Cenovus Energy Inc.

Management's Discussion and Analysis (unaudited)

For the Period Ended March 31, 2024

(Canadian Dollars)

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the period ended March 31, 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 April 30, 2024, should be read in conjunction with our March 31, 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 April 30, 2024, unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus management ("Management") prepared the MD&A. The Audit Committee of the Cenovus Board of Directors ("the Board"), reviewed and recommended the MD&A for approval by the Board, which occurred on April 30, 2024. Additional information about Cenovus, including our quarterly and annual reports, Annual Information Form ("AIF") and Form 40-F, is available on SEDAR+ at sedarplus.ca, on EDGAR at sec.gov, and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, do not constitute part of this MD&A.

Basis of Presentation

This MD&A and the interim Consolidated Financial Statements were prepared in Canadian dollars, (which includes references to "dollar" or "$"), except where another currency is indicated, and in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board (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 and sustainability leadership; 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. For further details, see the Outlook section of this MD&A and our 2024 Corporate Guidance dated December 13, 2023, available on our website at cenovus.com.

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

During the first quarter of 2024, we saw strong operational performance from our Oil Sands and Canadian Refining assets, and improved operational performance from our U.S. Refining assets. Crude oil benchmark prices remained strong compared with the fourth quarter of 2023, and while the Chicago 3-2-1 market crack spreads were volatile in the quarter, they averaged 32 percent higher than the fourth quarter of 2023. The strong operational performance, combined with strong benchmark pricing, resulted in solid financial results.

- **Executed on our number one priority.** We delivered safe operations across our business, and we continue to strive to improve our safety record. Safety continues to be our top priority.
- **Delivered solid upstream performance.** Upstream production averaged 800.9 thousand barrels of oil equivalent per day in the first quarter, compared with 808.6 thousand barrels of oil equivalent per day in the fourth quarter of 2023. We achieved strong performance at our Lloydminster thermal assets due to high reliability as a result of successful redevelopment programs. At the White Rose field in the Atlantic Region, production was suspended in late December 2023 for the planned asset life extension ("ALE") project on the SeaRose floating production, storage and offloading unit ("FPSO"), and refit work has commenced. This production decline was partially offset by production at Terra Nova due to the FPSO resuming production in November 2023.
- **Achieved Strong operational performance at our Canadian Refining assets.** Crude oil unit throughput ("throughput") at our Canadian Refining assets was 104.1 thousand barrels per day, an increase of 3.8 thousand barrels per day from the fourth quarter of 2023. Total production was 116.2 thousand barrels per day, an increase of 2.9 thousand barrels per day from the fourth quarter of 2023. Crude utilization in the Canadian Refining segment was 94 percent (fourth quarter of 2023 – 91 percent).
- **Improved performance at our U.S. Refining assets**. Throughput at our U.S. refineries was 551.1 thousand barrels per day in the quarter, an increase of 72.3 thousand barrels per day from the fourth quarter of 2023. Total refined product production in the segment increased 71.8 thousand barrels per day to 585.9 thousand barrels per day. Crude utilization in the U.S. Refining segment was 87 percent, an increase from 75 percent in the fourth quarter of 2023.
- **Reported Solid financial results.** Net earnings increased to $1.2 billion from $743 million in the fourth quarter of 2023. Adjusted funds flow increased to $2.2 billion from $2.1 billion, mainly due to improved refining benchmark prices and the strong operating results. Cash flow from operating activities was $1.9 billion, down from $2.9 billion in the fourth quarter of 2023, as the higher Operating Margin was more than offset by changes in non-cash working capital.
- **Progressed towards our Net Debt target.** We continued to move towards our $4.0 billion Net Debt target. Net Debt was $4.8 billion as at March 31, 2024, compared with $5.1 billion as at December 31, 2023.
- **Delivered significant cash returns to shareholders.** We returned $436 million to shareholders, composed of the purchase of 7.4 million common shares for $165 million through our normal course issuer bid ("NCIB"), and $271 million through common share base dividends and preferred share dividends. On April 30, 2024, our Board of Directors declared a second quarter base dividend of $0.180 per common share, a 29 percent increase from the first quarter dividend declared in February 2024, and a variable dividend of $0.135 per common share.
- **Achieved our credit ratings target.** We achieved our mid-BBB credit ratings target with all agencies, following S&P Global's upgrade of Cenovus to BBB with a Stable outlook on March 18, 2024. This upgrade is a reflection of our debt reduction, financial policy track record and operational momentum.

- **Commenced Pathways Alliance ("Pathways") regulatory filings.** On March 22, 2024, Pathways announced it has commenced regulatory applications to the Alberta Energy Regulator for the proposed carbon transportation network and storage hub project. As proposed, the project would be one of the world's largest carbon capture systems and would play a significant role in helping Canada progress its net zero ambitions.

Summary of Quarterly Results

	2024	2023				2022			
($ millions, except where indicated)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upstream Production Volumes [1] (MBOE/d)	**800.9**	808.6	797.0	729.9	779.0	806.9	777.9	761.5	798.6
Crude Oil Unit Throughput [2] (Mbbls/d)	**655.2**	579.1	664.3	537.8	457.9	473.3	533.5	457.3	501.8
Downstream Production Volumes [2] (Mbbls/d)	**702.1**	627.4	706.0	571.9	487.7	506.3	572.6	482.1	538.0
Revenues	**13,397**	13,134	14,577	12,231	12,262	14,063	17,471	19,165	16,198
Operating Margin [3]	**3,191**	2,151	4,369	2,400	2,102	2,782	3,339	4,678	3,464
Cash From (Used In) Operating Activities	**1,925**	2,946	2,738	1,990	(286)	2,970	4,089	2,979	1,365
Adjusted Funds Flow [3]	**2,242**	2,062	3,447	1,899	1,395	2,346	2,951	3,098	2,583
Per Share - Basic [3] ($)	**1.20**	1.10	1.82	1.00	0.73	1.22	1.53	1.57	1.30
Per Share - Diluted [3] ($)	**1.19**	1.09	1.81	0.98	0.71	1.19	1.49	1.53	1.27
Capital Investment	**1,036**	1,170	1,025	1,002	1,101	1,274	866	822	746
Free Funds Flow [3]	**1,206**	892	2,422	897	294	1,072	2,085	2,276	1,837
Excess Free Funds Flow [3]	**832**	471	1,989	505	(499)	786	1,756	2,020	2,615
Net Earnings (Loss)	**1,176**	743	1,864	866	636	784	1,609	2,432	1,625
Per Share - Basic ($)	**0.62**	0.39	0.98	0.45	0.33	0.40	0.83	1.23	0.81
Per Share - Diluted ($)	**0.62**	0.39	0.97	0.44	0.32	0.39	0.81	1.19	0.79
Total Assets	**54,994**	53,915	54,427	53,747	54,000	55,869	55,086	55,894	55,655
Total Long-Term Liabilities	**18,884**	18,993	18,395	19,831	19,917	20,259	19,378	20,742	21,889
Long-Term Debt, Including Current Portion	**7,227**	7,108	7,224	8,534	8,681	8,691	8,774	11,228	11,744
Net Debt	**4,827**	5,060	5,976	6,367	6,632	4,282	5,280	7,535	8,407
Cash Returns to Shareholders	**436**	731	1,225	584	258	807	873	1,233	544
Common Shares – Base Dividends	**262**	261	264	265	200	201	205	207	69
Base Dividends Per Common Share ($)	**0.140**	0.140	0.140	0.140	0.105	0.105	0.105	0.105	0.035
Common Shares – Variable Dividends	**—**	—	—	—	—	219	—	—	—
Variable Dividends Per Common Share ($)	**—**	—	—	—	—	0.114	—	—	—
Purchase of Common Shares Under NCIB	**165**	350	361	310	40	387	659	1,018	466
Payment for Purchase of Warrants	**—**	111	600	—	—	—	—	—	—
Preferred Share Dividends	**9**	9	—	9	18	—	9	8	9

(1) Refer to the Operating and Financial Results section of this MD&A for a summary of total upstream production by product type.
(2) Represents Cenovus's net interest in refining operations.
(3) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results — Upstream

	Three Months Ended March 31,		
	2024	Percent Change	2023
Upstream Production Volumes by Segment [1] (MBOE/d)			
Oil Sands	**615.3**	**4**	589.5
Conventional	**120.7**	**(3)**	123.9
Offshore	**64.9**	**(1)**	65.6
Total Production Volumes	**800.9**	**3**	779.0
Upstream Production Volumes by Product			
Bitumen (Mbbls/d)	**595.4**	**4**	570.7
Heavy Crude Oil (Mbbls/d)	**17.9**	**7**	16.8
Light Crude Oil (Mbbls/d)	**12.5**	**(18)**	15.3
NGLs (Mbbls/d)	**32.4**	**(3)**	33.4
Conventional Natural Gas (MMcf/d)	**855.8**	**—**	857.0
Total Production Volumes (MBOE/d)	**800.9**	**3**	779.0

(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.

Total upstream production increased 21.9 thousand BOE per day in the first quarter of 2024 compared with 2023 due to:

- Successful results from the base well optimization at our Sunrise and Lloydminster thermal assets.
- Successful results from the 2023 redevelopment programs at our Lloydminster thermal assets.
- The Terra Nova FPSO resuming production in late November 2023.

The increases were partially offset by:

- Suspended production on the SeaRose FPSO for the planned ALE project. We expect to resume production at the White Rose field late in the third quarter of 2024.

Selected Operating Results — Downstream

	Three Months Ended March 31,		
	2024	Percent Change	2023
Downstream Crude Oil Unit Throughput by Segment (Mbbls/d)			
Canadian Refining	**104.1**	**5**	98.7
U.S. Refining	**551.1**	**53**	359.2
Total Crude Oil Unit Throughput	**655.2**	**43**	457.9
Downstream Production Volumes by Segment [1] (Mbbls/d)			
Canadian Refining	**116.2**	**3**	112.9
U.S. Refining	**585.9**	**56**	374.8
Total Downstream Production	**702.1**	**44**	487.7

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

The Canadian Refining assets operated reliably in the first quarter of 2024, with crude utilization at the Lloydminster Upgrader (or the "Upgrader") and Lloydminster Refinery averaging 94 percent (2023 – 89 percent). The improved performance year over year was driven by consistent operations in the quarter, compared with cold weather and operational outages that impacted the Upgrader early in the first quarter of 2023.

In our U.S. Refining operations, throughput increased by 191.9 thousand barrels per day as we:

- Achieved crude utilization of 87 percent (2023 – 67 percent).
- Obtained the benefit of a full quarter of production at the Toledo Refinery and the Superior Refinery.
- Took advantage of favourable market conditions since the end of January at the Wood River and Borger refineries, combined with planned turnarounds and unplanned outages at both refineries in 2023.

The increases were partially offset by:

- Flexed throughput at our U.S. refineries to optimize our margins due to significantly lower benchmark prices early in the quarter.
- An unplanned outage at the Lima Refinery.
- A planned third-party hydrogen outage that impacted throughput at the Toledo Refinery.
- An unplanned outage caused by a winter freeze-up that reduced throughput and refined product production at the Superior Refinery.

Selected Consolidated Financial Results

Revenues

Revenues increased nine percent to $13.4 billion compared with the first quarter of 2023, primarily due to increased crude oil production and higher blended crude oil benchmark pricing impacting our Oil Sands segment, and higher downstream production primarily due to the restart of the Toledo and Superior refineries. The increase was partially offset by lower natural gas, synthetic crude oil and refined product pricing.

Operating Margin

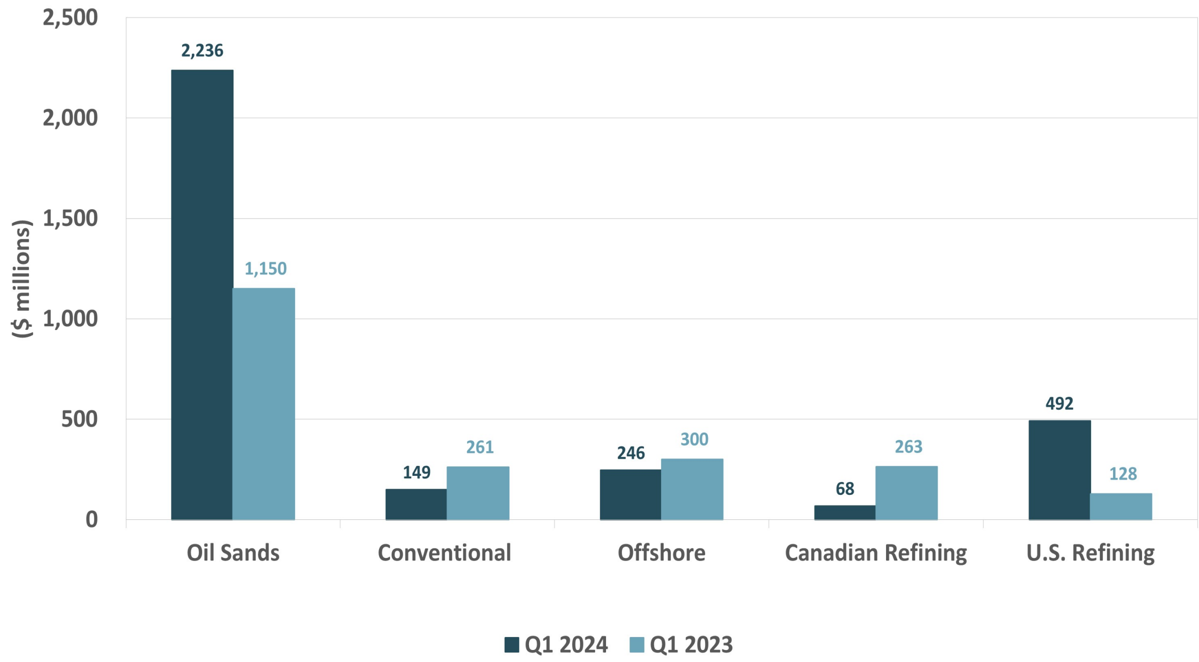
Operating Margin is a non-GAAP measure and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods.

	Three Months Ended March 31,	
($ millions)	**2024**	2023
Gross Sales [1]	**16,431**	14,354
Royalties	**(747)**	(596)
Revenues	**15,684**	13,758
Expenses		
Purchased Product [1]	**7,990**	6,829
Transportation and Blending [1]	**2,811**	3,027
Operating Expenses	**1,685**	1,783
Realized (Gain) Loss on Risk Management Activities	**7**	17
Operating Margin	**3,191**	2,102

(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 March 31, 2024 and 2023



Operating Margin increased $1.1 billion to $3.2 billion in the first quarter of 2024 compared with the same period in 2023, primarily due to:

- Higher crude oil production and higher crude oil benchmark pricing impacting our Oil Sands segment.
- Increased refined product production at the Toledo Refinery and the Superior Refinery due to a full quarter of operations.
- Recognizing a benefit from the acquisition of the remaining 50 percent interest in the Toledo Refinery from bp Products North America Inc. (the "Toledo Acquisition"), which allows us to better use existing resources across our U.S portfolio to improve our product mix.

These increases were partially offset by:

- Lower natural gas benchmark pricing impacting our Conventional segment.
- Lower sales volumes from our Offshore segment.
- Lower Operating Margin from the Canadian Refining segment, primarily due to the narrowing of the Upgrading Differential to $19.31 per barrel.
- Lower market crack spreads impacting our U.S. Refining segment.

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

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

	Three Months Ended March 31,	
($ millions)	**2024**	2023
Cash From (Used in) Operating Activities	**1,925**	(286)
(Add) Deduct:		
Settlement of Decommissioning Liabilities	**(48)**	(48)
Net Change in Non-Cash Working Capital	**(269)**	(1,633)
Adjusted Funds Flow	**2,242**	1,395

Cash from operating activities increased in the first three months of 2024 compared with 2023. The increase was primarily due to higher Operating Margin in 2024, as discussed above, and changes in non-cash working capital. The net change in non-cash working capital in 2024 of negative $269 million was primarily driven by higher accounts receivable, accounts payable and inventory due to higher crude oil and refined product pricing. In the first quarter of 2023, changes in non-cash working capital from operating activities decreased cash by $1.6 billion, primarily driven by an income tax payment of $1.2 billion, that occurred during the period.

Adjusted Funds Flow was higher in the first quarter of 2024 compared with 2023, primarily due to higher Operating Margin, partially offset by higher long-term incentive costs paid in the quarter and higher current tax expense.

Net Earnings (Loss)

Net earnings in the first quarter of 2024 was $1.2 billion, compared with $636 million in 2023. The increase was primarily due to higher Operating Margin as discussed above and a gain on asset divestitures, partially offset by higher income tax expense, and general and administrative costs.

Net Debt

As at ($ millions)	**March 31, 2024**	December 31, 2023
Short-Term Borrowings	**—**	179
Long-Term Portion of Long-Term Debt	**7,227**	7,108
Total Debt	**7,227**	7,287
Cash and Cash Equivalents	**(2,400)**	(2,227)
Net Debt	**4,827**	5,060

Net Debt decreased by $233 million from December 31, 2023, mainly due to cash from operating activities of $1.9 billion, partially offset by capital investment of $1.0 billion, cash returns to shareholders of $436 million 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 March 31,	
($ millions)	**2024**	2023
Upstream		
Oil Sands	**647**	635
Conventional	**126**	141
Offshore	**159**	100
Total Upstream	**932**	876
Downstream		
Canadian Refining	**31**	27
U.S. Refining	**67**	194
Total Downstream	**98**	221
Corporate and Eliminations	**6**	4
Total Capital Investment	**1,036**	1,101

(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 quarter 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 tie-back of Narrows Lake to Christina Lake and other sustaining projects at Foster Creek, Lloydminster thermal assets and Sunrise.
- The progression of the West White Rose project in the Atlantic region.
- Drilling, completion and infrastructure projects in the Conventional segment.
- Sustaining activities at our operated refining assets and refining reliability projects at our non-operated Wood River and Borger refineries.

Drilling Activity

	Net Stratigraphic Test Wells and Observation Wells		Net Production Wells (1)	
Three Months Ended March 31,	**2024**	2023	**2024**	2023
Foster Creek	**82**	87	**7**	3
Christina Lake	**58**	53	**1**	3
Sunrise	**40**	38	**—**	—
Lloydminster Thermal	**—**	1	**3**	—
Lloydminster Conventional Heavy Oil	**—**	1	**2**	3
Other	**—**	3	**—**	—
	180	183	**13**	9

(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.

	Three Months Ended March 31, 2024			Three Months Ended March 31, 2023		
(net wells)	**Drilled**	**Completed**	**Tied-in**	Drilled	Completed	Tied-in
Conventional	**16**	**11**	**5**	14	15	16

No wells were drilled or completed in the Offshore segment in the first quarter of 2024 (2023 – drilled and completed one (0.4 net) development well at the MAC field in Indonesia).

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates [1]

(Average US$/bbl, unless otherwise indicated)	Q1 2024	Percent Change	Q1 2023	Q4 2023
Dated Brent	**83.24**	**2**	81.27	84.05
WTI	**76.96**	**1**	76.13	78.32
Differential Dated Brent - WTI	**6.28**	**22**	5.14	5.73
WCS at Hardisty	**57.65**	**12**	51.36	56.43
Differential WTI - WCS at Hardisty	**19.31**	**(22)**	24.77	21.89
WCS at Hardisty (C$/bbl)	**77.77**	**12**	69.44	76.95
WCS at Nederland	**69.89**	**12**	62.49	71.59
Differential WTI - WCS at Nederland	**7.07**	**(48)**	13.64	6.73
Condensate (C5 at Edmonton)	**72.78**	**(9)**	79.87	76.24
Differential Condensate - WTI Premium/(Discount)	**(4.18)**	**(212)**	3.74	(2.08)
Differential Condensate - WCS at Hardisty Premium/(Discount)	**15.13**	**(47)**	28.51	19.81
Condensate (C$/bbl)	**98.18**	**(9)**	107.95	103.90
Synthetic at Edmonton	**69.42**	**(11)**	78.18	78.64
Differential Synthetic - WTI Premium/(Discount)	**(7.54)**	**(468)**	2.05	0.32
Synthetic at Edmonton (C$/bbl)	**93.65**	**(11)**	105.67	107.21
Refined Product Prices				
Chicago Regular Unleaded Gasoline ("RUL")	**89.48**	**(10)**	99.82	83.72
Chicago Ultra-low Sulphur Diesel ("ULSD")	**104.27**	**(10)**	115.39	107.24
Refining Benchmarks				
Chicago 3-2-1 Crack Spread [2]	**17.45**	**(40)**	28.88	13.24
Group 3 3-2-1 Crack Spread [2]	**17.50**	**(44)**	31.35	18.55
Renewable Identification Numbers ("RINs")	**3.68**	**(55)**	8.20	4.77
Natural Gas Prices				
AECO [3] (C$/Mcf)	**2.50**	**(22)**	3.22	2.30
NYMEX [4] (US$/Mcf)	**2.24**	**(35)**	3.42	2.88
Foreign Exchange Rates				
US$ per C$1 - Average	**0.741**	**—**	0.739	0.734
US$ per C$1 - End of Period	**0.738**	**—**	0.739	0.756
RMB per C$1 - Average	**5.330**	**5**	5.059	5.304

(1) These benchmark prices are not our realized sales prices and represent approximate values. For our average realized sales prices and realized risk management results, refer to the Netback tables in the Reportable Segments section of this MD&A.
(2) The average 3-2-1 crack spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.
(3) Alberta Energy Company ("AECO") 5A natural gas daily index.
(4) New York Mercantile Exchange ("NYMEX") natural gas monthly index.

Crude Oil and Condensate Benchmarks

In the first quarter of 2024, crude oil benchmark prices, Brent and WTI, increased slightly compared with the first quarter of 2023 and remain generally in line with the fourth quarter of 2023. Global crude supply and demand has been relatively balanced since the beginning of 2023, as continued extensions of OPEC+ production cuts have offset production growth elsewhere globally and supported prices. Geopolitical uncertainty surrounding the Russia Ukraine conflict remains the largest immediate geopolitical risk related to crude oil and refined product prices. A variety of other geopolitical events in areas including Israel/Gaza, the Red Sea, Venezuela, and Guyana added to volatility in the first quarter of 2024, but have had a limited impact on global oil markets to date.

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

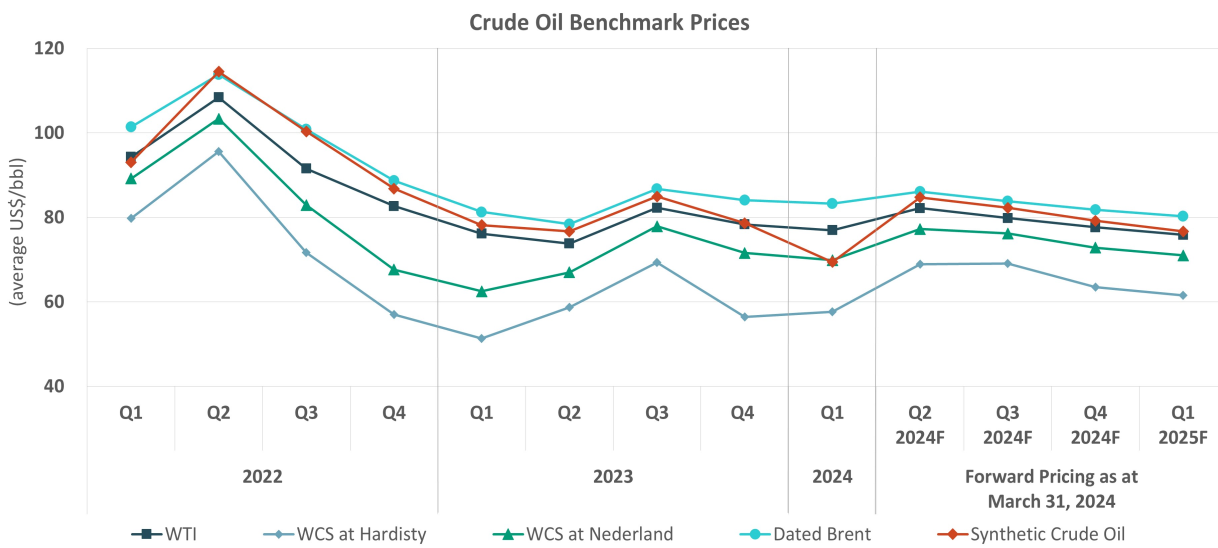
The price received for our Atlantic crude oil and Asia Pacific NGLs is primarily driven by the price of Brent. The Brent-WTI differential widened in the first quarter of 2024 compared with the first and fourth quarters of 2023, reflecting modestly elevated freight rates.

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. For the first quarter of 2024, the average WTI-WCS differential at Hardisty narrowed compared with the first quarter of 2023, largely due to the narrowing of the quality differential. The first quarter of 2023 saw 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. 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. High Alberta production led to exports being near or above pipeline capacity in the first quarter of 2024; however, this had a minimal impact to the WCS differential year over year. As expected, the start-up of the Trans Mountain pipeline expansion in 2024 is having a narrowing impact on WTI-WCS differentials.

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. The WTI-WCS at Nederland differential narrowed in the first quarter of 2024 compared with the first quarter of 2023, due to the same factors impacting the WTI-WCS differential at Hardisty discussed above.

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

In the first quarter of 2024, synthetic crude oil at Edmonton was priced at a discount to WTI, compared with a premium in the first quarter of 2023. Synthetic crude regularly trades at a premium to WTI. The weakness in pricing in the first quarter of 2024 was a result of high synthetic crude oil production in Alberta, an over supply of light crude which results 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 20 percent to 35 percent. The WCS-Condensate differential is an important benchmark, as a wider differential generally results in a decrease in the recovery of condensate costs when selling a barrel of blended crude oil. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by USGC condensate prices plus the cost to transport the condensate to Edmonton. Our blending costs are also impacted by the timing of purchases and deliveries of condensate into inventory to be available for use in blending, as well as timing of sales of blended product.

In the first quarter of 2024, the average Edmonton condensate benchmark traded at a discount to WTI compared to a premium in the first quarter of 2023. This was driven by weakness in light crude and synthetic prices in Alberta as over supply of light crude was above pipeline takeaway capacity.

Refining Benchmarks

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

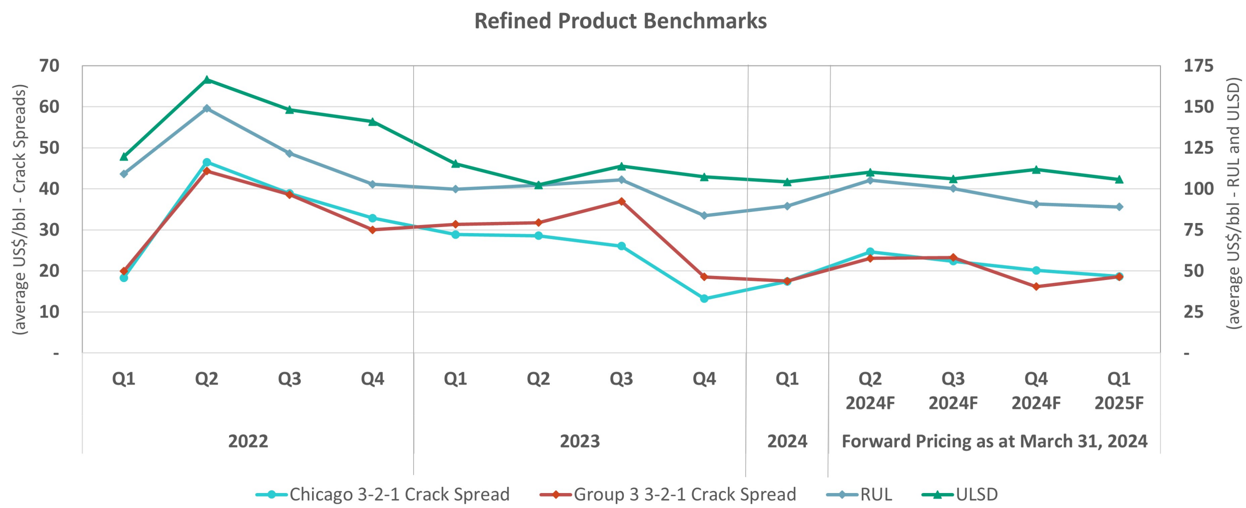
The Chicago 3-2-1 market crack spread reflects the market for the Toledo, Lima and Wood River refineries. The Group 3 3-2-1 market crack spread reflects the market for the Superior and Borger refineries.

Refined product prices declined in the first quarter of 2024 compared with the same period in 2023, as incremental global capacity additions weighed on global refinery crack spreads, and Chicago area refinery production, driven by access to cheaper feedstock and high distillate pricing, led to an excess supply of refined products and large inventory builds, pressuring Chicago pricing relative to other markets. Towards the end of the first quarter of 2024, planned and unplanned refinery maintenance in the Chicago area strengthened refined product pricing in Chicago.

The average RINs costs were also lower in the quarter compared with the first quarter 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 reflects the differential between Brent and WTI benchmark prices.

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



Natural Gas Benchmarks

Average NYMEX and AECO natural gas prices decreased in the first quarter of 2024 compared with 2023, as U.S. supply rapidly grew to record high levels exceeding demand growth, which has led to high levels of inventory. 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 first quarter of 2024, on average, the Canadian dollar strengthened relative to the U.S. dollar, compared with the first quarter of 2023, negatively impacting our reported revenues. The Canadian dollar weakened relative to the U.S. dollar as at March 31, 2024, compared with December 31, 2023, resulting in unrealized foreign exchange losses on the translation of our U.S. dollar debt.

A portion of our long-term sales contracts in the Asia Pacific region are priced in RMB. An increase in the value of the Canadian dollar relative to the RMB will decrease the revenues received in Canadian dollars from the sale of natural gas commodities in the region. In the first quarter of 2024, on average, the Canadian dollar strengthened relative to RMB, compared with the first quarter of 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 March 31, 2024, the Bank of Canada's Policy Interest Rate was five percent. On April 10, 2024, the Bank of Canada announced the rate will remain at five percent.

OUTLOOK

Commodity Price Outlook

Global crude oil prices remain generally in line with the fourth quarter of 2023, as continued extensions of OPEC+ production cuts have supported prices. The current voluntary cuts have been extended to the end of the second quarter of 2024. Non-OPEC+ supply growth, led by U.S. shale, has been robust and is expected to continue to grow through 2024. 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. Geopolitical uncertainty surrounding the Russia Ukraine conflict remains the largest immediate geopolitical risk related to crude oil and refined product prices.

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, 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.

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 the Trans Mountain pipeline expansion in 2024 is having a narrowing impact on WTI-WCS differentials.
- We expect refined product prices and market crack spreads will remain volatile. Economic effects of the ongoing Russian invasion of Ukraine and central bank policies could impact demand. Refined product prices and market crack spreads are likely to continue to fluctuate, adjusting for seasonal trends and refinery utilization in North America.
- NYMEX and AECO natural gas prices are expected to remain under pressure in the near-term due to strong supply and ample natural gas in storage. Weather will continue to be a key driver of demand and impact prices.
- We expect the Canadian dollar to continue to be impacted by 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 leadership.

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. Our ultimate Net Debt target is $4.0 billion, and we strive to continue to make progress towards this target. 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 Foster Creek optimization project. 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 has always been deeply engrained in Cenovus's culture. We have established ambitious targets in our five environmental, social and governance ("ESG") focus areas and continue to progress tangible plans to meet these targets.

We have allocated resources to invest in our five ESG focus areas, including emissions reduction initiatives. 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 decarbonization projects, while maintaining global competitiveness. It is critical that the federal and provincial governments provide support at a level consistent with what other large-scale decarbonization projects are receiving globally. This will enable the Canadian oil and gas sector to achieve its greenhouse gas ("GHG") emissions reduction goals and remain competitive with other oil and gas producing jurisdictions.

Additional information on Cenovus's efforts and targets are available in Cenovus's 2022 ESG report on our website at cenovus.com.

REPORTABLE SEGMENTS

UPSTREAM

Oil Sands

In the first quarter of 2024, we:

- Delivered safe and reliable operations.
- Produced 613.3 thousand barrels of crude oil per day (2023 – 587.5 thousand barrels of crude oil per day).
- Brought on the first new well pad in three years at Sunrise.
- Delivered successful results from the base well optimization at our Sunrise and Lloydminster thermal assets, and the redevelopment programs at our Lloydminster thermal assets.
- Generated Operating Margin of $2.2 billion, an increase of $1.1 billion compared with 2023, primarily due to higher realized sales prices and increased sales volumes.
- Invested capital of $647 million primarily for sustaining activities, including the drilling of stratigraphic test wells as part of our integrated winter program, the tie-back of Narrows Lake to Christina Lake and other sustaining projects at Foster Creek, Lloydminster thermal assets and Sunrise.
- Achieved a Netback of $40.79 per BOE (2023 – $22.55 per BOE).

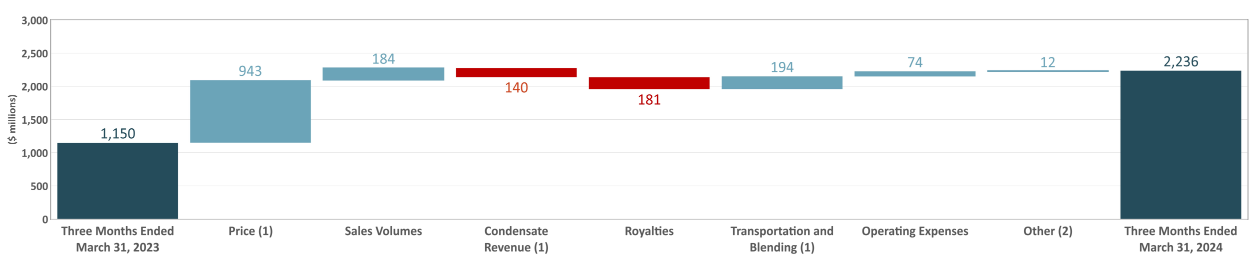
Financial Results

	Three Months Ended March 31,	
($ millions)	**2024**	2023
Gross Sales [(1)]	**6,628**	5,707
Royalties	**(697)**	(516)
Revenues	**5,931**	5,191
Expenses		
Purchased Product [(1)]	**289**	355
Transportation and Blending	**2,733**	2,941
Operating	**660**	737
Realized (Gain) Loss on Risk Management	**13**	8
Operating Margin	**2,236**	1,150
Unrealized (Gain) Loss on Risk Management	**(13)**	(34)
Depreciation, Depletion and Amortization	**774**	715
Exploration Expense	**3**	2
Segment Income (Loss)	**1,472**	467

(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 March 31, 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 March 31,	
	2024	2023
Total Sales Volumes [1] (MBOE/d)	**606.9**	577.0
Realized Sales Price [2] [3] ($/BOE)	**72.79**	55.60
Crude Oil Production by Asset (Mbbls/d)		
Foster Creek	**196.0**	190.0
Christina Lake	**236.5**	237.2
Sunrise	**48.8**	44.5
Lloydminster Thermal	**114.1**	99.0
Lloydminster Conventional Heavy Oil	**17.9**	16.8
Total Crude Oil Production [4] (Mbbls/d)	**613.3**	587.5
Natural Gas [5] (MMcf/d)	**11.9**	12.0
Total Production (MBOE/d)	**615.3**	589.5
Effective Royalty Rate [6] (percent)		
Foster Creek	**24.9**	23.4
Christina Lake	**25.0**	30.3
Sunrise	**3.8**	4.7
Lloydminster [7]	**6.8**	8.3
Total Effective Royalty Rate	**19.3**	21.4
Transportation and Blending Expense [8] ($/BOE)	**7.54**	9.07
Operating Expense [8] ($/BOE)	**11.86**	14.04
Per-Unit DD&A [8] ($/BOE)	**13.35**	12.72

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

Revenues

In the first quarter of 2024, gross sales increased to $6.6 billion from $5.7 billion in 2023. The increase was primarily due to the narrowing WTI-WCS differential at Hardisty to US$19.31 per barrel (2023 – US$24.77 per barrel), and the increase in production to 613.3 thousand barrels per day from 587.5 thousand barrels per day. Royalties increased primarily due to higher gross sales compared to the first quarter of 2023.

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, our blend ratio increases and our realized heavy oil and bitumen sales price decreases.

In the first quarter of 2024, approximately 25 percent of our crude oil sales volumes were sold to third parties at U.S. destinations and approximately 20 percent of our Oil Sands crude oil sales volumes were sold to our Canadian and U.S. downstream operations. All remaining sales were at Canadian destinations.

Our realized sales price increased to $72.79 per BOE in the first quarter of 2024, from $55.60 per BOE in the first quarter of 2023, mainly due to narrower WTI-WCS differentials and narrower condensate-WCS differentials. In the first three months of 2024, WTI averaged US$76.96 per barrel (2023 – US$76.13 per barrel) and the WTI-WCS at Hardisty differential was US$19.31 per barrel (2023 – US$24.77 per barrel). Condensate benchmark pricing was at a US$15.13 per barrel premium to WCS at Hardisty in the first quarter of 2024, compared with a US$28.51 per barrel premium in the same period of 2023.

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

Production Volumes

Oil Sands crude oil production was 613.3 thousand barrels per day in the first quarter of 2024 (2023 – 587.5 thousand barrels per day).

Production at Foster Creek increased 6.0 thousand barrels per day to 196.0 thousand barrels per day compared with 2023. The increase was primarily due to three new well pads that were brought online throughout 2023 and one new pad brought online in the first quarter of 2024.

Production at Christina Lake was relatively consistent at 236.5 thousand barrels per day compared with 2023.

Production at Sunrise increased 4.3 thousand barrels per day to 48.8 thousand barrels per day compared with 2023, mainly due to successful results from our 2023 redevelopment program and base well optimization.

Production from our Lloydminster thermal assets increased 15.1 thousand barrels per day to 114.1 thousand barrels per day compared with 2023. The increase was due to strong results from new sustaining wells brought online in the first quarter of 2024 and our successful 2023 redevelopment programs.

Royalties

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

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

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

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

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

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

In the first quarter of 2024, royalties were $697 million (2023 – $516 million). Oil Sands royalties increased primarily due to improved realized pricing coupled with higher volumes. The Oil Sands effective royalty rate decreased to 19.3 percent in 2024 from 21.4 percent in 2023, primarily due to annual adjustments on the end-of-period filings.

Expenses

Transportation and Blending

In the first quarter of 2024, blending costs decreased $142 million to $2.3 billion compared with 2023, due to lower condensate prices partially offset by higher volumes. Transportation costs decreased by $66 million to $424 million in 2024 compared with 2023, mainly due to lower sales volumes to U.S. destinations and lower rail costs.

Per-Unit Transportation Expenses

Per-unit transportation decreased to $7.54 per BOE in the first quarter of 2024 from $9.07 per BOE in 2023 primarily due to higher sales volume combined with lower sales volumes to U.S. destinations.

At Foster Creek, per-unit transportation decreased to $10.25 per barrel in 2024 from $13.45 per barrel in 2023, primarily due to lower sales to U.S. destinations, resulting in lower transportation expenses. In 2024, we shipped 34 percent (2023 – 49 percent) of our volumes from Foster Creek to U.S. destinations.

At Christina Lake, per-unit transportation decreased to $5.40 per barrel in 2024 from $7.70 per barrel in 2023, mainly due to lower fixed rail costs and tariff rates. In 2024, we shipped 11 percent (2023 – 15 percent) of our volumes from Christina Lake to U.S. destinations.

At Sunrise, per-unit transportation increased to $18.51 per barrel in 2024 from $12.67 per barrel in 2023, mainly due to a higher percentage of our volumes being shipped to U.S. destinations. In 2024, we shipped 94 percent (2023 – 46 percent) of our volumes from Sunrise to U.S. destinations.

At our Lloydminster oil sands assets, per-unit transportation in 2024 were $3.89 per barrel (2023 – $3.74 per barrel).

Operating

Primary drivers of our operating expenses in the first quarter of 2024 were fuel, workforce, repairs and maintenance, and chemicals. Total operating expenses decreased $77 million to $660 million in 2024 compared with 2023, mainly driven by lower fuel costs as a result of significant declines in natural gas benchmark pricing. The decreases were partially offset by higher GHG compliance costs and repairs and maintenance costs in 2024 compared with 2023. 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 March 31,		
($/BOE)	**2024**	**Percent Change**	2023
Foster Creek			
Fuel	**3.22**	**(37)**	5.11
Non-Fuel	**7.59**	**(4)**	7.88
Total	**10.81**	**(17)**	12.99
Christina Lake			
Fuel	**2.76**	**(26)**	3.75
Non-Fuel	**5.75**	**7**	5.36
Total	**8.51**	**(7)**	9.11
Sunrise			
Fuel	**4.32**	**(35)**	6.66
Non-Fuel	**12.70**	**(17)**	15.37
Total	**17.02**	**(23)**	22.03
Lloydminster (2)			
Fuel	**4.15**	**(30)**	5.93
Non-Fuel	**13.90**	**(19)**	17.15
Total	**18.05**	**(22)**	23.08
Total Oil Sands			
Fuel	**3.31**	**(31)**	4.82
Non-Fuel	**8.55**	**(7)**	9.22
Total	**11.86**	**(16)**	14.04

(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 non-fuel costs decreased in the first three months of 2024 compared with 2023 at Foster Creek, Sunrise and Lloydminster primarily due to increased sales volumes.

Per-unit non-fuel costs increased at Christina Lake due to increased GHG compliance costs, repairs and maintenance and waste disposal costs, partially offset by increased sales volumes.

Netbacks [1]

($/BOE)	Three Months Ended March 31, 2024	2023
Sales Price	**72.79**	55.60
Royalties	**12.60**	9.94
Transportation and Blending	**7.54**	9.07
Operating Expenses	**11.86**	14.04
Netback	**40.79**	22.55

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

Conventional

In the first quarter of 2024, we:

- Delivered safe operations.
- Produced 120.7 thousand BOE per day (2023 – 123.9 thousand BOE per day).
- Generated Operating Margin of $149 million, a decrease from $261 million in 2023, primarily due to lower natural gas benchmark prices.
- Invested capital of $126 million with continued focus on drilling, completion and infrastructure projects.
- Averaged a Netback of $13.04 per BOE (2023 – $22.08 per BOE).

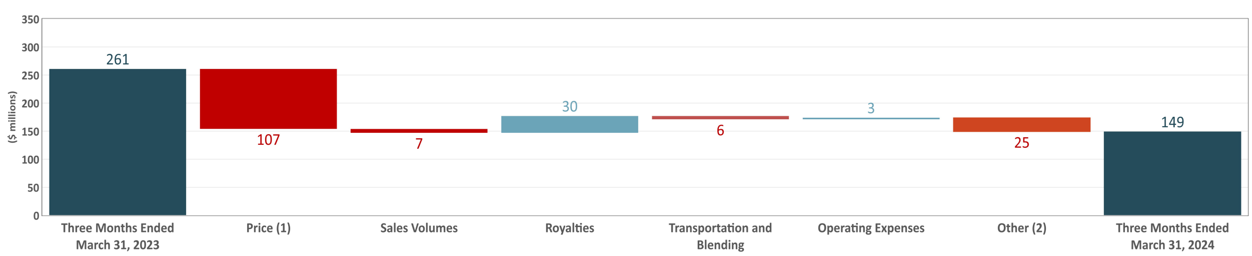
Financial Results

($ millions)	Three Months Ended March 31, 2024	2023
Gross Sales [1]	**879**	1,037
Royalties	**(24)**	(54)
Revenues	**855**	983
Expenses		
Purchased Product [1]	**482**	483
Transportation and Blending [1]	**78**	81
Operating	**153**	150
Realized (Gain) Loss on Risk Management	**(7)**	8
Operating Margin	**149**	261
Unrealized (Gain) Loss on Risk Management	**6**	(20)
Depreciation, Depletion and Amortization	**110**	95
(Income) Loss From Equity-Accounted Affiliates	**1**	—
Segment Income (Loss)	**32**	186

(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 March 31, 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 March 31,	
	2024	2023
Total Sales Volumes (MBOE/d)	**120.7**	123.9
Realized Sales Price (1) (2) ($/BOE)	**32.92**	43.99
Light Crude Oil ($/bbl)	**87.97**	102.80
NGLs ($/bbl)	**57.40**	48.05
Conventional Natural Gas ($/Mcf)	**4.00**	6.58
Production by Product		
Light Crude Oil (Mbbls/d)	**5.3**	6.4
NGLs (Mbbls/d)	**22.0**	22.0
Conventional Natural Gas (MMcf/d)	**560.5**	572.9
Total Production (MBOE/d)	**120.7**	123.9
Conventional Natural Gas Production (percentage of total)	**77**	77
Crude Oil and NGLs Production (percentage of total)	**23**	23
Effective Royalty Rate (3) (percent)	**9.9**	17.3
Transportation Expense (2) (4) ($/BOE)	**4.67**	4.03
Operating Expense (4) ($/BOE)	**13.05**	13.07
Per-Unit DD&A (4) ($/BOE)	**9.90**	8.41

(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

Gross Sales

In the first quarter of 2024, gross sales decreased to $879 million from $1.0 billion in 2023. The decrease was primarily due to lower natural gas benchmark prices, combined with a slight decrease in production to 120.7 thousand BOE per day from 123.9 thousand BOE per day.

Royalties

The Conventional assets are subject to royalty regimes in Alberta and British Columbia. Royalties decreased to $24 million in the first quarter of 2024, from $54 million in the first quarter of 2023, primarily due to declines in pricing.

Expenses

Transportation

Our transportation costs reflect charges for the movement of crude oil, NGLs and natural gas from the point of production to where the product is sold. Transportation costs decreased $3 million to $78 million in the first quarter of 2024 compared with 2023. Per-unit transportation costs increased to $4.67 per BOE in the first quarter of 2024, from $4.03 per BOE in 2023, primarily due to slightly lower sales volumes.

Operating

Primary drivers of operating expenses in the first three months of 2024 were repairs and maintenance, workforce and property tax costs. Total operating expenses and operating expenses per BOE were consistent in the first quarter of 2024 compared with 2023.

Netbacks [1]

($/BOE)	Three Months Ended March 31, 2024	2023
Sales Price [2]	**32.92**	43.99
Royalties	**2.16**	4.81
Transportation and Blending [2]	**4.67**	4.03
Operating Expenses	**13.05**	13.07
Netback	**13.04**	22.08

(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 first quarter of 2024, we:

- Delivered safe operations.
- Produced 64.9 thousand BOE per day of light crude oil, NGLs and natural gas (2023 – 65.6 thousand BOE per day).
- Averaged 7.2 thousand barrels per day (2023 – nil) at the Terra Nova FPSO, due to production resuming in November 2023.
- Generated Operating Margin of $246 million, a decrease of $54 million compared with 2023, mainly due to lower sales volumes in the Atlantic region.
- Achieved a Netback of $52.80 per BOE (2023 – $57.06 per BOE).
- Invested capital of $159 million, mainly for the West White Rose project in the Atlantic region.

In late December 2023, we suspended production at the White Rose field as we prepared for the planned SeaRose ALE project, and refit work has commenced. We expect to resume production at the White Rose field late in the third quarter of 2024.

The West White Rose project was approximately 80 percent complete as at March 31, 2024. Since our decision in 2022 to restart the project, we have invested approximately $797 million. First oil is expected in 2026.

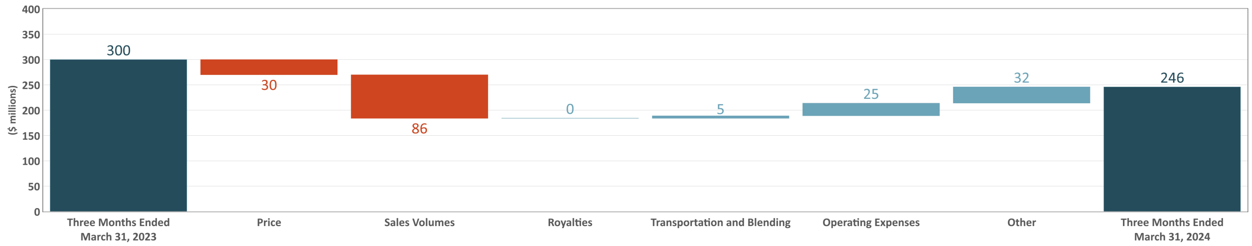
Financial Results

	Three Months Ended March 31,					
	2024			2023		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore**	Atlantic	Asia Pacific	Offshore
Gross Sales	**42**	**315**	**357**	149	324	473
Royalties	**(2)**	**(24)**	**(26)**	(8)	(18)	(26)
Revenues	**40**	**291**	**331**	141	306	447
Expenses						
Transportation and Blending	**—**	**—**	**—**	5	—	5
Operating	**57**	**28**	**85**	117	25	142
Operating Margin [1]	**(17)**	**263**	**246**	19	281	300
Depreciation, Depletion and Amortization			**131**			128
Exploration Expense			**4**			2
(Income) Loss from Equity-Accounted Affiliates			**(10)**			(6)
Segment Income (Loss)			**121**			176

(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 March 31, 2024



Operating Results

	Three Months Ended March 31,	
	2024	2023
Sales Volumes		
Atlantic (Mbbls/d)	**3.9**	15.7
Asia Pacific (MBOE/d)		
China	**43.7**	43.0
Indonesia [1]	**14.0**	13.7
Total Asia Pacific	**57.7**	56.7
Total Sales Volumes (MBOE/d)	**61.6**	72.4
Realized Sales Price [2] ($/BOE)	**75.48**	83.64
Atlantic - Light Crude Oil ($/bbl)	**114.07**	104.98
Asia Pacific [1] ($/BOE)	**72.84**	77.71
NGLs ($/bbl)	**96.25**	96.45
Conventional Natural Gas ($/Mcf)	**11.28**	12.17
Production by Product		
Atlantic - Light Crude Oil (Mbbls/d)	**7.2**	8.9
Asia Pacific [1]		
NGLs (Mbbls/d)	**10.4**	11.4
Conventional Natural Gas (MMcf/d)	**283.4**	272.1
Total Asia Pacific (MBOE/d)	**57.7**	56.7
Total Production (MBOE/d)	**64.9**	65.6
Effective Royalty Rate [3] (percent)		
Atlantic	**4.5**	5.3
Asia Pacific [1]	**7.6**	10.2
Operating Expense [4] ($/BOE)	**17.31**	18.50
Atlantic	**158.70**	59.73
Asia Pacific [1]	**7.64**	7.05
Per-Unit DD&A [4] ($/BOE)	**29.17**	31.09

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

Revenues

Price

The price we receive for natural gas sold in Asia Pacific is set under long-term contracts. Our realized sales price on light crude oil increased in the first three months of 2024 compared with the same period in 2023, primarily due to higher Brent benchmark pricing.

Production Volumes

Atlantic production decreased 1.7 thousand barrels per day to 7.2 thousand barrels per day in the first quarter of 2024 compared with 2023, due to suspended production at the White Rose field in preparation for the planned SeaRose ALE project. The decrease was partially offset by production from the Terra Nova FPSO, which resumed in November 2023. 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 1.0 thousand BOE per day to 57.7 thousand BOE per day in the first quarter of 2024 compared with 2023, due to higher gas production in China and first gas production at the MAC field in Indonesia in September 2023. The increase was partially offset by lower NGL production in Indonesia due to the timing of condensate lifts.

Royalties

Atlantic royalties decreased to $2 million in the first quarter of 2024 from $8 million in the first quarter of 2023, primarily due to lower sales volumes.

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 months ended March 31, 2024, declined to 7.6 percent (2023 – 10.2 percent), as a result of royalty incentives for achieving production targets in Madura. The decrease was partially offset by a consumption tax implemented in China in June 2023, which impacted royalties on NGLs.

Expenses

Transportation

Transportation costs 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 costs included a nominal recovery in the first quarter of 2024 compared with 2023.

Operating

Primary drivers of our Atlantic operating expenses in the first quarter of 2024 were repairs and maintenance, and costs related to vessels and air services. Operating expenses decreased by $60 million to $57 million, primarily due to lower sales volumes, combined with a reduction of $31 million related to the restart of the West White Rose construction project during the first quarter of 2023. The decrease was partially offset by increased costs related to the SeaRose ALE project and the Terra Nova FPSO due to it resuming production in November 2023. Per-unit operating expenses increased in the first quarter of 2024 compared with 2023, mainly due to lower sales volumes offset by the decrease in overall operating expenses as discussed above.

Primary drivers of our China operating expenses in the first quarter 2024 were repairs and maintenance and insurance. Per-unit operating expenses increased by $0.70 to $6.28 per BOE, and total operating expenses increased by $3 million to $28 million, primarily due to higher repairs and maintenance in the quarter. Per-unit operating expenses associated with our Indonesian assets increased when compared with 2023, due to higher repairs and maintenance costs.

Netbacks [1]

($/BOE, except where indicated)	**Atlantic** ($/bbl)	**China**	**Indonesia** [2]	**Total Offshore**
	Three Months Ended March 31, 2024			
Sales Price	**114.07**	**79.21**	**53.05**	**75.48**
Royalties	**5.09**	**6.00**	**4.10**	**5.51**
Transportation and Blending	**(2.14)**	**—**	**—**	**(0.14)**
Operating Expenses	**158.70**	**6.28**	**11.86**	**17.31**
Netback	**(47.58)**	**66.93**	**37.09**	**52.80**

($/BOE, except where indicated)	Atlantic ($/bbl)	China	Indonesia [2]	Total Offshore
	Three Months Ended March 31, 2023			
Sales Price	104.98	83.50	59.46	83.64
Royalties	5.53	4.60	18.31	7.39
Transportation and Blending	3.16	—	—	0.69
Operating Expenses	59.73	5.58	11.69	18.50
Netback	36.56	73.32	29.46	57.06

(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. Revenues and expenses related to the HCML joint venture are accounted for using the equity method in the interim consolidated financial statements.

DOWNSTREAM

Canadian Refining

In the first quarter of 2024, we:

- Delivered safe and reliable operations.
- Had throughput of 104.1 thousand barrels per day (2023 – 98.7 thousand barrels per day), and achieved a crude utilization rate of 94 percent (2023 – 89 percent).
- Incurred higher operating expenses, primarily due to planning and preparation expenses ahead of the turnaround at the Upgrader, which will begin in the second quarter of 2024.
- Generated Operating Margin of $68 million, a decrease of $195 million compared with 2023.
- Were impacted by a 54 percent narrower Upgrading Differential of $19.31 per barrel compared with the first quarter of 2023.

Financial Results

	Three Months Ended March 31,	
($ millions)	**2024**	2023
Revenues	**1,332**	1,508
Purchased Product	**1,087**	1,093
Gross Margin [1]	**245**	415
Expenses		
Operating	**177**	152
Operating Margin	**68**	263
Depreciation, Depletion and Amortization	**44**	43
Segment Income (Loss)	**24**	220

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

Operating Results

	Three Months Ended March 31,	
	2024	2023
Total Canadian Refining		
Heavy Crude Oil Unit Throughput Capacity [(1)] (Mbbls/d)	**110.5**	110.5
Heavy Crude Oil Unit Throughput (Mbbls/d)	**104.1**	98.7
Crude Utilization (percent)	**94**	89
Total Production [(2)] (Mbbls/d)	**116.2**	112.9
Synthetic Crude Oil	**47.1**	45.7
Asphalt	**15.6**	15.8
Diesel	**12.9**	12.3
Other	**35.2**	34.0
Ethanol	**5.4**	5.1
Refining Margin [(3)] ($/bbl)	**23.69**	43.30
Per-Unit Operating Expense [(4)] ($/bbl)	**14.08**	12.46

(1) Based on crude oil name plate capacity.
(2) Includes volumes from the Upgrader, Lloydminster Refinery and the ethanol plants.
(3) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A. Revenues from the Upgrader and commercial fuels business for the three months ended March 31, 2024, was $1.1 billion (2023 – $1.2 billion). Revenue from the Lloydminster Refinery for the three months ended March 31, 2024 was $192 million (2023 – $188 million).
(4) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

	Three Months Ended March 31,	
	2024	2023
Lloydminster Upgrader		
Heavy Crude Oil Unit Throughput Capacity [(1)] (Mbbls/d)	**81.5**	81.5
Heavy Crude Oil Unit Throughput (Mbbls/d)	**75.5**	70.0
Crude Utilization (percent)	**93**	86
Production (Mbbls/d)	**82.0**	79.1
Refining Margin [(2)] ($/bbl)	**26.47**	48.53
Per-Unit Operating Expense [(3)] ($/bbl)	**14.48**	12.40
Upgrading Differential [(4)] ($/bbl)	**19.31**	41.75
Lloydminster Refinery		
Heavy Crude Oil Unit Throughput Capacity [(1)] (Mbbls/d)	**29.0**	29.0
Heavy Crude Oil Unit Throughput (Mbbls/d)	**28.6**	28.7
Crude Utilization (percent)	**99**	99
Production (Mbbls/d)	**28.8**	28.7
Refining Margin [(2)] ($/bbl)	**16.35**	30.53
Per-Unit Operating Expense [(3)] ($/bbl)	**13.03**	12.60

(1) Based on crude oil name plate capacity.
(2) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A. Revenues from the Upgrader and commercial fuels business for the three months ended March 31, 2024, was $1.1 billion (2023 – $1.2 billion). Revenue from the Lloydminster Refinery for the three months ended March 31, 2024 was $192 million (2023 – $188 million).
(3) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(4) Based on benchmark price differential between heavy oil feedstock and synthetic crude.

In the first quarter of 2024, Canadian Refining throughput increased 5.4 thousand barrels per day from the first quarter of 2023, to 104.1 thousand barrels per day, and total production increased 3.3 thousand barrels per day to 116.2 thousand barrels per day. We had high reliability at both the Upgrader and Lloydminster Refinery in 2024, compared with the Upgrader being impacted by cold weather and operational outages early in the first quarter of 2023. Utilization at the Upgrader was 93 percent (2023 – 86 percent). The Lloydminster Refinery ran at, or near, capacity in the first quarters of 2024 and 2023, with a crude utilization rate of 99 percent in both periods.

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 first quarter of 2024, approximately 13 percent of total crude oil sales volumes from our Oil Sands assets were sold to our Canadian Refining segment (2023 – 13 percent).

In the first quarter of 2024, revenues decreased by $176 million to $1.3 billion, primarily due to lower synthetic crude oil and refined product pricing, partially offset by higher production volumes. Synthetic crude oil benchmark prices decreased 11 percent to US$69.42 per barrel compared with the first quarter of 2023.

Gross margin decreased $170 million to $245 million in the first quarter of 2024 compared with 2023, primarily driven by the factors discussed above. The decrease was partially offset by the benefit of processing feedstock purchased at lower prices in prior periods.

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

Operating Expenses

Primary drivers of operating expenses in the first quarter of 2024 were workforce, and repairs and maintenance expenses.

Total operating expenses increased $25 million to $177 million for the three months ended March 31, 2024, compared with the same period in 2023, mainly due to planning and preparation expenses of $15 million ahead of the turnaround at the Upgrader, which will begin in the second quarter of 2024.

Per-unit operating expenses are calculated as the operating expenses associated with the Upgrader and the Lloydminster Refinery, divided by crude oil unit throughput. Per-unit operating expenses increased $1.62 per barrel to $14.08 per barrel in the first quarter of 2024, primarily due to higher operating expenses discussed above.

U.S. Refining

In the first quarter of 2024, we:

- Achieved crude utilization of 87 percent, compared with 67 percent in the first quarter of 2023.
- Generated an Operating Margin of $492 million, an increase of $364 million from the first quarter of 2023.
- Realized the benefit from the Toledo Acquisition, which has allowed us to better use existing resources across our U.S. portfolio to improve our product mix.
- Produced 585.9 thousand barrels per day of refined product (2023 – 374.8 thousand barrels per day). The increase was primarily due to operations at the Toledo and Superior refineries.
- Invested capital of $67 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 March 31,	
($ millions)	**2024**	2023
Revenues [(1)]	**7,235**	5,629
Purchased Product [(1)]	**6,132**	4,898
Gross Margin [(2)]	**1,103**	731
Expenses		
Operating	**610**	602
Realized (Gain) Loss on Risk Management	**1**	1
Operating Margin	**492**	128
Unrealized (Gain) Loss on Risk Management	**8**	(6)
Depreciation, Depletion and Amortization	**111**	103
Segment Income (Loss)	**373**	31

(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. See the Specified Financial Measures Advisory of this MD&A.*

Operating Results - Consolidated

	Three Months Ended March 31,	
	2024	2023
Total U.S. Refining		
Crude Oil Unit Throughput Capacity [1] [2] (Mbbls/d)	**635.2**	635.2
Crude Oil Unit Throughput [2] (Mbbls/d)	**551.1**	359.2
Heavy Crude Oil	**224.7**	114.7
Light and Medium Crude Oil	**326.4**	244.5
Crude Utilization [2] (percent)	**87**	67
Total Production (Mbbls/d)	**585.9**	374.8
Gasoline	**281.9**	187.1
Distillates [3]	**200.1**	138.1
Asphalt	**26.1**	10.8
Other	**77.8**	38.8
Refining Margin [4] ($/bbl)	**22.00**	22.62
Per-Unit Operating Expense [5] ($/bbl)	**12.16**	18.63

(1) Based on crude oil name plate capacity.
(2) The Superior Refinery's crude oil unit throughput and crude oil unit throughput capacity are included in the crude utilization calculation effective April 1, 2023. The Toledo Refinery's crude utilization includes a weighted average crude oil capacity with full ownership acquired on February 28, 2023.
(3) Includes diesel and jet fuel.
(4) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(5) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

Operating Results - by Refinery

	Three Months Ended March 31,							
	2024				2023			
	Lima	**Toledo**	**Superior**	**Wood River and Borger** [1]	Lima	Toledo	Superior	Wood River and Borger [1]
Crude Oil Unit Throughput Capacity [2] (Mbbls/d)	**178.7**	**160.0**	**49.0**	**247.5**	178.7	160.0	49.0	247.5
Crude Oil Unit Throughput (Mbbls/d)	**152.4**	**133.0**	**32.2**	**233.4**	167.2	—	0.2	191.8
Crude Utilization [3] (percent)	**85**	**83**	**66**	**94**	94	—	—	77

(1) Represents Cenovus's 50 percent interest in the non-operated Wood River and Borger refinery operations.
(2) Based on crude oil name plate capacity.
(3) The Superior Refinery's crude oil unit throughput and crude oil unit throughput capacity are included in the crude utilization calculation effective April 1, 2023. The Toledo Refinery's crude utilization includes a weighted average crude oil capacity with full ownership acquired on February 28, 2023.

In the three months ended March 31, 2024, U.S. Refining throughput increased 191.9 thousand barrels per day from the three months ended March 31, 2023, to 551.1 thousand barrels per day, and total refined product production increased 211.1 thousand barrels per day to 585.9 thousand barrels per day. These increases primarily related to a full quarter of production at both the Toledo Refinery and the Superior Refinery. Other factors that impacted total throughput and total refined product production compared with the first quarter of 2023 include:

- Increased throughput and refined product production at the Wood River and Borger refineries due to favourable market conditions since the end of January, combined with unplanned outages and planned turnarounds at both refineries in the first quarter of 2023. Combined crude utilization was 94 percent in the quarter (2023 – 77 percent).
- Unplanned outages at the Lima Refinery that decreased throughput 14.8 thousand barrels per day compared with the first quarter of 2023, to 152.4 thousand barrels per day.
- A planned third-party hydrogen outage that impacted throughput at the Toledo Refinery.
- An unplanned outage caused by a line freeze that reduced throughput and production at the Superior Refinery in January. The refinery restarted in mid-February, but continued to run at reduced rates to manage inventory.
- Flexed throughput at our U.S. refineries to optimize our margins due to significantly lower benchmark prices early in the quarter.

Revenues and Gross Margin

Market crack spreads do not precisely mirror the configuration and product output of our refineries; however, they are used as a general market indicator. The Chicago 3-2-1 market crack spread reflects the market for the Toledo, Lima and Wood River refineries. The Group 3 3-2-1 market crack spread reflects the market for the Superior and Borger refineries. 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.

For the three months ended March 31, 2024, the Chicago 3-2-1 crack spread decreased 40 percent to US$17.45 per barrel compared with 2023, and the Group 3 crack spread decreased 44 percent to US$17.50 per barrel compared with 2023. The Chicago 3-2-1 crack spread averaged US$5.56 in January and increased to an average of US$25.06 in March. Average benchmark gasoline prices fell 10 percent to US$89.48 per barrel in the first quarter of 2024 compared with 2023. Average benchmark diesel prices also fell US$11.12 per barrel to US$104.27 per barrel in the first quarter of 2024 compared with the same period in 2023.

Revenues increased $1.6 billion in the first quarter of 2024 compared with 2023, primarily due to the restart of the Toledo and Superior refineries discussed above, combined with higher utilization at the Wood River and Borger refineries, partially offset by lower refined product pricing. Gross margin increased $372 million in the first quarter of 2024 compared with the first quarter of 2023, primarily due to the reasons discussed above, the benefits from weaker RINs pricing (US$3.68 per barrel in the first quarter of 2024 compared with US$8.20 per barrel in the first quarter of 2023) and the benefits from processing feedstock purchased at lower prices in prior periods.

Operating Expenses

Primary drivers of operating expenses in the first quarter of 2024 were workforce and repairs and maintenance.

Operating expenses increased $8 million to $610 million in the first quarter of 2024, primarily driven by an increase in workforce costs and repairs and maintenance costs. The first quarter 2023 results reflect our 100 percent ownership of the Toledo Refinery from February 28 onward. Other factors impacting operating expenses include:

- Higher repairs and maintenance costs related to an unplanned outage at the Lima Refinery and repairs on the line freeze at the Superior Refinery.
- Planned maintenance at the Toledo Refinery.
- Costs related to planning and preparation expenses ahead of the turnaround at the Lima Refinery scheduled to begin in the third quarter of 2024.

The increase was partially offset by lower spend on safety supplies and start-up expenses in the first quarter of 2024. These costs were higher in the same period of 2023 due to the restart of the Toledo and Superior refineries. The increase was also partially offset as both the Wood River and Borger refineries had turnarounds in the first quarter of 2023.

In the first quarter of 2024, per-unit operating expenses decreased $6.47 per barrel to $12.16 per barrel, as the increases in operating expenses discussed above were offset by higher throughput in the first quarter of 2024. The increase in crude oil unit throughput was due in part to the Toledo Refinery and the Superior Refinery not having throughput in the comparative period.

(Gain) Loss on Risk Management

In the first quarter of 2024, we incurred realized risk management losses of $1 million (2023 – $1 million) due to the settlement of benchmark prices relative to our risk management contract prices. In the first quarter of 2024, we recorded unrealized risk management losses of $8 million (2023 – gains of $6 million), on our crude oil and refined products financial instruments primarily due to changes to forward benchmark pricing relative to our risk management contract prices that relate to future periods.

CORPORATE AND ELIMINATIONS

Financial Results

($ millions)	Three Months Ended March 31, 2024	2023
Realized (Gain) Loss on Risk Management	**3**	7
Unrealized (Gain) Loss on Risk Management	**30**	30
General and Administrative	**246**	158
Finance Costs, Net [(1)]	**135**	161
Integration, Transaction and Other Costs	**33**	20
Foreign Exchange (Gain) Loss, Net	**99**	(7)
(Gain) Loss on Divestiture of Assets [(1)]	**(105)**	32
Re-measurement of Contingent Payments	**28**	17
Other (Income) Loss, Net	**(90)**	(6)

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

Risk Management

For the three months ended March 31, 2024, our corporate risk management activities resulted in realized risk management losses related to foreign exchange risk management contracts. Unrealized risk management losses were primarily related to renewable power contracts.

General and Administrative

Primary drivers of our general and administrative expenses in the first quarter of 2024 were employee long-term incentive costs, workforce costs and information technology costs. General and administrative expenses increased in the first quarter of 2024 compared with 2023, primarily due to non-cash stock-based compensation costs of $101 million (2023 –$16 million).

Finance Costs, Net

Finance costs were lower in the three months ended March 31, 2024, compared with the three months ended March 31, 2023, due to lower interest expense as a result of the Company's lower long-term debt. In the third quarter of 2023, we purchased long-term debt with an aggregate principal amount of US$1.0 billion. 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 months ended March 31, 2024 was 4.47 percent (2023 – 4.74 percent).

Integration, Transaction and Other Costs

We incurred costs of $33 million related to modernizing and replacing certain information technology systems, optimizing business processes and standardizing data across the Company. In the first quarter of 2023, we incurred integration and transaction costs of $20 million, related to the Toledo Acquisition.

Foreign Exchange (Gain) Loss, Net

($ millions)	Three Months Ended March 31, 2024	2023
Unrealized Foreign Exchange (Gain) Loss	**124**	14
Realized Foreign Exchange (Gain) Loss	**(25)**	(21)
	99	(7)

For the three months ended March 31, 2024, unrealized foreign exchange losses were mainly related to the translation of U.S. denominated debt caused by a weaker Canadian dollar as at March 31, 2024, than at December 31, 2023. Realized foreign exchange gains in the first quarters of 2024 and 2023 were primarily related to working capital.

(Gain) Loss on Divestiture of Assets

For the three months ended March 31, 2024, we recorded gains on asset divestitures of $105 million (2023 – loss of $32 million). On February 6, 2024, we closed a transaction with Athabasca Oil Corporation ("Athabasca") to create Duvernay Energy Corporation ("Duvernay"), 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 March 31, 2024, the fair value of the remaining variable payment was estimated to be $142 million, resulting in non-cash re-measurement losses of $28 million in the three months ended March 31, 2024 (2023 – $17 million).

For the three months ended March 31, 2024, we paid $107 million under this agreement, for the quarter ended November 30, 2023 (2023 – $92 million). The payment of $50 million for the quarter ended February 29, 2024, was made on April 29, 2024. The payments are recognized in cash from (used in) investing activities. As at March 31, 2024, the average estimated WCS forward pricing for the remaining term of the variable payment was $91.98 per barrel. The maximum payment over the remaining term of the contract is $144 million.

Other (Income) Loss, Net

In the first three months of 2024, other income was $90 million compared with $6 million in the same period of 2023, primarily due to the receipt of insurance proceeds related to business interruption at the Toledo Refinery.

Depreciation, Depletion & Amortization

DD&A for the three months ended March 31, 2024, was $25 million, compared with $21 million in for the three months ended March 31, 2023.

Income Taxes

	Three Months Ended March 31,	
($ millions)	**2024**	2023
Current Tax		
Canada	**346**	258
United States	**11**	17
Asia Pacific	**44**	46
Other International	**9**	6
Total Current Tax Expense (Recovery)	**410**	327
Deferred Tax Expense (Recovery)	**(32)**	(370)
	378	(43)

The increase in current income tax expense for the first quarter of 2024 was due to higher earnings compared with the same period in 2023. The effective tax rate in 2024 was 24.3 percent (2023 – negative 7.3 percent). The first quarter 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 Investor Service, Morningstar DBRS and Fitch Ratings. In the first quarter of 2024, we received a rating upgrade from S&P Global to BBB with a Stable outlook. The cost and availability of borrowing and access to sources of liquidity and capital are dependent on current credit ratings and market conditions.

	Three Months Ended March 31,	
($ millions)	**2024**	2023
Cash From (Used In)		
Operating Activities	**1,925**	(286)
Investing Activities	**(1,135)**	(1,755)
Net Cash Provided (Used) Before Financing Activities	**790**	(2,041)
Financing Activities	**(677)**	(435)
Effect of Foreign Exchange on Cash and Cash Equivalents	**60**	1
Increase (Decrease) in Cash and Cash Equivalents	**173**	(2,475)

As at ($ millions)	**March 31, 2024**	December 31, 2023
Cash and Cash Equivalents	**2,400**	2,227
Total Debt	**7,227**	7,287

Cash From (Used in) Operating Activities

For the three months ended March 31, 2024, cash from operating activities was $1.9 billion, compared with a use of cash of $286 million during the same period in 2023. The increase was primarily due to higher Operating Margin and changes in non-cash working capital. In the first quarter of 2024, changes in non-cash working capital decreased cash by $269 million from December 31, 2023. The decrease was primarily driven by higher accounts receivable, accounts payable and inventory due to higher crude oil and refined product pricing. In the first quarter of 2023, changes in non-cash working capital decreased cash by $1.6 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 decreased in the first quarter of 2024 compared with the same period in 2023. The decrease was primarily due to a decrease in acquisition capital. Acquisition capital was higher in 2023 as we closed the Toledo Acquisition in the first quarter. The net change in non-cash working capital from investing activities was $101 million, compared with $184 million in 2023. The changes were primarily driven by fluctuations in the amount due under the contingent payment.

Cash From (Used in) Financing Activities

For the three months ended March 31, 2024, cash used in financing activities increased compared with the same period in 2023, primarily due to increased cash returns to shareholders of $436 million compared with $258 million in the first quarter of 2023, combined with an increase in the repayment of short-term borrowings.

Working Capital

Excluding the current portion of the contingent payments, our adjusted working capital at March 31, 2024, was $4.6 billion (December 31, 2023 – $3.7 billion). The increase in working capital was driven by an increase in accounts receivable, inventory and accounts payable, primarily due to higher commodity prices. Total inventory volumes decreased relative to December 31, 2023.

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

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

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

	Three Months Ended March 31,	
($ millions)	**2024**	2023
Cash From (Used in) Operating Activities	**1,925**	(286)
(Add) Deduct:		
Settlement of Decommissioning Liabilities	**(48)**	(48)
Net Change in Non-Cash Working Capital	**(269)**	(1,633)
Adjusted Funds Flow	**2,242**	1,395
Capital Investment	**1,036**	1,101
Free Funds Flow	**1,206**	294
Add (Deduct):		
Base Dividends Paid on Common Shares	**(262)**	(200)
Dividends Paid on Preferred Shares	**(9)**	(18)
Settlement of Decommissioning Liabilities	**(48)**	(48)
Principal Repayment of Leases	**(70)**	(70)
Acquisitions, Net of Cash Acquired	**(10)**	(465)
Proceeds From Divestitures	**25**	8
Excess Free Funds Flow	**832**	(499)

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.

Currently, we plan to return incremental value to shareholders through share buybacks and/or variable dividends as follows:

- When Net Debt is less than $9.0 billion and above $4.0 billion at quarter-end, we will target to allocate 50 percent of the following quarter's Excess Free Funds Flow to shareholder returns, while still continuing to deleverage the balance sheet until we reach the Net Debt target of $4.0 billion.
- When Net Debt is above $9.0 billion at quarter-end, we will target to allocate 100 percent of the following quarter's Excess Free Funds Flow to deleveraging the balance sheet.

To increase clarity and predictability of returns to shareholders once we achieve our Net Debt target at a quarter's end, we will thereafter 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 by which 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 December 31, 2023, our long-term debt was $7.1 billion, and our Net Debt position was $5.1 billion. Therefore, our returns to shareholders target for the three months ended March 31, 2024, was 50 percent of the current quarter's Excess Free Funds Flow of $832 million. Our target return was $416 million, which was partially met through share buybacks of $165 million. As such, the Board of Directors declared a second quarter variable dividend of $0.135 per common share, payable on May 31, 2024, to common shareholders of record as at May 17, 2024.

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

As at March 31, 2024, our Net Debt position was $4.8 billion and as a result, our returns to shareholders target for the three months ended June 30, 2024, will be 50 percent of the second quarter's Excess Free Funds Flow.

Short-Term Borrowings

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

Long-Term Debt, Including Current Portion

Long-term debt, including the current portion, as at March 31, 2024, was $7.2 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 March 31, 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 March 31, 2024:

($ millions)	Maturity	Amount Available
Cash and Cash Equivalents	**n/a**	**2,400**
Committed Credit Facility [(1)]		
Revolving Credit Facility – Tranche A	**November 10, 2026**	**3,700**
Revolving Credit Facility – Tranche B	**November 10, 2025**	**1,800**
Uncommitted Demand Facilities		
Cenovus Energy Inc. [(2)]	**n/a**	**1,127**
WRB [(3)]	**n/a**	**305**

(1) No amounts were drawn on the committed credit facility as at March 31, 2024 (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 March 31, 2024, there were outstanding letters of credit aggregating to $308 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 March 31, 2024, $nil of this capacity was drawn (December 31, 2023 – US$135 million (C$179 million)).

Under the terms of our committed credit facility, we are required to maintain a debt to capitalization ratio, as defined in the debt agreements, not to exceed 65 percent. We are 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	**March 31, 2024**	December 31, 2023
Net Debt to Adjusted EBITDA Ratio (times)	**0.4**	0.5
Net Debt to Adjusted Funds Flow Ratio (times)	**0.5**	0.6
Net Debt to Capitalization Ratio (percent)	**14**	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 March 31, 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 March 31, 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 March 31, 2024, there were approximately 1,865.2 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 March 31, 2024, there were approximately 7.3 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 April 26, 2024	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**1,860,254**	**n/a**
Cenovus Warrants	**7,280**	**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	**13,364**	**8,995**
Other Stock-Based Compensation Plans	**17,485**	**1,732**

Common Share Dividends

In the first quarter of 2024, we paid base dividends of $262 million or $0.140 per common share (2023 – $200 million or $0.105 per common share).

On April 30, 2024, the Board of Directors declared a second quarter base dividend of $0.180 per common share, an increase of 29 percent from the first quarter dividend declared in February 2024. The dividend is payable on June 28, 2024, to common shareholders of record as at June 14, 2024. The increase is aligned with our long-term value proposition and our plans to sustainably grow our base dividend.

The Board of Directors declared a second quarter variable dividend of 0.135 per common share, payable on May 31, 2024, to common shareholders of record as at May 17, 2024. No variable dividend was declared or paid in the first quarter of 2024 or 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 months ended March 31, 2024, dividends of $9 million were paid on the series 1, 2, 3, 5 and 7 preferred shares (2023 – $18 million). The Board declared a second quarter dividend on the series 1, 2, 3, 5 and 7 preferred shares for a total of $9 million, payable on July 2, 2024, to preferred shareholders of record as at June 14, 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 March 31,	
	2024	2023
Common Shares Purchased and Cancelled Under NCIB (millions of common shares)	**7.4**	1.6
Weighted Average Price per Common Share ($)	**22.30**	25.54
Purchase of Common Shares Under NCIB ($ millions)	**(165)**	(40)

From April 1, 2024, to April 26, 2024, the Company purchased an additional 8.6 million common shares for $250 million. As at April 26, 2024, the Company can further purchase up to 106.6 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. For further information, see Note 23 to the interim Consolidated Financial Statements.

Our total commitments were $28.7 billion as at March 31, 2024 (December 31, 2023 – $28.8 billion), of which $25.0 billion are for various transportation and storage commitments, and $380 million are for product purchase commitments. Transportation commitments include $13.6 billion 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 March 31, 2024, our total commitments included commitments with HMLP of $2.0 billion related to long-term transportation and storage commitments.

As at March 31, 2024, outstanding letters of credit issued as security for performance under certain contracts totaled $308 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 three months ended March 31, 2024, the Company received $31 million of distributions from HCML (2023 – $23 million) and paid $nil in contributions (2023 – $11 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 three months ended March 31, 2024, we charged HMLP $31 million for construction and management services (2023 – $32 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 three months ended March 31, 2024, we incurred costs of $69 million for the use of HMLP's pipeline systems, as well as for transportation and storage services (2023 – $67 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.

The following presentation changes were made and comparative periods were 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 International Accounting Standards Board issued IFRS 18, *"Presentation and Disclosure in Financial Statements"* 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.

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 March 31, 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 March 31, 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", "forecast", "may", "objective", "opportunities", "plan", "position", "prioritize", "progress", "strive", "target", and "will", or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: shareholder value and returns; safety; sustainability; maximizing value; financial discipline; disciplined capital allocation; Free Funds Flow; managing our balance sheet; growth of our base business; our 2024 capital investment budget; reducing costs; realizing the full value of our integrated business; reinvesting in our business; diversifying our portfolio; Net Debt; production at Terra Nova; resuming production at the White Rose field; first oil from the West White Rose project; enhancing U.S. refining profitability; optimizing run rates at the Company's refineries; project execution; reliable operations; being best in class operators; maintaining a strong balance sheet; executing major projects; turnaround activity and expenses; physical integration; costs; margins; realizing the full value of our integrated business; long term value for Cenovus; downstream reliability and profitability; our five ESG focus areas; Pathways Alliance carbon transportation network and storage hub project; 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; Net Debt to Capitalization 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 dispositions, including with desired transaction metrics and within expected timelines; the accuracy of climate scenarios and assumptions, including third party data on which the Company relies; ability to access and implement all technology and equipment necessary to achieve expected future results, including in respect of climate and GHG emissions targets and ambitions and the commercial viability and scalability of emission reduction strategies and related technology and products; collaboration with the government, Pathways Alliance and other industry organizations; alignment of realized WCS and WCS prices used to calculate the variable payment to bp Canada; market and business conditions; forecast inflation and other assumptions inherent in the Company's 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 December 13, 2023, and available on cenovus.com, assumes: Brent prices of US$79.00 per barrel, WTI prices of US$75.00 per barrel; WCS of US$58.00 per barrel; Differential WTI-WCS of US$17.00 per barrel; AECO natural gas prices of $2.80 per Mcf; Chicago 3-2-1 crack spread of US$21.00 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 dispositions; the Company's ability to access or implement some or all of the technology necessary to efficiently and effectively operate its assets and achieve expected future results including in respect of climate and GHG emissions targets and ambitions and the commercial viability and scalability of emission reduction strategies and related technology and products; the development and execution of implementing strategies to meet climate and GHG emissions targets and ambitions; the effect of new significant shareholders; volatility of and other assumptions regarding commodity prices; the duration of any market downturn; foreign exchange risk, including related to agreements denominated in foreign currencies; the Company's continued liquidity being sufficient to sustain operations through a prolonged market downturn; WTI-WCS differential will remain largely tied to global supply factors and heavy crude processing capacity; the Company's ability to realize the expected impacts of its capacity to store within its oil sands reservoirs barrels not yet produced, including possible inability to time production and sales at later dates when pipeline and/or storage capacity and crude oil differentials have improved; the effectiveness of the Company's risk management program; the accuracy of cost estimates regarding commodity prices, currency and interest rates; lack of alignment of realized WCS prices and WCS prices used to recalculate the variable payment to bp Canada; product supply and demand; the accuracy of the Company's share price and market capitalization assumptions; market competition, including from alternative energy sources; risks inherent in the Company's marketing operations, including credit risks, exposure to counterparties and partners, including the ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in the operation of the Company's crude-by-rail terminal, including health, safety and environmental risks; the Company's ability to maintain desirable ratios of Net Debt to Adjusted EBITDA and Net Debt to Adjusted Funds Flow; the Company's ability to access various sources of debt and equity capital, generally, and on acceptable terms; the Company's ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to the Company or any of its securities; changes to the Company's dividend plans; the Company's ability to utilize tax losses in the future; the accuracy of the Company's reserves, future production and future net revenue estimates; the accuracy of the Company's accounting estimates and judgements; the Company's ability to replace and expand crude oil and natural gas reserves; the costs to acquire exploration rights, undertake geological studies, appraisal drilling and project developments; potential requirements under applicable accounting standards for impairment or reversal of estimated recoverable amounts of some or all of the Company's assets or goodwill from time to time; the Company's ability to maintain its relationships with its partners and to successfully manage and operate its integrated operations and business; reliability of the Company's assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and Refining processes; the occurrence of unexpected events resulting in operational interruptions, including at facilities operated by our partners or third parties, such as blowouts, fires, explosions, railcar incidents or derailments, aviation incidents, iceberg collisions, gaseous leaks, migration of harmful substances, loss of containment, releases or spills, including releases or spills from offshore facilities and shipping vessels at terminals or hubs and as a result of pipeline or other leaks, corrosion, epidemics or pandemics, and catastrophic events, including, but not limited to, war, adverse sea conditions, extreme weather events, natural disasters, acts of activism, vandalism and terrorism, and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites and other accidents or similar events; refining and marketing margins; cost escalations, including inflationary pressures on operating costs, such as labour, materials, natural gas and other energy sources used in oil sands processes and downstream operations and increased insurance deductibles or premiums; the cost and availability of equipment necessary to the Company's operations; potential failure of products to achieve or maintain acceptance in the market; risks associated with the energy industry's and the Company's reputation, social license to operate and litigation related thereto; unexpected cost increases or technical difficulties in operating, constructing or modifying 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

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, 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, and Excess Free Funds Flow, for prior period information from 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 March 31,					
	2024	2023	**2024**	2023	**2024**	2023
($ millions)	**Upstream** [1]		**Downstream** [1]		**Total**	
Gross Sales [2]	**7,864**	7,217	**8,567**	7,137	**16,431**	14,354
Royalties	**(747)**	(596)	**—**	—	**(747)**	(596)
Revenues	**7,117**	6,621	**8,567**	7,137	**15,684**	13,758
Expenses						
Purchased Product [2]	**771**	838	**7,219**	5,991	**7,990**	6,829
Transportation and Blending [2]	**2,811**	3,027	**—**	—	**2,811**	3,027
Operating	**898**	1,029	**787**	754	**1,685**	1,783
Realized (Gain) Loss on Risk Management	**6**	16	**1**	1	**7**	17
Operating Margin	**2,631**	1,711	**560**	391	**3,191**	2,102

(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 March 31, 2024		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore** [1]
Gross Sales	**42**	**315**	**357**
Royalties	**(2)**	**(24)**	**(26)**
Revenues	**40**	**291**	**331**
Expenses			
Transportation and Blending	**—**	**—**	**—**
Operating	**57**	**28**	**85**
Operating Margin	**(17)**	**263**	**246**

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

	Three Months Ended March 31, 2023		
($ millions)	Atlantic	Asia Pacific	Offshore [1]
Gross Sales	149	324	473
Royalties	(8)	(18)	(26)
Revenues	141	306	447
Expenses			
Transportation and Blending	5	—	5
Operating	117	25	142
Operating Margin	19	281	300

(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.

	Three Months Ended March 31,	
($ millions)	**2024**	2023
Cash From (Used in) Operating Activities	**1,925**	(286)
(Add) Deduct:		
Settlement of Decommissioning Liabilities	**(48)**	(48)
Net Change in Operating Non-Cash Working Capital	**(269)**	(1,633)
Adjusted Funds Flow	**2,242**	1,395
Capital Investment	**1,036**	1,101
Free Funds Flow	**1,206**	294
Add (Deduct):		
Base Dividends Paid on Common Shares	**(262)**	(200)
Dividends Paid on Preferred Shares	**(9)**	(18)
Settlement of Decommissioning Liabilities	**(48)**	(48)
Principal Repayment of Leases	**(70)**	(70)
Acquisitions, Net of Cash Acquired	**(10)**	(465)
Proceeds From Divestitures	**25**	8
Excess Free Funds Flow	**832**	(499)

Gross Margin and Refining Margin

Gross Margin and Refining Margin are non-GAAP financial measures, or contain a non-GAAP financial measure, used to evaluate the performance of our downstream operations. We define Gross Margin as revenues less purchased product. We define Refining Margin as Gross Margin from our refineries and Upgrader divided by crude oil unit throughput.

Canadian Refining

($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other (1)	Total Canadian Refining (2)
	Three Months Ended March 31, 2024				
Revenues	1,079	192	1,271	61	1,332
Purchased Product	897	150	1,047	40	1,087
Gross Margin	182	42	224	21	245

	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
	Operating Statistics		
Heavy Crude Oil Unit Throughput (Mbbls/d)	75.5	28.6	104.1
Refining Margin ($/bbl)	26.47	16.35	23.69

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

($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other (1)	Total Canadian Refining (2)
	Three Months Ended March 31, 2023				
Revenues	1,213	188	**1,401**	107	**1,508**
Purchased Product	907	109	**1,016**	77	**1,093**
Gross Margin	306	79	**385**	30	**415**

	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
	Operating Statistics		
Heavy Crude Oil Unit Throughput (Mbbls/d)	70.0	28.7	98.7
Refining Margin ($/bbl)	48.53	30.53	43.30

(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.

U.S. Refining

($ millions)	Three Months Ended March 31, 2024	2023
Revenues (1) (2)	**7,235**	5,629
Purchased Product (1) (2)	**6,132**	4,898
Gross Margin	**1,103**	731
Crude Oil Unit Throughput (Mbbls/d)	**551.1**	359.2
Refining Margin ($/bbl)	**22.00**	22.62

(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.

Per-Unit Operating Expenses

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 and Lloydminster Refinery, divided by crude oil unit throughput. We define U.S. Refining Per-Unit Operating Expenses as operating expenses divided by crude oil unit throughput. Our Upstream Per-Unit Operating Expenses 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 Expense

Per-Unit Transportation Expense is a specified financial measure used to measure transportation expenses on a per-unit basis in our upstream segments. We define Per-Unit Transportation Expense as the total transportation expenses divided by sales volumes. Our Upstream Per-Unit Transportation Expense is part of our Netback calculation, which can be found below.

Netback Reconciliations and Realized Sales Price

Netback per barrel of oil equivalent is a non-GAAP ratio. 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. Netbacks per BOE reflect our margin on a per-barrel of oil equivalent basis. Netback is defined as gross sales less royalties, transportation and blending and operating expenses. Realized sales price is a non-GAAP financial measure. It includes our realized sales, purchased diluent costs and profit from optimization activities, such as cogeneration, third-party processing and trading. Per-unit measures are divided by sales volumes. Netbacks do not reflect non-cash write-downs or reversals of product inventory until it is realized when the product is sold and exclude risk management activities. 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.

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

Oil Sands

	Basis of Netback Calculation						
Three Months Ended March 31, 2024 ($ millions)	Foster Creek	Christina Lake	Sunrise	Lloydminster Oil Sands [1]	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
Gross Sales	1,356	1,474	340	850	**4,020**	—	**4,020**
Royalties	(293)	(339)	(11)	(54)	**(697)**	—	**(697)**
Revenues	1,063	1,135	329	796	**3,323**	—	**3,323**
Expenses							
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	181	119	71	45	**416**	—	**416**
Operating	191	188	65	211	**655**	—	**655**
Netback	691	828	193	540	**2,252**	—	**2,252**
Realized (Gain) Loss on Risk Management							**13**
Operating Margin							**2,239**

	Basis of Netback Calculation	Adjustments			
Three Months Ended March 31, 2024 ($ millions)	Total Oil Sands	Condensate	Third-party Sourced	Other [2]	Total Oil Sands [3]
Gross Sales	**4,020**	2,305	213	90	**6,628**
Royalties	**(697)**	—	—	—	**(697)**
Revenues	**3,323**	2,305	213	90	**5,931**
Expenses					
Purchased Product	**—**	—	213	76	**289**
Transportation and Blending	**416**	2,305	—	12	**2,733**
Operating	**655**	—	—	5	**660**
Netback	**2,252**	—	—	(3)	**2,249**
Realized (Gain) Loss on Risk Management	**13**	—	—	—	**13**
Operating Margin	**2,239**	—	—	(3)	**2,236**

Three Months Ended March 31, 2023 ($ millions)	Foster Creek	Christina Lake	Sunrise	Lloydminster Oil Sands (1)	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
	Basis of Netback Calculation						
Gross Sales	1,032	1,067	181	605	**2,885**	3	**2,888**
Royalties	(189)	(273)	(6)	(47)	**(515)**	(1)	**(516)**
Revenues	843	794	175	558	**2,370**	2	**2,372**
Expenses							
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	222	165	45	38	**470**	—	**470**
Operating	215	195	79	236	**725**	4	**729**
Netback	406	434	51	284	**1,175**	(2)	**1,173**
Realized (Gain) Loss on Risk Management							**7**
Operating Margin							**1,166**

Three Months Ended March 31, 2023 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	**Condensate**	**Third-party Sourced**	**Other (2)**	**Total Oil Sands (3) (4)**
Gross Sales	**2,888**	2,445	294	80	**5,707**
Royalties	**(516)**	—	—	—	**(516)**
Revenues	**2,372**	2,445	294	80	**5,191**
Expenses					
Purchased Product	**—**	—	294	61	**355**
Transportation and Blending	**470**	2,445	—	26	**2,941**
Operating	**729**	—	—	8	**737**
Netback	**1,173**	—	—	(15)	**1,158**
Realized (Gain) Loss on Risk Management	**7**	—	—	1	**8**
Operating Margin	**1,166**	—	—	(16)	**1,150**

(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 March 31, 2024 ($ millions)	Basis of Netback Calculation	Adjustments		
	Conventional	**Third-party Sourced**	**Other (1)**	**Conventional (2)**
Gross Sales	**362**	482	35	**879**
Royalties	**(24)**	—	—	**(24)**
Revenues	**338**	482	35	**855**
Expenses				
Purchased Product	**—**	482	—	**482**
Transportation and Blending	**51**	—	27	**78**
Operating	**143**	—	10	**153**
Netback	**144**	—	(2)	**142**
Realized (Gain) Loss on Risk Management	**(7)**	—	—	**(7)**
Operating Margin	**151**	—	(2)	**149**

Three Months Ended March 31, 2023 ($ millions)	Basis of Netback Calculation	Adjustments		
	Conventional	**Third-party Sourced**	**Other (1)**	**Conventional (2) (3)**
Gross Sales	**491**	483	63	**1,037**
Royalties	**(54)**	—	—	**(54)**
Revenues	**437**	483	63	**983**
Expenses				
Purchased Product	**—**	483	—	**483**
Transportation and Blending	**45**	—	36	**81**
Operating	**146**	—	4	**150**
Netback	**246**	—	23	**269**
Realized (Gain) Loss on Risk Management	**8**	—	—	**8**
Operating Margin	**238**	—	23	**261**

(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 March 31, 2024 ($ millions)	Basis of Netback Calculation: Atlantic	China	Indonesia [1]	Total Asia Pacific	Total Offshore	Adjustments: Equity Adjustment [1]	Other	Total Offshore [3]
Gross Sales	42	315	68	**383**	**425**	(68)	—	**357**
Royalties	(2)	(24)	(5)	**(29)**	**(31)**	5	—	**(26)**
Revenues	40	291	63	**354**	**394**	(63)	—	**331**
Expenses								
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	—	—	—	**—**	**—**	—	—	**—**
Operating	57	25	15	**40**	**97**	(12)	—	**85**
Netback	(17)	266	48	**314**	**297**	(51)	—	**246**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**297**	(51)	—	**246**

Three Months Ended March 31, 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	149	324	73	**397**	**546**	(73)	—	**473**
Royalties	(8)	(18)	(23)	**(41)**	**(49)**	23	—	**(26)**
Revenues	141	306	50	**356**	**497**	(50)	—	**447**
Expenses								
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	5	—	—	**—**	**5**	—	—	**5**
Operating	85	22	14	**36**	**121**	(10)	31	**142**
Netback	51	284	36	**320**	**371**	(40)	(31)	**300**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**371**	(40)	(31)	**300**

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

Upstream Sales Volumes [1]

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

(MBOE/d)	Three Months Ended March 31, 2024	2023
Oil Sands		
Foster Creek	**194.0**	183.6
Christina Lake	**242.2**	237.9
Sunrise	**42.3**	39.8
Lloydminster	**128.4**	115.7
Total Oil Sands	**606.9**	577.0
Conventional	**120.7**	123.9
Offshore		
Atlantic	**3.9**	15.7
Asia Pacific		
China	**43.7**	43.0
Indonesia	**14.0**	13.7
Total Asia Pacific	**57.7**	56.7
Total Offshore	**61.6**	72.4
Sales Before Internal Consumption	**789.2**	773.3
Internal Consumption [2]	**(105.8)**	(90.2)
Total Upstream Sales	**683.4**	683.1

(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 March 31, 2023		
($ millions)	Previously Reported	Revisions	Revised Balance
Oil Sands Segment			
Gross Sales	5,911	(204)	**5,707**
Purchased Product	559	(204)	**355**
	5,352	—	**5,352**
Conventional Segment			
Gross Sales	1,031	6	**1,037**
Purchased Product	510	(27)	**483**
Transportation and Blending	48	33	**81**
	473	—	**473**
U.S. Refining Segment			
Gross Sales	5,860	(231)	**5,629**
Purchased Product	5,129	(231)	**4,898**
	731	—	**731**
Corporate and Eliminations Segment			
Gross Sales	(1,925)	429	**(1,496)**
Purchased Product	(1,499)	479	**(1,020)**
Transportation and Blending	(141)	(134)	**(275)**
Operating	(231)	84	**(147)**
	(54)	—	**(54)**
Consolidated			
Purchased Product	5,792	17	**5,809**
Transportation and Blending	2,853	(101)	**2,752**
Purchased Product, Transportation and Blending (1)	8,645	(84)	**8,561**
Operating	1,552	84	**1,636**
	10,197	—	**10,197**

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