by 10 percent and 17 percent, respectively, compared with the same periods in 2023.

Operating Expenses

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions, except where indicated)	**2024**	2023	**2024**	2023
Operating Expenses (1)	**377**	131	**524**	256
Operating Expenses - Turnaround Costs	**211**	—	**226**	—
Per-Unit Operating Expenses (1) (2) ($/bbl)	**70.44**	14.05	**34.36**	13.59
Per-Unit Operating Expenses - Turnaround Costs (2)	**39.52**	—	**14.83**	—

(1) Represents operating expenses associated with the Lloydminster Upgrader, the Lloydminster Refinery and the commercial fuels business.

(2) Specified financial measure. The definition of Per-Unit Operating Expense has been revised to operating expenses divided by total processed inputs. Prior periods have been re-presented. The definition of Per-Unit Operating Expense – Turnaround Costs is operating expenses – turnaround costs divided by total processed inputs. See the Specified Financial Measures Advisory of this MD&A.

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

Operating expenses for the three and six months ended June 30, 2024, were largely composed of turnaround expenses of $211 million and $226 million, respectively (three and six months ended June 30, 2023 – $nil). Operating expenses in the second quarter also increased due to other projects that were completed during the turnaround period.

Per-unit operating expenses are calculated as operating expenses divided by total processed inputs. Total processed inputs reflect the overall inputs required to produce refined products in our refineries, and is used as the denominator in our per-unit measures. Per-Unit Operating Expenses increased in the three and six months ended June 30, 2024, compared with 2023, due to the Upgrader turnaround which increased costs and reduced total processed inputs.

U.S. Refining

In the second quarter of 2024, we:

- Had crude throughput of 568.9 thousand barrels per day (2023 – 442.5 thousand barrels per day), and achieved crude unit utilization of 93 percent (2023 – 72 percent).
- Generated an Operating Margin of $102 million, an increase of $75 million from the second quarter of 2023.
- Invested capital of $100 million, primarily focused on sustaining activities at the Toledo, Lima and Superior refineries, and refining reliability projects at the Wood River and Borger refineries.

Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions, except where indicated)	**2024**	2023	**2024**	2023
Gross Sales (1)				
External Sales	**7,916**	6,059	**15,150**	11,688
Intersegment Sales	**2**	5	**3**	5
Revenues	**7,918**	6,064	**15,153**	11,693
Purchased Product (1)	**7,124**	5,364	**13,256**	10,262
Gross Margin (2)	**794**	700	**1,897**	1,431
Expenses				
Operating	**684**	679	**1,294**	1,281
Realized (Gain) Loss on Risk Management	**8**	(6)	**9**	(5)
Operating Margin	**102**	27	**594**	155
Unrealized (Gain) Loss on Risk Management	**(10)**	(5)	**(2)**	(11)
Depreciation, Depletion and Amortization	**112**	102	**223**	205
Segment Income (Loss)	**—**	(70)	**373**	(39)

(1) Comparative periods reflect certain revisions. See Note 24 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

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

Operating Results

($ millions, except where indicated)	Three Months Ended June 30, 2024	2023	Six Months Ended June 30, 2024	2023
Operable Capacity [1] (Mbbls/d)	**612.3**	612.3	**612.3**	612.3
Total Processed Inputs [2] (Mbbls/d)	**594.0**	464.2	**584.5**	419.9
Crude Oil Unit Throughput (Mbbls/d)	**568.9**	442.5	**560.0**	401.1
Heavy Crude Oil	**219.4**	155.1	**222.1**	161.5
Light/Medium Crude Oil	**349.5**	287.4	**337.9**	239.6
Crude Unit Utilization [3] [4] (percent)	**93**	72	**91**	68
Total Production (Mbbls/d)	**595.5**	463.6	**590.7**	419.4
Gasoline	**278.3**	199.4	**280.1**	193.2
Distillates [5]	**216.3**	160.9	**208.2**	149.6
Asphalt	**26.2**	22.1	**26.2**	16.5
Other	**74.7**	81.2	**76.2**	60.1
Refining Margin [6] ($/bbl)	**14.69**	16.57	**17.83**	18.83
Weighted Average Crack Spread, Net of RINs [7] (US$/bbl)	**15.25**	21.47	**14.52**	21.31
Weighted Average Crack Spread, Net of RINs [7] (C$/bbl)	**20.86**	28.82	**19.72**	28.72
Market Capture [4] [6] [8] (percent)	**70**	57	**90**	66

(1) Operable capacity is the capacity based on barrels per calendar day. It is the amount of input that a distillation facility can process under usual operating conditions. We previously reported crude oil name plate capacity.
(2) Total processed inputs include crude oil and other feedstocks. Blending is excluded.
(3) Crude unit utilization is calculated as crude oil unit throughput divided by operable capacity. Prior periods have been re-presented to align with this calculation.
(4) The Superior Refinery's operable capacity is included in the metrics effective April 1, 2023. The Toledo Refinery includes a weighted average operable capacity in the metrics, as full ownership of the Toledo Refinery was acquired on February 28, 2023.
(5) Includes diesel and jet fuel.
(6) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(7) Weighted average crack spread, net of RINs is calculated as Cenovus's operable capacity-weighted average of the Chicago and Group 3 3-2-1 benchmark market crack spreads net of RINs. Average foreign exchange rates per period are used in conversion to Canadian dollars.
(8) The definition of Market Capture is Refining Margin divided by the weighted average crack spread, net of RINs, expressed as a percentage.

In the three months ended June 30, 2024, U.S. Refining throughput increased 126.4 thousand barrels per day and total refined product production increased 131.9 thousand barrels per day, compared with 2023. These increases primarily related to the Toledo Refinery's return to full operations in June 2023 and the continued ramp-up at the Superior Refinery in the second quarter of 2023. Other factors that impacted total throughput and total refined product production include:

- Improved crude unit reliability at our operated and non-operated refineries.
- A number of planned and unplanned outages at our operated and non-operated refineries, which partially offset the increases in throughput discussed above.

In the first half of 2024, U.S. Refining throughput increased 158.9 thousand barrels per day and refined product production increased 171.3 thousand barrels per day, from the same period in 2023. The increases were primarily due to obtaining the benefit of a full period of operations from the Toledo Acquisition, combined with the other factors discussed above. In addition, early in the year, we increased throughput and refined product production to take advantage of favourable market conditions.

Revenues, Gross Margin and Market Capture

Market crack spreads do not precisely mirror the configuration and product output of our refineries; however, they are used as a general market indicator. While market crack spreads are an indicator of margin from processing crude oil into refined products, the refining realized crack spread, which is the gross margin on a per-barrel basis, is affected by many factors. Some of these factors include the type of crude oil feedstock processed, refinery configuration and the proportion of gasoline, distillates and secondary product output, the time lag between the purchase of crude oil feedstock and the processing of that crude oil through the refineries, and the cost of feedstock. Processing less expensive crude relative to WTI creates a feedstock cost advantage. Our feedstock costs are valued on a FIFO accounting basis.

Revenues increased $1.9 billion and $3.5 billion, respectively, in the three and six months ended June 30, 2024, compared with 2023, primarily due to higher refined product production, offset by lower refined product pricing. Average benchmark gasoline and diesel prices decreased in the three and six months ended June 30, 2024, compared with the same periods in 2023.

For the three and six months ended June 30, 2024, the Chicago 3-2-1 crack spread decreased 34 percent and 37 percent, respectively, to US$18.76 per barrel and US$18.10 per barrel, respectively, from the same periods in 2023. The Group 3 crack spread decreased 43 percent and 44 percent to US$18.13 per barrel and US$17.82 per barrel, respectively, in the three and six months ended June 30, 2024, compared with 2023.

In the three and six months ended June 30, 2024, Gross Margin increased $94 million and $466 million, respectively, compared with 2023, primarily due to higher crude throughput, the benefit of processing feedstock purchased at lower prices in prior periods and the benefits from weaker RINs pricing. The increase was partially offset by lower market crack spreads and higher heavy crude feedstock costs driven by the increase in the WCS benchmark price and the narrowing of the WTI-WCS differential at Hardisty. The WTI-WCS differential at Hardisty narrowed in the three and six month periods by 10 percent and 17 percent, respectively, compared with the same periods in 2023.

Market Capture is the Refining Margin generated as a percentage of the average market crack spread, net of RINs, weighted by operable capacity, calculated on a FIFO basis of accounting. Both the Chicago and Group 3 3-2-1 market crack spreads are relevant for our refining assets. As such, Market Capture has been determined based on an operable capacity-weighted average of these benchmark market crack spreads. For the three and six months ended June 30, 2024, Market Capture was 70 percent and 90 percent, respectively (2023 – 57 percent and 66 percent, respectively).

Operating Expenses

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions, except where indicated)	**2024**	2023	**2024**	2023
Operating Expenses	**684**	679	**1,294**	1,281
Operating Expenses - Turnaround Costs	**58**	26	**92**	43
Per-Unit Operating Expenses [(1)] ($/bbl)	**12.66**	16.09	**12.17**	16.86
Per-Unit Operating Expenses - Turnaround Costs [(1)]	**1.08**	0.63	**0.87**	0.56

(1) Specified financial measure. The definition of Per-Unit Operating Expense has been revised to operating expenses divided by total processed inputs. Prior periods have been re-presented. The definition of Per-Unit Operating Expense – Turnaround Costs is operating expenses – turnaround costs divided by total processed inputs. See the Specified Financial Measures Advisory of this MD&A.

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

In the three months ended June 30, 2024, operating expenses remained relatively consistent compared with 2023, due to increases in routine operating expenses related to operations at the Toledo Refinery and higher turnaround expenses. The increases were offset by higher repairs and maintenance costs and project costs as the Toledo Refinery ramped up in the second quarter of 2023.

Turnaround expenses increased in the quarter in preparation for the turnaround at the Lima Refinery combined with a turnaround at our non-operated Borger Refinery, which was smaller in scope than the turnaround at our non-operated Wood River Refinery in 2023.

Operating expenses were relatively consistent in the six months ended June 30, 2024, compared with the same period in 2023, due to higher turnaround expenses, as discussed above, and an increase in workforce costs due to the Toledo Acquisition, offset by a decrease in repairs and maintenance expenses and project costs.

Per-unit operating expenses are calculated as operating expenses divided by total processed inputs. Per-unit operating expenses decreased in the three and six months ended June 30 2024, compared with the same periods in 2023, due to the increase in total processed inputs with the ramp-up of the Superior Refinery in the second quarter of 2023 and the Toledo Refinery returning to full operations in June 2023.

CORPORATE AND ELIMINATIONS

Financial Results

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2024**	2023	**2024**	2023
Realized (Gain) Loss on Risk Management	**—**	(4)	**3**	3
Unrealized (Gain) Loss on Risk Management	**—**	21	**30**	51
General and Administrative	**175**	167	**421**	325
Finance Costs, Net [(1)]	**141**	159	**276**	320
Integration, Transaction and Other Costs	**39**	17	**72**	37
Foreign Exchange (Gain) Loss, Net	**55**	(119)	**154**	(126)
(Gain) Loss on Divestiture of Assets [(1)]	**1**	(10)	**(104)**	22
Re-measurement of Contingent Payments	**2**	(1)	**30**	16
Other (Income) Loss, Net	**(40)**	(14)	**(130)**	(20)

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

General and Administrative

Primary drivers of our general and administrative expenses in the first half of 2024 were workforce costs and information technology costs. General and administrative expenses increased in the three and six months ended June 30, 2024, compared with 2023, primarily due to non-cash stock-based compensation costs of $34 million and $135 million, respectively (2023 – $29 million and $45 million, respectively).

Finance Costs, Net

Finance costs were lower in the three and six months ended June 30, 2024, compared with the same periods in 2023, due to lower interest expense as a result of the Company's lower long-term debt. 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 six months ended June 30, 2024, was 4.49 percent and 4.48 percent, respectively (2023 – 4.70 and 4.72 percent, respectively).

Integration, Transaction and Other Costs

In the three and six months ended June 30, 2024, we incurred costs of $39 million and $72 million, respectively, largely related to modernizing and replacing certain information technology systems, optimizing business processes and standardizing data across the Company.

In the three and six months ended June 30, 2023, we incurred integration and transaction costs of $17 million and $37 million, respectively, related to the Toledo Acquisition.

Foreign Exchange (Gain) Loss, Net

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2024**	2023	**2024**	2023
Unrealized Foreign Exchange (Gain) Loss	**85**	(172)	**209**	(158)
Realized Foreign Exchange (Gain) Loss	**(30)**	53	**(55)**	32
	55	(119)	**154**	(126)

Unrealized foreign exchange losses were mainly related to the translation of U.S. denominated debt caused by a weaker Canadian dollar. Realized foreign exchange gains were primarily related to working capital.

(Gain) Loss on Divestiture of Assets

For the six months ended June 30, 2024, we recorded gains on asset divestitures of $104 million (2023 – loss of $22 million). On February 6, 2024, we closed a transaction with Athabasca Oil Corporation to create Duvernay Energy Corporation, in which we hold a 30 percent interest, and recorded a before-tax gain of $65 million on the transaction. On March 6, 2024, we closed the sale of certain Clearwater assets in our Conventional segment for net proceeds of $19 million and recorded a before-tax gain of $36 million.

Re-measurement of Contingent Payments

In connection with the acquisition of the remaining 50 percent interest in the Sunrise Oil Sands Partnership from bp Canada Energy Group ULC ("bp Canada") on August 31, 2022, Cenovus agreed to make quarterly variable payments to bp Canada for up to eight quarters subsequent to August 31, 2022, if the average WCS crude oil price in a quarter exceeds $52.00 per barrel. The maximum cumulative variable payment is $600 million. Refer to Note 13 of the interim Consolidated Financial Statements for further details.

The variable payment is accounted for as a financial option with changes in fair value recognized in net earnings (loss). As at June 30, 2024, the fair value of the remaining variable payment was estimated to be $40 million, resulting in non-cash re-measurement losses in the three and six months ended June 30, 2024, of $2 million and $30 million, respectively (2023 – gains of $1 million and losses of $16 million, respectively).

For the six months ended June 30, 2024, we paid $157 million for the quarters ended November 30, 2023, and February 29, 2024 (2023 – $134 million). The payment of $104 million for the quarter ended May 31, 2024, was made on July 30, 2024. The payments are recognized in cash from (used in) investing activities. As at June 30, 2024, the average estimated WCS forward pricing for the remaining term of the variable payment was $91.87 per barrel. The maximum payment over the remaining term of the contract is $40 million.

Other (Income) Loss, Net

For the six months ended June 30, 2024, other income was primarily related to the receipt of business interruption insurance proceeds for the Toledo Refinery.

Income Taxes

($ millions)	Three Months Ended June 30, 2024	2023	Six Months Ended June 30, 2024	2023
Current Tax				
Canada	**300**	199	**646**	457
United States	**(9)**	(17)	**2**	—
Asia Pacific	**56**	38	**100**	84
Other International	**8**	6	**17**	12
Total Current Tax Expense (Recovery)	**355**	226	**765**	553
Deferred Tax Expense (Recovery)	**(46)**	(44)	**(78)**	(414)
	309	182	**687**	139

For the six months ended June 30, 2024, we recorded current tax expense related to operations in all jurisdictions in which we operate. The increase in current tax expense was due to higher earnings compared with the same period in 2023. The effective tax rate in the first six months of 2024 was 24.0 percent (2023 – 8.5 percent). The lower effective tax rate in the first half of 2023 reflects the impact of the step-up in the tax basis on the Toledo Acquisition.

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

Our effective tax rate is a function of the relationship between total tax expense (recovery) and the amount of earnings (loss) before income taxes. The effective tax rate differs from the statutory tax rate for many reasons, including but not limited to, different tax rates between jurisdictions, non-taxable foreign exchange (gains) losses, adjustments for changes in tax rates and other legislation.

LIQUIDITY AND CAPITAL RESOURCES

Our capital allocation framework enables us to strengthen our balance sheet, provide flexibility in both high and low commodity price environments, and deliver value to shareholders. The framework enables a shift to pay out a higher percentage of Excess Free Funds Flow to common shareholders, with lower leverage and a lower risk profile.

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

($ millions)	Three Months Ended June 30, 2024	2023	Six Months Ended June 30, 2024	2023
Cash From (Used In)				
Operating Activities	**2,807**	1,990	**4,732**	1,704
Investing Activities	**(1,170)**	(1,159)	**(2,305)**	(2,914)
Net Cash Provided (Used) Before Financing Activities	**1,637**	831	**2,427**	(1,210)
Financing Activities	**(912)**	(639)	**(1,589)**	(1,074)
Effect of Foreign Exchange on Cash and Cash Equivalents	**29**	(74)	**89**	(73)
Increase (Decrease) in Cash and Cash Equivalents	**754**	118	**927**	(2,357)

As at ($ millions)	June 30, 2024	December 31, 2023
Cash and Cash Equivalents	**3,154**	2,227
Total Debt	**7,412**	7,287

Cash From (Used in) Operating Activities

For the three months ended June 30, 2024, cash from operating activities was $2.8 billion, compared with $2.0 billion in the same period in 2023. The increase was primarily due to higher Operating Margin combined with changes in non-cash working capital. Changes in non-cash working capital increased cash from operating activities by $494 million in the quarter, primarily due to higher accounts payable, partially offset by higher inventory.

For the six months ended June 30, 2024, cash from operating activities was $4.7 billion, compared with $1.7 billion in the same period in 2023. The increase was primarily due to changes in non-cash working capital and higher Operating Margin. In the first half of 2023, changes in non-cash working capital decreased cash from operating activities by $1.5 billion, primarily driven by an income tax payment of $1.2 billion, that occurred during the period.

Cash From (Used in) Investing Activities

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

Cash used in investing activities decreased in the first half of 2024 compared with 2023, due to the Toledo Acquisition in the first quarter of 2023.

Cash From (Used in) Financing Activities

Cash used in financing activities increased in the three and six months ended June 30, 2024, compared with the same periods in 2023. The increases were primarily due to cash returns to common shareholders of $1.0 billion and $1.5 billion, compared with $575 million and $815 million, respectively, in the same periods of 2023.

Working Capital

Excluding the current portion of the contingent payments, our adjusted working capital at June 30, 2024, was $4.7 billion (December 31, 2023 – $3.7 billion). The increase in working capital was driven by an increase in cash, accounts receivable and inventory, partially offset by an increase in accounts payable. The increases were primarily driven by higher crude oil prices.

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

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

Adjusted Funds Flow is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations. Free Funds Flow is a non-GAAP financial measure used to assist in measuring the available funds Cenovus has after financing its capital programs. Excess Free Funds Flow is a non-GAAP financial measure used by the Company to deliver shareholder returns and allocate capital according to our capital allocation framework.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2024**	2023	**2024**	2023
Cash From (Used in) Operating Activities	**2,807**	1,990	**4,732**	1,704
(Add) Deduct:				
Settlement of Decommissioning Liabilities	**(48)**	(41)	**(96)**	(89)
Net Change in Non-Cash Working Capital	**494**	132	**225**	(1,501)
Adjusted Funds Flow	**2,361**	1,899	**4,603**	3,294
Capital Investment	**1,155**	1,002	**2,191**	2,103
Free Funds Flow	**1,206**	897	**2,412**	1,191
Add (Deduct):				
Base Dividends Paid on Common Shares	**(334)**	(265)		
Dividends Paid on Preferred Shares	**(9)**	(9)		
Settlement of Decommissioning Liabilities	**(48)**	(41)		
Principal Repayment of Leases	**(75)**	(76)		
Acquisitions, Net of Cash Acquired	**(5)**	(4)		
Proceeds From Divestitures	**—**	3		
Excess Free Funds Flow	**735**	505		

Returns to Shareholders Target

Maintaining a strong balance sheet with the resilience to withstand price volatility and capitalize on opportunities throughout the commodity price cycle is a key element of Cenovus's capital allocation framework. We have set an ultimate Net Debt target of $4.0 billion. Our $4.0 billion Net Debt target represents a Net Debt to Adjusted Funds Flow ratio target of approximately 1.0 times at the bottom of the commodity pricing cycle, which we believe is approximately US$45.00 per barrel.

Our shareholder return framework is to deliver incremental value to shareholders through share buybacks and/or variable dividends as follows:

- When Net Debt is above $9.0 billion at quarter-end, we target to allocate 100 percent of the following quarter's Excess Free Funds Flow to deleveraging the balance sheet.
- When Net Debt is less than $9.0 billion and above $4.0 billion at quarter-end, we target to allocate 50 percent of the following quarter's Excess Free Funds Flow to shareholder returns, while continuing to deleverage the balance sheet until we achieve the Net Debt target.
- When we achieve our Net Debt target, to increase clarity and predictability of returns to shareholders, we will target to allocate 100 percent of each subsequent quarter's Excess Free Funds Flow to shareholder returns through share buybacks and/or variable dividends, reduced by the amount Net Debt exceeds $4.0 billion at the applicable previous quarter's end.

In order to efficiently manage working capital and cash, the allocation of Excess Free Funds Flow to shareholder returns in any of the scenarios described above may be accelerated, deferred or reallocated between quarters, while maintaining our target to, over time, allocate 100 percent of Excess Free Funds Flow to shareholder returns and sustain Net Debt at $4.0 billion.

As at March 31, 2024, our long-term debt was $7.2 billion, and our Net Debt position was $4.8 billion. Therefore, our returns to shareholders target for the three months ended June 30, 2024, was 50 percent of the current quarter's Excess Free Funds Flow of $735 million. Our target return was $368 million, which was exceeded through share buybacks of $440 million.

	Three Months Ended	
($ millions)	**June 30, 2024**	March 31, 2024
Excess Free Funds Flow	**735**	832
Target Return	**368**	416
Purchase of Common Shares Under NCIB	**(440)**	(165)
Amount Available for Variable Dividend	**—**	251

As at June 30, 2024, our Net Debt position was $4.3 billion and in July, we achieved our Net Debt target of $4.0 billion. Therefore, in the third quarter of 2024, we will target to allocate 100 percent of Excess Free Funds Flow to shareholder returns through share buybacks and/or variable dividends, adjusted for the amount Net Debt exceeded $4.0 billion at the previous quarter end, which was $258 million as at June 30, 2024. As previously noted, we may accelerate, defer or reallocate any quarter's allocation of Excess Free Funds Flow to effectively manage working capital and cash.

Short-Term Borrowings

As at June 30, 2024, the Company's proportionate share drawn on the WRB uncommitted demand facilities was US$100 million (C$137 million) (December 31, 2023 – US$135 million (C$179 million)). There were no direct borrowings on our uncommitted demand facilities as at June 30, 2024, or as at December 31, 2023.

Long-Term Debt, Including Current Portion

Long-term debt, including the current portion, as at June 30, 2024, was $7.3 billion (December 31, 2023 – $7.1 billion). This includes U.S. dollar denominated unsecured notes of US$3.8 billion, or C$5.2 billion (December 31, 2023 – US$3.8 billion, or C$5.0 billion) and Canadian dollar denominated unsecured notes of $2.0 billion (December 31, 2023 – $2.0 billion).

As at June 30, 2024, we were in compliance with all of the terms of our debt agreements.

Available Sources of Liquidity

The following sources of liquidity are available as at June 30, 2024:

($ millions)	Maturity	Amount Available
Cash and Cash Equivalents	**n/a**	**3,154**
Committed Credit Facility (1)		
Revolving Credit Facility – Tranche A	**June 26, 2028**	**3,300**
Revolving Credit Facility – Tranche B	**June 26, 2027**	**2,200**
Uncommitted Demand Facilities		
Cenovus Energy Inc. (2)	**n/a**	**1,116**
WRB (3)	**n/a**	**171**

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

(2) Represents amounts available for cash draws. Our uncommitted demand facilities include $1.7 billion, of which $1.4 billion may be drawn for general purposes, or the full amount can be available to issue letters of credit. As at June 30, 2024, there were outstanding letters of credit aggregating to $319 million (December 31, 2023 – $364 million) and no direct borrowings (December 31, 2023 – $nil).

(3) Represents Cenovus's proportionate share of US$225 million available to cover short-term working capital requirements. As at June 30, 2024, US$100 million (C$137 million) of this capacity was drawn (December 31, 2023 – US$135 million (C$179 million)).

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

Under the terms of our committed credit facility, we are required to maintain a debt to capitalization ratio, as defined in the debt agreements, not to exceed 65 percent. We are below this limit.

Base Shelf Prospectus

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

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, Total Debt, the Net Debt to Adjusted EBITDA ratio, Net Debt to Adjusted Funds Flow ratio and 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	June 30, 2024	December 31, 2023
Net Debt to Adjusted EBITDA Ratio (times)	**0.4**	0.5
Net Debt to Adjusted Funds Flow Ratio (times)	**0.4**	0.6
Net Debt to Capitalization Ratio (percent)	**12**	15

Our Net Debt to Adjusted Funds Flow ratio and our Net Debt to Adjusted EBITDA ratio targets are approximately 1.0 times at the bottom of the commodity price cycle, which we believe is approximately US$45.00 per barrel WTI. This ratio may fluctuate periodically outside the range due to factors such as persistently high or low commodity prices. Our objective is to maintain a high level of capital discipline and manage our capital structure to help ensure we have sufficient liquidity through all stages of the economic cycle. To ensure financial resilience, we may, among other actions, adjust capital and operating spending, draw down on our credit facilities or repay existing debt, adjust dividends paid to shareholders, purchase our common shares for cancellation, issue new debt, or issue new shares.

Our Net Debt to Adjusted Funds Flow ratio and Net Debt to Adjusted EBITDA ratio as at June 30, 2024, decreased compared with December 31, 2023, as a result of lower Net Debt and higher Operating Margin. See the Operating and Financial Results section of this MD&A for more information on Operating Margin and Net Debt.

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

Share Capital and Stock-Based Compensation Plans

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

As at June 30, 2024, there were approximately 1,856.6 million common shares outstanding (December 31, 2023 – 1,871.9 million common shares) and 36 million preferred shares outstanding (December 31, 2023 – 36 million preferred shares). Refer to Note 16 of the interim Consolidated Financial Statements for further details.

As at June 30, 2024, there were approximately 5.0 million Cenovus Warrants outstanding (December 31, 2023 – 7.6 million Cenovus Warrants). Each Cenovus Warrant entitles the holder to acquire one common share for a period of five years from the date of issue at an exercise price of $6.54 per common share. The Cenovus Warrants expire on January 1, 2026. Refer to Note 16 of the interim Consolidated Financial Statements for further details.

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

As at July 29, 2024	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares	**1,856,102**	**n/a**
Cenovus Warrants	**4,985**	**n/a**
Series 1 First Preferred Shares	**10,740**	**n/a**
Series 2 First Preferred Shares	**1,260**	**n/a**
Series 3 First Preferred Shares	**10,000**	**n/a**
Series 5 First Preferred Shares	**8,000**	**n/a**
Series 7 First Preferred Shares	**6,000**	**n/a**
Stock Options	**9,358**	**5,050**
Other Stock-Based Compensation Plans	**17,446**	**1,712**

Common Share Dividends

In the second quarter of 2024, we paid base dividends of $334 million or $0.180 per common share (2023 – $265 million or $0.140 per common share). In the first six months of 2024, we paid base dividends of $596 million or $0.320 per common share (2023 – $465 million or $0.245 per common share).

On July 31, 2024, the Board of Directors declared a third quarter base dividend of $0.180 per common share. The dividend is payable on September 27, 2024, to common shareholders of record as at September 13, 2024.

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

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

Cumulative Redeemable Preferred Share Dividends

For the three and six months ended June 30, 2024, dividends of $9 million and $18 million, respectively, were paid on the series 1, 2, 3, 5 and 7 preferred shares (2023 – $9 million and $27 million, respectively). On July 31, 2024, the Board declared a third quarter dividend on the series 1, 2, 3, 5 and 7 preferred shares for a total of $9 million, payable on October 1, 2024, to preferred shareholders of record as at September 13, 2024.

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

Share Repurchases

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2024	2023	**2024**	2023
Common Shares Purchased and Cancelled Under NCIB (millions of common shares)	**15.4**	14.0	**22.8**	15.6
Weighted Average Price per Common Share ($)	**27.88**	22.08	**26.07**	22.43
Purchase of Common Shares Under NCIB ($ millions)	**(440)**	(310)	**(605)**	(350)

From July 1, 2024, to July 29, 2024, the Company purchased an additional 656 thousand common shares for $18 million. As at July 29, 2024, the Company can further purchase up to 99.2 million common shares under the NCIB.

Contractual Obligations and Commitments

We have obligations for goods and services entered into in the normal course of business. Obligations that have original maturities of less than one year are excluded from our total commitments disclosed below. For further information, see Note 23 to the interim Consolidated Financial Statements.

Our total commitments were $28.3 billion as at June 30, 2024 (December 31, 2023 – $28.8 billion), of which $24.9 billion are for various transportation and storage commitments and $225 million are for product purchase commitments. Transportation commitments include $683 million that are subject to regulatory approval or were approved, but are not yet in service. Terms are up to 20 years on commencement, and should help align with the Company's future transportation requirements.

As at June 30, 2024, our total commitments included commitments with HMLP of $2.0 billion related to long-term transportation and storage commitments.

As at June 30, 2024, outstanding letters of credit issued as security for performance under certain contracts totaled $319 million (December 31, 2023 – $364 million).

Legal Proceedings

We are involved in a limited number of legal claims associated with the normal course of operations. We believe that any liabilities that might arise from such matters, to the extent not provided for, are not likely to have a material effect on our interim Consolidated Financial Statements.

Transactions with Related Parties

Cenovus holds a 40 percent interest in the jointly controlled entity HCML. The Company's share of equity investment income (loss) related to the joint venture are recorded in (income) loss from equity-accounted affiliates.

For the six months ended June 30, 2024, the Company received $53 million of distributions from HCML (2023 – $38 million) and paid $nil in contributions (2023 – $24 million).

Cenovus holds a 35 percent interest in HMLP. As the operator of the assets held by HMLP, we provide management services for which we recover shared service costs in accordance with our profit sharing agreement. We are also the contractor for HMLP and construct its assets on a cost recovery basis with certain restrictions. For the six months ended June 30, 2024, we charged HMLP $69 million for construction and management services (2023 – $63 million).

We pay an access fee to HMLP for the use of its pipeline systems that are used by our blending business. We also pay HMLP for transportation and storage services. Payments for access fees and transportation and storage services are made based on rates contractually agreed to with HMLP. For the six months ended June 30, 2024, we incurred costs of $140 million for the use of HMLP's pipeline systems, as well as for transportation and storage services (2023 – $138 million).

RISK MANAGEMENT AND RISK FACTORS

For a full understanding of the risks that impact us, the following discussion should be read in conjunction with the Risk Management and Risk Factors section of our 2023 annual MD&A.

We are exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the energy industry as a whole and others are unique to our operations. The impact of any risk or a combination of risks may adversely affect, among other things, our business, reputation, financial condition, results of operations and cash flows, which may, without limitation, reduce or restrict our ability to pursue our strategic priorities, meet our targets or outlooks, goals, initiatives and ambitions, respond to changes in our operating environment, repurchase our shares, pay dividends to our shareholders and fulfill our obligations (including debt servicing requirements) and/or may materially affect the market price of our securities.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATION UNCERTAINTIES AND ACCOUNTING POLICIES

Management is required to make estimates and assumptions, as well as use judgment in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our material accounting policies are reviewed annually by the Audit Committee of the Board. Further details on the basis of preparation and our material accounting policies can be found in the notes to the Consolidated Financial Statements for the year ended December 31, 2023.

Critical Judgments in Applying Accounting Policies and Key Sources of Estimation Uncertainty

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in our annual and interim Consolidated Financial Statements. A full list of the critical judgments used in applying accounting policies and key sources of estimation uncertainty can be found in the notes to the Consolidated Financial Statements for the year ended December 31, 2023.

Update to Accounting Policies

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

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

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

New Accounting Standards and Interpretations Not Yet Adopted

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

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

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

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at June 30, 2024. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of ICFR. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at June 30, 2024.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

ADVISORY

Oil and Gas Information

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

Forward-looking Information

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

This forward-looking information is identified by words such as "aim", "anticipate", "believe", "commit", "continue", "could", "estimate", "expect", "focus", "may", "objective", "opportunities", "plan", "position", "priority", "progress", "strive", "target", and "will", or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: our five strategic objectives; shareholder value and returns; safety; sustainability; our commitment to the Pathways Alliance foundational project; maximizing value; financial discipline; disciplined capital allocation; Free Funds Flow; cash flow volatility and stability; managing our balance sheet; liquidity; growth of our base business; capital investment; our 2024 corporate guidance; reducing costs; realizing the full value of our integrated business; reinvesting in our business; diversifying our portfolio; capitalizing on opportunities; Net Debt; allocating Excess Free Funds Flow; project execution; reliable operations; being best in class operators; maintaining a strong balance sheet; costs; margins; realizing the full value of our integrated business; long term-value for Cenovus; downstream reliability and profitability; in respect of the White Rose project, returning the SeaRose FPSO to the field, resuming production and achieving first oil; ramping up TMX; our five ESG focus areas; variable payments; provision for income taxes; funding near-term cash requirements; credit ratings; meeting payment obligations; cash flow volatility and stability; Net Debt to Adjusted Funds Flow ratio; the Company's capital allocation framework; capitalizing on opportunities throughout the commodity price cycle; Net Debt to Adjusted EBITDA ratio; maintaining sufficient liquidity; financial resilience; liabilities from legal proceedings; transportation and storage commitments; and the Company's outlook for commodities and the Canadian dollar and the influences and effects on Cenovus.

Readers are cautioned not to place undue reliance on forward-looking information as the Company's actual results may differ materially from those expressed or implied. Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to the Company and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include, but are not limited to: forecast bitumen, crude oil and natural gas, natural gas liquids, condensate and refined products prices, light-heavy crude oil price differentials; the Company's ability to realize the anticipated benefits and anticipated cost synergies of acquisitions; the accuracy of any assessments undertaken in connection with acquisitions; forecast production and crude throughput volumes and timing thereof; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; the absence of significant adverse changes to government policies, legislation and regulations (including related to climate change), Indigenous relations, interest rates, inflation, foreign exchange rates, competitive conditions and the supply and demand for bitumen, crude oil and natural gas, NGLs, condensate and refined products; the political, economic and social stability of jurisdictions in which the Company operates; the absence of significant disruption of operations, including as a result of harsh weather, natural disaster, accident, civil unrest or other similar events; the prevailing climatic conditions in the Company's operating locations; achievement of further cost reductions and sustainability thereof; applicable royalty regimes, including expected royalty rates; future improvements in availability of product transportation capacity; increase to the Company's share price and market capitalization over the long term; opportunities to purchase shares for cancellation at prices acceptable to the Company; the sufficiency of cash balances, internally generated cash flows, existing credit facilities, management of the Company's asset portfolio and access to capital and insurance coverage to pursue and fund future investments, sustainability and development plans and dividends, including any increase thereto; production from the Company's Conventional segment providing an economic hedge for the natural gas required as a fuel source at both the Company's oil sands and refining operations; realization of expected capacity to store within the Company's oil sands reservoirs barrels not yet produced, including that the Company will be able to time production and sales of our inventory at later dates when demand has increased, pipeline and/or storage capacity has improved and future crude oil differentials have narrowed; the WTI-WCS differential in Alberta remains largely tied to global supply factors and heavy crude processing capacity; the ability of the Company's refining capacity, dynamic storage, existing pipeline commitments, crude-by-rail loading capacity and financial hedge transactions to partially mitigate a portion of the Company's WCS crude oil volumes against wider differentials; the Company's ability to produce from oil sands facilities on an unconstrained basis; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; the accuracy of accounting estimates and judgments; the Company's ability to obtain necessary regulatory and partner approvals; the successful, timely and cost effective implementation of capital projects, development projects or stages thereof; the Company's ability to meet current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; the Company's ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; the Company's ability to complete acquisitions and divestitures, including with desired transaction metrics and within expected timelines; the accuracy of climate scenarios and assumptions, including third party data on which the Company relies; ability to access and implement all technology and equipment necessary to achieve expected future results, including in respect of climate and GHG emissions targets and ambitions and the commercial viability and scalability of emission reduction strategies and related technology and products; collaboration with the government, Pathways Alliance and other industry organizations; alignment of realized WCS and WCS prices used to calculate the variable payment to bp Canada; market and business conditions; forecast inflation and other assumptions inherent in the Company's 2024 guidance available on cenovus.com and as set out below; the availability of Indigenous owned or operated businesses and the Company's ability to retain them; and other risks and uncertainties described from time to time in the filings the Company makes with securities regulatory authorities.

2024 guidance dated July 31, 2024, and available on cenovus.com, assumes: Brent prices of US$83.50 per barrel, WTI prices of US$79.00 per barrel; WCS of US$63.00 per barrel; Differential WTI-WCS of US$15.90 per barrel; AECO natural gas prices of $1.65 per Mcf; Chicago 3-2-1 crack spread of US$17.40 per barrel; and an exchange rate of $0.73 US$/C$.

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

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

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

ABBREVIATIONS AND DEFINITIONS

Abbreviations

The following abbreviations and definitions are used in this document:

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

Revision of Operational Metrics

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

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

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

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

Definitions and reconciliations of certain Specified Financial Measures, such as Refining Margin, Market Capture, Per-Unit Operating Expenses and Per-Unit Operating Expenses – Turnaround Costs are included in the Specified Financial Measures section of this MD&A.

SPECIFIED FINANCIAL MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS Accounting Standards including Operating Margin, Operating Margin by asset, Adjusted Funds Flow, Adjusted Funds Flow Per Share – Basic, Adjusted Funds Flow Per Share – Diluted, Free Funds Flow, Excess Free Funds Flow, Gross Margin, Refining Margin, Market Capture, Realized Sales Price and Netbacks (including the total Netback per BOE).

These measures may not be comparable to similar measures presented by other issuers. These measures are described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation, or as a substitute for, measures prepared in accordance with IFRS Accounting Standards. The definition and reconciliation, if applicable, of each specified financial measure is presented in this Advisory and may also be presented in the Operating and Financial Results or Liquidity and Capital Resources sections of this MD&A. Refer to the Specified Financial Measures Advisory of the relevant period's MD&A for reconciliations of Operating Margin, Adjusted Funds Flow, Free Funds Flow, Excess Free Funds Flow, Realized Sales Price and Netbacks for prior period information from 2024 and 2023 that is not found below.

Operating Margin

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

Operating Margin

	Three Months Ended June 30,					
	2024	2023	**2024**	2023	**2024**	2023
($ millions)	**Upstream** (1)		**Downstream** (1)		**Total**	
Gross Sales (2)						
External Sales	**6,791**	5,658	**8,953**	7,210	**15,744**	12,868
Intersegment Sales	**1,924**	1,627	**100**	217	**2,024**	1,844
	8,715	7,285	**9,053**	7,427	**17,768**	14,712
Royalties	**(859)**	(637)	**—**	—	**(859)**	(637)
Revenues	**7,856**	6,648	**9,053**	7,427	**16,909**	14,075
Expenses						
Purchased Product (2)	**815**	751	**8,099**	6,447	**8,914**	7,198
Transportation and Blending (2)	**3,043**	2,770	**—**	—	**3,043**	2,770
Operating	**889**	883	**1,099**	843	**1,988**	1,726
Realized (Gain) Loss on Risk Management	**20**	(13)	**8**	(6)	**28**	(19)
Operating Margin	**3,089**	2,257	**(153)**	143	**2,936**	2,400

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Comparative periods reflect certain revisions. See Note 24 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

	Six Months Ended June 30,					
	2024	2023	**2024**	2023	**2024**	2023
($ millions)	**Upstream** [1]		**Downstream** [1]		**Total**	
Gross Sales [2]						
External Sales	**12,538**	11,585	**17,350**	14,141	**29,888**	25,726
Intersegment Sales	**4,041**	2,917	**270**	423	**4,311**	3,340
	16,579	14,502	**17,620**	14,564	**34,199**	29,066
Royalties	**(1,606)**	(1,233)	**—**	—	**(1,606)**	(1,233)
Revenues	**14,973**	13,269	**17,620**	14,564	**32,593**	27,833
Expenses						
Purchased Product [2]	**1,586**	1,589	**15,318**	12,438	**16,904**	14,027
Transportation and Blending [2]	**5,854**	5,797	**—**	—	**5,854**	5,797
Operating	**1,787**	1,912	**1,886**	1,597	**3,673**	3,509
Realized (Gain) Loss on Risk Management	**26**	3	**9**	(5)	**35**	(2)
Operating Margin	**5,720**	3,968	**407**	534	**6,127**	4,502

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Comparative periods reflect certain revisions. See Note 24 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Operating Margin by Asset

	Three Months Ended June 30, 2024			Six Months Ended June 30, 2024		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore** [1]	**Atlantic**	**Asia Pacific**	**Offshore** [1]
Gross Sales	**151**	**320**	**471**	**193**	**635**	**828**
Royalties	**1**	**(24)**	**(23)**	**(1)**	**(48)**	**(49)**
Revenues	**152**	**296**	**448**	**192**	**587**	**779**
Expenses						
Transportation and Blending	**7**	**—**	**7**	**7**	**—**	**7**
Operating	**110**	**32**	**142**	**167**	**60**	**227**
Operating Margin	**35**	**264**	**299**	**18**	**527**	**545**

	Three Months Ended June 30, 2023			Six Months Ended June 30, 2023		
($ millions)	Atlantic	Asia Pacific	Offshore [1]	Atlantic	Asia Pacific	Offshore [1]
Gross Sales	5	223	228	154	547	701
Royalties	(1)	(12)	(13)	(9)	(30)	(39)
Revenues	4	211	215	145	517	662
Expenses						
Transportation and Blending	4	—	4	9	—	9
Operating	26	37	63	143	62	205
Operating Margin	(26)	174	148	(7)	455	448

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

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

Adjusted Funds Flow is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations, in total and on a per-share basis. Adjusted Funds Flow is defined as cash from (used in) operating activities excluding settlement of decommissioning liabilities and net change in operating non-cash working capital. Operating non-cash working capital is composed of accounts receivable and accrued revenues, income tax receivable, inventories (excluding non-cash inventory write-downs and reversals), accounts payable and accrued liabilities, and income tax payable. Adjusted Funds Flow Per Share – Basic is defined as Adjusted Funds Flow divided by the basic weighted average number of shares. Adjusted Funds Flow Per Share – Diluted is defined as Adjusted Funds Flow divided by the diluted weighted average number of shares.

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

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

Gross Margin, Refining Margin and Market Capture

Gross Margin is a non-GAAP financial measure and Refining Margin contains a non-GAAP financial measure. These measures are used to evaluate the performance of our downstream operations. We define Gross Margin as revenues less purchased product. We define Refining Margin as Gross Margin from our refineries and Upgrader divided by total processed inputs. Total processed inputs was updated as the denominator to better reflect the overall inputs required to produce refined products. The comparative periods were previously calculated based on barrels of crude oil unit throughput and have been revised to conform with our current presentation.

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

Canadian Refining

	Three Months Ended June 30, 2024		
($ millions)	**Lloydminster Upgrader and Lloydminster Refinery Total**	**Other** [1]	**Total Canadian Refining** [2]
Revenues	**1,065**	**70**	**1,135**
Purchased Product	**930**	**45**	**975**
Gross Margin	**135**	**25**	**160**
Total Processed Inputs (Mbbls/d)	**58.9**		
Refining Margin ($/bbl)	**25.21**		

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

	Three Months Ended June 30, 2023		
($ millions)	Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Refining [2]
Revenues	1,267	96	1,363
Purchased Product	1,019	64	1,083
Gross Margin	248	32	280
Total Processed Inputs (Mbbls/d)	102.7		
Refining Margin ($/bbl)	26.54		

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

	Six Months Ended June 30, 2024		
($ millions)	**Lloydminster Upgrader and Lloydminster Refinery Total**	**Other** [1]	**Total Canadian Refining** [2]
Revenues	**2,314**	**153**	**2,467**
Purchased Product	**1,954**	**108**	**2,062**
Gross Margin	**360**	**45**	**405**
Total Processed Inputs (Mbbls/d)	**83.8**		
Refining Margin ($/bbl)	**23.57**		

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

($ millions)	Six Months Ended June 30, 2023 Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Refining [2]
Revenues	2,668	203	2,871
Purchased Product	2,035	141	2,176
Gross Margin	633	62	695
Total Processed Inputs (Mbbls/d)	104.2		
Refining Margin ($/bbl)	33.56		

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

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

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

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

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

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

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

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

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

U.S. Refining

($ millions)	**Three Months Ended June 30,** **2024**	2023	**Six Months Ended June 30,** **2024**	2023
Revenues (1) (2)	**7,918**	6,064	**15,153**	11,693
Purchased Product (1) (2)	**7,124**	5,364	**13,256**	10,262
Gross Margin	**794**	700	**1,897**	1,431
Total Processed Inputs (Mbbls/d)	**594.0**	464.2	**584.5**	419.9
Refining Margin ($/bbl)	**14.69**	16.57	**17.83**	18.83
Operable Capacity (Mbbls/d)	**612.3**	612.3	**612.3**	612.3
Operable Capacity by Regional Benchmark (percent)				
Chicago 3-2-1 Crack Spread Weighting	**81**	81	**81**	80
Group 3 3-2-1 Crack Spread Weighting	**19**	19	**19**	20
Benchmark Prices and Exchange Rate				
Chicago 3-2-1 Crack Spread (US$/bbl)	**18.76**	28.57	**18.10**	28.72
Group 3 3-2-1 Crack Spread (US$/bbl)	**18.13**	31.78	**17.82**	31.56
RINs (US$/bbl)	**3.39**	7.72	**3.53**	7.98
US$ per C$1 - Average	**0.731**	0.745	**0.736**	0.742
Weighted Average Crack Spread, Net of RINs ($/bbl)	**20.86**	28.82	**19.72**	28.72
Market Capture (3) (percent)	**70**	57	**90**	66

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Comparative periods reflect certain revisions. See Note 24 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.
(3) The Superior Refinery's operable capacity is included in the Market Capture calculation effective April 1, 2023. For the six months ended June 30, 2023, Market Capture includes a weighted average operable capacity for the Toledo Refinery as full ownership was acquired on February 28, 2023.

($ millions)	Three Months Ended March 31, 2024	December 31, 2023	September 30, 2023	Twelve Months Ended December 31, 2023
Revenues [1]	7,235	6,847	7,853	26,393
Purchased Product [1]	6,132	6,625	6,467	23,354
Gross Margin	1,103	222	1,386	3,039
Total Processed Inputs (Mbbls/d)	575.0	500.6	576.6	479.7
Refining Margin ($/bbl)	21.08	4.82	26.13	17.36
Operable Capacity (Mbbls/d)	612.3	612.3	612.3	612.3
Operable Capacity by Regional Benchmark (percent)				
Chicago 3-2-1 Crack Spread Weighting	81	81	81	82
Group 3 3-2-1 Crack Spread Weighting	19	19	19	18
Benchmark Prices and Exchange Rate				
Chicago 3-2-1 Crack Spread (US$/bbl)	17.45	13.24	26.06	24.19
Group 3 3-2-1 Crack Spread (US$/bbl)	17.50	18.55	36.96	29.66
RINs (US$/bbl)	3.68	4.77	7.42	7.04
US$ per C$1 - Average	0.741	0.734	0.746	0.741
Weighted Average Crack Spread, Net of RINs ($/bbl)	18.59	12.94	27.81	24.49
Market Capture [2] (percent)	113	37	94	71

(1) Comparative periods reflect certain revisions. See Note 24 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

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

Per-Unit Operating Expenses and Turnaround Costs

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

Per-Unit Operating Expenses – Turnaround Costs are specified financial measures used to evaluate the cost of turnarounds for our downstream operations. We define Per-Unit Operating Expenses – Turnaround Costs as turnaround expenses from the refining segments' operating expenses divided by total processed inputs.

Our Upstream Per-Unit Operating Expenses are defined as total operating expenses divided by sales volumes, and are part of our Netback calculation, which can be found below.

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.

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 below.

Netback Reconciliations and Realized Sales Price

Netback is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring operating performance. Our Netback calculation is substantially aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook. Netback is defined as gross sales less royalties, transportation and blending, and operating expenses. Netbacks do not reflect non-cash write-downs or reversals of product inventory until it is realized when the product is sold and exclude risk management activities. Condensate or butane (diluent) is blended with crude oil to transport it to market. In the three months ended March 31, 2024, modifications were made to our netback definition to enhance the clarity of certain costs captured in this metric. These modifications resulted in minor adjustments that are captured in the netback calculation on a prospective basis.

Realized sales price contains a non-GAAP measure. It includes our gross sales, purchased diluent costs and profit from optimization activities, such as cogeneration, third-party processing and trading. Netback per barrel of oil equivalent contains a non-GAAP measure. Netbacks per BOE reflect our margin on a per-barrel of oil equivalent basis. Per-unit measures are divided by sales volumes.

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

Oil Sands

	Basis of Netback Calculation						
Three Months Ended June 30, 2024 ($ millions)	Foster Creek	Christina Lake	Sunrise	Lloydminster Oil Sands (1)	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
Gross Sales	1,533	1,686	438	1,064	**4,721**	—	**4,721**
Royalties	(271)	(401)	(25)	(111)	**(808)**	—	**(808)**
Revenues	1,262	1,285	413	953	**3,913**	—	**3,913**
Expenses							
Purchased Product	—	—	—	—	**—**	—	**—**
Transportation and Blending	248	142	87	54	**531**	—	**531**
Operating	169	168	62	211	**610**	—	**610**
Netback	845	975	264	688	**2,772**	—	**2,772**
Realized (Gain) Loss on Risk Management							**20**
Operating Margin							**2,752**

	Basis of Netback Calculation	Adjustments			
Three Months Ended June 30, 2024 ($ millions)	Total Oil Sands	Condensate	Third-party Sourced	Other (2)	Total Oil Sands (3)
Gross Sales	**4,721**	2,406	305	121	**7,553**
Royalties	**(808)**	—	—	(6)	**(814)**
Revenues	**3,913**	2,406	305	115	**6,739**
Expenses					
Purchased Product	**—**	—	305	98	**403**
Transportation and Blending	**531**	2,406	—	16	**2,953**
Operating	**610**	—	—	5	**615**
Netback	**2,772**	—	—	(4)	**2,768**
Realized (Gain) Loss on Risk Management	**20**	—	—	—	**20**
Operating Margin	**2,752**	—	—	(4)	**2,748**

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

Three Months Ended June 30, 2023 ($ millions)	Basis of Netback Calculation						
	Foster Creek	**Christina Lake**	**Sunrise**	**Lloydminster Oil Sands (1)**	**Total Bitumen and Heavy Oil**	**Natural Gas**	**Total Oil Sands**
Gross Sales	1,205	1,398	304	827	**3,734**	2	**3,736**
Royalties	(219)	(314)	(14)	(72)	**(619)**	(2)	**(621)**
Revenues	986	1,084	290	755	**3,115**	—	**3,115**
Expenses							
Purchased Product	—	—	—	—	**—**	—	**—**
Transportation and Blending	205	124	54	41	**424**	—	**424**
Operating	195	170	75	227	**667**	2	**669**
Netback	586	790	161	487	**2,024**	(2)	**2,022**
Realized (Gain) Loss on Risk Management							**(8)**
Operating Margin							**2,030**

Three Months Ended June 30, 2023 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	**Condensate**	**Third-party Sourced**	**Other (2)**	**Total Oil Sands (3)**
Gross Sales (4)	**3,736**	2,244	351	106	**6,437**
Royalties	**(621)**	—	—	1	**(620)**
Revenues	**3,115**	2,244	351	107	**5,817**
Expenses					
Purchased Product (4)	**—**	—	351	63	**414**
Transportation and Blending	**424**	2,244	—	32	**2,700**
Operating	**669**	—	—	7	**676**
Netback	**2,022**	—	—	5	**2,027**
Realized (Gain) Loss on Risk Management	**(8)**	—	—	(1)	**(9)**
Operating Margin	**2,030**	—	—	6	**2,036**

(1) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.
(2) Other includes construction, transportation and blending.
(3) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.
(4) Comparative periods reflect certain revisions. See Note 24 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Six Months Ended June 30, 2024 ($ millions)	Basis of Netback Calculation						
	Foster Creek	**Christina Lake**	**Sunrise**	**Lloydminster Oil Sands (1)**	**Total Bitumen and Heavy Oil**	**Natural Gas**	**Total Oil Sands**
Gross Sales	2,889	3,160	778	1,914	**8,741**	—	**8,741**
Royalties	(564)	(740)	(36)	(165)	**(1,505)**	—	**(1,505)**
Revenues	2,325	2,420	742	1,749	**7,236**	—	**7,236**
Expenses							
Purchased Product	—	—	—	—	**—**	—	**—**
Transportation and Blending	429	261	158	99	**947**	—	**947**
Operating	360	356	127	422	**1,265**	—	**1,265**
Netback	1,536	1,803	457	1,228	**5,024**	—	**5,024**
Realized (Gain) Loss on Risk Management							**33**
Operating Margin							**4,991**

Six Months Ended June 30, 2024 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	**Condensate**	**Third-party Sourced**	**Other (2)**	**Total Oil Sands (3)**
Gross Sales	**8,741**	4,711	518	211	**14,181**
Royalties	**(1,505)**	—	—	(6)	**(1,511)**
Revenues	**7,236**	4,711	518	205	**12,670**
Expenses					
Purchased Product	**—**	—	518	174	**692**
Transportation and Blending	**947**	4,711	—	28	**5,686**
Operating	**1,265**	—	—	10	**1,275**
Netback	**5,024**	—	—	(7)	**5,017**
Realized (Gain) Loss on Risk Management	**33**	—	—	—	**33**
Operating Margin	**4,991**	—	—	(7)	**4,984**

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

Six Months Ended June 30, 2023 ($ millions)	Foster Creek	Christina Lake	Sunrise	Lloydminster Oil Sands (1)	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
	Basis of Netback Calculation						
Gross Sales	2,237	2,465	485	1,432	**6,619**	5	**6,624**
Royalties	(408)	(587)	(20)	(119)	**(1,134)**	(3)	**(1,137)**
Revenues	1,829	1,878	465	1,313	**5,485**	2	**5,487**
Expenses							
Purchased Product	—	—	—	—	**—**	—	**—**
Transportation and Blending	427	289	99	79	**894**	—	**894**
Operating	410	365	154	463	**1,392**	6	**1,398**
Netback	992	1,224	212	771	**3,199**	(4)	**3,195**
Realized (Gain) Loss on Risk Management							**(1)**
Operating Margin							**3,196**

Six Months Ended June 30, 2023 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced	Other (2)	Total Oil Sands (3)
Gross Sales (4)	**6,624**	4,689	645	186	**12,144**
Royalties	**(1,137)**	—	—	1	**(1,136)**
Revenues	**5,487**	4,689	645	187	**11,008**
Expenses					
Purchased Product (4)	**—**	—	645	124	**769**
Transportation and Blending	**894**	4,689	—	58	**5,641**
Operating	**1,398**	—	—	15	**1,413**
Netback	**3,195**	—	—	(10)	**3,185**
Realized (Gain) Loss on Risk Management	**(1)**	—	—	—	**(1)**
Operating Margin	**3,196**	—	—	(10)	**3,186**

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

(2) Other includes construction, transportation and blending.

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

(4) Comparative periods reflect certain revisions. See Note 24 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Conventional

Three Months Ended June 30, 2024 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	 Other [1]	Conventional [2]
Gross Sales	**248**	411	32	**691**
Royalties	**(22)**	—	—	**(22)**
Revenues	**226**	411	32	**669**
Expenses				
Purchased Product	**—**	411	1	**412**
Transportation and Blending	**59**	—	24	**83**
Operating	**126**	—	6	**132**
Netback	**41**	—	1	**42**
Realized (Gain) Loss on Risk Management	**—**	—	—	**—**
Operating Margin	**41**	—	1	**42**

Three Months Ended June 30, 2023 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	 Other [1]	Conventional [2]
Gross Sales [3]	**238**	337	45	**620**
Royalties	**(5)**	—	1	**(4)**
Revenues	**233**	337	46	**616**
Expenses				
Purchased Product [3]	**—**	337	—	**337**
Transportation and Blending [3]	**39**	—	27	**66**
Operating	**139**	—	5	**144**
Netback	**55**	—	14	**69**
Realized (Gain) Loss on Risk Management	**(4)**	—	—	**(4)**
Operating Margin	**59**	—	14	**73**

(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.
(3) Comparative periods reflect certain revisions. See Note 24 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Six Months Ended June 30, 2024 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	 Other [1]	Conventional [2]
Gross Sales	**610**	893	67	**1,570**
Royalties	**(46)**	—	—	**(46)**
Revenues	**564**	893	67	**1,524**
Expenses				
Purchased Product	**—**	893	1	**894**
Transportation and Blending	**110**	—	51	**161**
Operating	**269**	—	16	**285**
Netback	**185**	—	(1)	**184**
Realized (Gain) Loss on Risk Management	**(7)**	—	—	**(7)**
Operating Margin	**192**	—	(1)	**191**

Six Months Ended June 30, 2023 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	 Other [1]	Conventional [2]
Gross Sales [3]	**729**	820	108	**1,657**
Royalties	**(59)**	—	1	**(58)**
Revenues	**670**	820	109	**1,599**
Expenses				
Purchased Product [3]	**—**	820	—	**820**
Transportation and Blending [3]	**84**	—	63	**147**
Operating	**285**	—	9	**294**
Netback	**301**	—	37	**338**
Realized (Gain) Loss on Risk Management	**4**	—	—	**4**
Operating Margin	**297**	—	37	**334**

(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.
(3) Comparative periods reflect certain revisions. See Note 24 of the interim Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Offshore

Three Months Ended June 30, 2024 ($ millions)	Basis of Netback Calculation: Atlantic	China	Indonesia [1]	Total Asia Pacific	Total Offshore	Adjustments: Equity Adjustment [1]	Other [2]	Total Offshore [3]
Gross Sales	151	320	79	**399**	**550**	(79)	—	**471**
Royalties	1	(24)	(14)	**(38)**	**(37)**	14	—	**(23)**
Revenues	152	296	65	**361**	**513**	(65)	—	**448**
Expenses								
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	7	—	—	**—**	**7**	—	—	**7**
Operating	106	29	13	**42**	**148**	(11)	5	**142**
Netback	39	267	52	**319**	**358**	(54)	(5)	**299**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**358**	(54)	(5)	**299**

Three Months Ended June 30, 2023 ($ millions)	Basis of Netback Calculation: Atlantic	China	Indonesia [1]	Total Asia Pacific	Total Offshore	Adjustments: Equity Adjustment [1]	Other [2]	Total Offshore [3]
Gross Sales	5	223	79	**302**	**307**	(79)	—	**228**
Royalties	(1)	(12)	(18)	**(30)**	**(31)**	18	—	**(13)**
Revenues	4	211	61	**272**	**276**	(61)	—	**215**
Expenses								
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	4	—	—	**—**	**4**	—	—	**4**
Operating	36	33	12	**45**	**81**	(10)	(8)	**63**
Netback	(36)	178	49	**227**	**191**	(51)	8	**148**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**191**	(51)	8	**148**

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

Six Months Ended June 30, 2024 ($ millions)	Basis of Netback Calculation: Atlantic	China	Indonesia [1]	Total Asia Pacific	Total Offshore	Adjustments: Equity Adjustment [1]	Other [2]	Total Offshore [3]
Gross Sales	193	635	147	**782**	**975**	(147)	—	**828**
Royalties	(1)	(48)	(19)	**(67)**	**(68)**	19	—	**(49)**
Revenues	192	587	128	**715**	**907**	(128)	—	**779**
Expenses								
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	7	—	—	**—**	**7**	—	—	**7**
Operating	163	54	28	**82**	**245**	(23)	5	**227**
Netback	22	533	100	**633**	**655**	(105)	(5)	**545**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**655**	(105)	(5)	**545**

Six Months Ended June 30, 2023 ($ millions)	Basis of Netback Calculation: Atlantic	China	Indonesia [1]	Total Asia Pacific	Total Offshore	Adjustments: Equity Adjustment [1]	Other [2]	Total Offshore [3]
Gross Sales	154	547	152	**699**	**853**	(152)	—	**701**
Royalties	(9)	(30)	(41)	**(71)**	**(80)**	41	—	**(39)**
Revenues	145	517	111	**628**	**773**	(111)	—	**662**
Expenses								
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	9	—	—	**—**	**9**	—	—	**9**
Operating	121	55	26	**81**	**202**	(20)	23	**205**
Netback	15	462	85	**547**	**562**	(91)	(23)	**448**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**562**	(91)	(23)	**448**

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

Upstream Sales Volumes [1]

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(MBOE/d)	**2024**	2023	**2024**	2023
Oil Sands				
Foster Creek	**185.4**	175.7	**189.7**	179.6
Christina Lake	**218.1**	231.4	**230.1**	234.6
Sunrise	**51.0**	47.2	**46.6**	43.5
Lloydminster	**130.0**	123.8	**129.2**	119.8
Total Oil Sands	**584.5**	578.1	**595.6**	577.5
Conventional	**123.1**	104.6	**121.9**	114.2
Offshore				
Atlantic	**14.8**	—	**9.4**	7.8
Asia Pacific				
China	**43.5**	31.2	**43.6**	37.2
Indonesia	**14.3**	15.0	**14.2**	14.3
Total Asia Pacific	**57.8**	46.2	**57.8**	51.5
Total Offshore	**72.6**	46.2	**67.2**	59.3
Sales Before Internal Consumption	**780.2**	728.9	**784.7**	751.0
Internal Consumption [2]	**(96.8)**	(86.8)	**(101.3)**	(89.0)
Total Upstream Sales	**683.4**	642.1	**683.4**	662.0

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

Prior Period Revisions

Certain comparative information presented in the Consolidated Statements of Comprehensive Income (Loss) and segment disclosures was revised for classification changes.

Classification Revisions

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

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

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

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

	Three Months Ended June 30, 2023			Six Months Ended June 30, 2023		
($ millions)	Previously Reported	Revisions	Revised Balance	Previously Reported	Revisions	Revised Balance
Oil Sands Segment						
Gross Sales	6,556	(119)	**6,437**	12,467	(323)	**12,144**
Purchased Product	533	(119)	**414**	1,092	(323)	**769**
	6,023	—	**6,023**	11,375	—	**11,375**
Conventional Segment						
Gross Sales	615	5	**620**	1,646	11	**1,657**
Purchased Product	352	(15)	**337**	862	(42)	**820**
Transportation and Blending	46	20	**66**	94	53	**147**
	217	—	**217**	690	—	**690**
U.S. Refining Segment						
Gross Sales	6,198	(134)	**6,064**	12,058	(365)	**11,693**
Purchased Product	5,498	(134)	**5,364**	10,627	(365)	**10,262**
	700	—	**700**	1,431	—	**1,431**
Corporate and Eliminations Segment						
Gross Sales	(2,092)	248	**(1,844)**	(4,017)	677	**(3,340)**
Purchased Product	(1,757)	287	**(1,470)**	(3,256)	766	**(2,490)**
Transportation and Blending	(109)	(98)	**(207)**	(250)	(232)	**(482)**
Operating	(185)	59	**(126)**	(416)	143	**(273)**
	(41)	—	**(41)**	(95)	—	**(95)**
Consolidated						
Purchased Product	5,709	19	**5,728**	11,501	36	**11,537**
Transportation and Blending	2,641	(78)	**2,563**	5,494	(179)	**5,315**
Purchased Product, Transportation and Blending (1)	8,350	(59)	**8,291**	16,995	(143)	**16,852**
Operating	1,541	59	**1,600**	3,093	143	**3,236**
	9,891	—	**9,891**	20,088	—	**20,088**

(1) *Revised presentation as of January 1, 2024. See Note 3 to the interim Consolidated Financial Statements.*