Cenovus Energy Inc.

Management's Discussion and Analysis (unaudited)

For the Year Ended December 31, 2023

(Canadian Dollars)

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the year ended December 31, 2023

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", the "Company", or "Cenovus", and means Cenovus Energy Inc., the subsidiaries of, joint arrangements, and partnership interests held directly or indirectly by, Cenovus Energy Inc.) dated February 14, 2024, should be read in conjunction with our December 31, 2023 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). All of the information and statements contained in this MD&A are made as of February 14, 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 February 14, 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 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" or "GAAP") as issued by the International Accounting Standards Board. Production volumes are presented on a before royalties basis. Refer to the Abbreviations section for commonly used oil and gas terms.

OVERVIEW OF CENOVUS

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

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

Our operations involve activities across the full value chain to develop, produce, refine, transport and market crude oil, natural gas and refined petroleum products in Canada and internationally. Our physically 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.

For a description of our business segments see the Reportable Segments section of this MD&A.

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.

YEAR IN REVIEW

In 2023, we achieved a number of operational milestones, further enhanced our integrated operations and delivered significant returns to shareholders.

- **Delivered safe and reliable upstream performance.** Upstream production averaged 778.7 thousand BOE per day, compared with 786.2 thousand BOE per day in 2022. In the Conventional segment, we quickly and safely responded to significant wildfire activity that started in the second quarter. In the Oil Sands segment, our performance was impacted by lower production in the first half of the year as we prepared for the start-up of new wells pads. We were able to regain momentum in the last half of the year. Upstream production averaged 808.6 thousand BOE per day in the fourth quarter, our highest quarterly average since the fourth quarter of 2021.
- **Achieved Offshore milestones.** We materially progressed the West White Rose project to deliver first oil in 2026. Construction is approximately 75 percent complete, and we reached a major milestone on the project in the second quarter with the completion of the conical slip form operation for the concrete gravity structure. The Terra Nova floating production, storage and offloading unit ("FPSO") returned to the field in August and began producing in late November. We also achieved first gas production from the MAC field in Indonesia in September.
- **Further integrated our heavy oil production and refining capabilities.** In February, we acquired the remaining 50 percent interest in the Toledo Refinery from BP Products North America Inc. ("bp"), providing us full ownership and operatorship of the refinery (the "Toledo Acquisition"). We safely returned the refinery to full operations in June. At the Superior Refinery, we continued to progress towards a return to full operations. The Toledo Acquisition and the start-up of the Superior Refinery added approximately 129.0 thousand barrels per day of refining capacity, of which 79.0 thousand barrels per day is heavy oil refining capacity.

- **Safe and strong Canadian Refining performance.** In 2023, average crude oil unit throughput (or "throughput") increased 7.8 thousand barrels per day to 100.7 thousand barrels per day, and crude utilization was 91 percent (2022 – 84 percent). Average refined product production increased 9.0 thousand barrels per day to 114.2 thousand barrels per day. The increases in throughput and refined product production were due to limited downtime and reliable operations.
- **U.S. Refining operations**. Average throughput increased 58.9 thousand barrels per day to 459.7 thousand barrels per day in 2023. Crude utilization was 75 percent (2022 – 80 percent) and refined product production averaged 485.0 thousand barrels per day, an increase of 65.1 thousand barrels per day from 2022. The increases in throughput and refined product production were mainly driven by the Toledo and Superior refineries discussed above. The increases were partially offset by unplanned outages and planned maintenance across our operated and non-operated assets.
- **Reduced long-term debt.** We purchased US$1.0 billion of long-term debt in the third quarter at a discount of $84 million. In 2023 compared with 2022, long-term debt decreased $1.6 billion to $7.1 billion and Net Debt increased $778 million to $5.1 billion at December 31, 2023. In 2023, we strengthened our credit ratings with a rating upgrade from Finch Ratings Inc. to BBB Stable and improved outlooks from S&P Global Ratings and Moody's Investors Service from Stable to Positive.
- **Delivered significant cash returns to shareholders.** We returned $2.8 billion to shareholders, composed of the purchase of 43.6 million common shares for $1.1 billion through our NCIB, $1.0 billion through common share base dividends and preferred share dividends, and $711 million for the purchase and cancellation of 45.5 million Cenovus Warrants. On February 14, 2024, the Board declared a first quarter base dividend of $0.140 per common share and dividends for our preferred shares of $9 million.
- **Generated $8.8 billion in Adjusted Funds Flow**. Cash flow from operating activities was $7.4 billion (2022 – $11.4 billion) and Adjusted Funds Flow was $8.8 billion (2022 – $11.0 billion), primarily reflecting a weaker commodity price environment. Brent and WTI both decreased 18 percent, to US$82.62 per barrel and US$77.62 per barrel, respectively, and WCS at Hardisty decreased 22 percent to US$58.97 per barrel compared with 2022. Benchmark refined product pricing also fell compared with 2022, with diesel pricing decreasing 24 percent and gasoline pricing decreasing 19 percent. The Chicago 3-2-1 crack spread declined 29 percent to US$24.19 per barrel.
- **Pathways Alliance advances.** Engineering, subsurface evaluation and environmental field work for the proposed carbon capture and storage ("CCS") project was completed in preparation for filing regulatory applications in the first half of 2024. If completed, the CCS project will be one of the world's largest CCS networks and play an essential role in helping Canada progress its net zero ambitions.

January 1, 2024, marked the third anniversary of the closing of the transaction to combine Cenovus and Husky Energy Inc. ("Husky"). We have made significant progress advancing our strategy to maximize shareholder value through safe operations, the integration of our assets, cost and sustainability leadership, financial discipline, and Free Funds Flow growth. Over the three years we reduced long-term debt by $6.9 billion and reduced Net Debt by $8.0 billion. We have returned $6.7 billion to shareholders through our shareholder returns strategy, including the purchase and cancellation of 173.1 million common shares through our NCIB, the purchase and cancellation of 45.5 million Cenovus Warrants, and payment of dividends. We further integrated our assets through strategic acquisitions and completed the Superior Refinery rebuild. Lastly, we developed and are progressing work around our ambitious ESG targets.

Summary of Annual Results

($ millions, except where indicated)	2023	2022	2021
Upstream Production Volumes [1] (MBOE/d)	**778.7**	786.2	791.5
Downstream Crude Oil Unit Throughput [2] (Mbbls/d)	**560.4**	493.7	508.0
Downstream Production Volumes (Mbbls/d)	**599.2**	525.1	537.7
Revenues	**52,204**	66,897	46,357
Operating Margin [3]	**11,022**	14,263	9,373
Cash From (Used In) Operating Activities	**7,388**	11,403	5,919
Adjusted Funds Flow [3]	**8,803**	10,978	7,248
Per Share – Basic [3] ($)	**4.64**	5.63	3.59
Per Share – Diluted [3] ($)	**4.57**	5.47	3.54
Capital Investment	**4,298**	3,708	2,563
Free Funds Flow [3]	**4,505**	7,270	4,685
Net Earnings (Loss) [4]	**4,109**	6,450	587
Per Share – Basic ($)	**2.15**	3.29	0.27
Per Share – Diluted ($)	**2.12**	3.20	0.27
Total Assets	**53,915**	55,869	54,104
Total Long-Term Liabilities	**18,993**	20,259	23,191
Long-Term Debt, Including Current Portion	**7,108**	8,691	12,385
Net Debt	**5,060**	4,282	9,591
Cash Returns to Shareholders	**2,798**	3,457	475
Common Shares – Base Dividends	**990**	682	176
Base Dividends Per Common Share ($)	**0.525**	0.350	0.088
Common Shares – Variable Dividends	**—**	219	—
Variable Dividends Per Common Share ($)	**—**	0.114	—
Purchase of Common Shares Under NCIB	**1,061**	2,530	265
Payment for Purchase of Warrants	**711**	—	—
Preferred Share Dividends	**36**	26	34

(1) Refer to the Operating and Financial Results section of this MD&A for a summary of total upstream production by product type.
(2) Represents Cenovus's net interest in refining operations.
(3) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(4) Net earnings (loss) for all periods in the table above is the same as net earnings (loss) from continuing operations.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results and Oil and Gas Reserves — Upstream

	2023	Percent Change	2022
Upstream Production Volumes by Segment [1] (MBOE/d)			
Oil Sands	**595.4**	**1**	588.7
Conventional	**119.9**	**(6)**	127.2
Offshore	**63.4**	**(10)**	70.3
Total Production Volumes	**778.7**	**(1)**	786.2
Upstream Production Volumes by Product			
Bitumen (Mbbls/d)	**576.7**	**1**	570.3
Heavy Crude Oil (Mbbls/d)	**16.7**	**2**	16.3
Light Crude Oil (Mbbls/d)	**14.1**	**(26)**	19.1
NGLs (Mbbls/d)	**32.5**	**(10)**	36.2
Conventional Natural Gas (MMcf/d)	**832.6**	**(4)**	866.1
Total Production Volumes (MBOE/d)	**778.7**	**(1)**	786.2
Oil and Gas Reserves (MMBOE)			
Total Proved	**5,866**	**(4)**	6,082
Probable	**2,836**	**2**	2,787
Total Proved Plus Probable	**8,702**	**(2)**	8,869

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

Production

In 2023, total upstream production decreased slightly from 2022. The factors below increased production in 2023 compared with 2022:

- Higher production from our Oil Sands assets mainly due to the acquisition of the remaining 50 percent interest in the Sunrise Oil Sands Partnership ("SOSP", "Sunrise" or the "Sunrise Acquisition") from BP Canada Energy Group ULC ("bp Canada") on August 31, 2022, and successful results from the 2023 redevelopment program. Partially offsetting the increase was lower production at Christina Lake resulting from the timing of new wells pads in 2023.
- First gas production at the MBH and MDA fields in Indonesia in the fourth quarter of 2022, and from the MAC field in the third quarter of 2023.

The factors below decreased production in 2023 compared with 2022:

- The temporary shut-in of a significant portion of production in our Conventional operations in response to wildfire activity in the second quarter of 2023.
- Changes to the Liwan 3-1 gas sales agreement in China in the second quarter of 2022, concluding the amendment that temporarily increased sales volumes.
- A temporary unplanned outage in China in the second quarter of 2023, related to the disconnection of the umbilical by a third-party vessel in early April, reconnected in May.

Oil and Gas Reserves

Based on our reserves reports prepared by independent qualified reserves evaluators ("IQREs"), total proved reserves and total proved plus probable reserves at December 31, 2023 were approximately 5.9 billion BOE and 8.7 billion BOE, respectively. Total proved reserves decreased four percent from 2022, and proved plus probable reserves decreased two percent from 2022.

Additional information about our reserves is included in the Oil and Gas Reserves section of this MD&A.

Selected Operating Results — Downstream

	2023	Percent Change	2022
Downstream Crude Oil Unit Throughput (Mbbls/d)			
Canadian Refining	**100.7**	**8**	92.9
U.S. Refining	**459.7**	**15**	400.8
Total Crude Oil Unit Throughput	**560.4**	**14**	493.7
Downstream Production Volumes [(1)] (Mbbls/d)			
Canadian Refining	**114.2**	**9**	105.2
U.S. Refining	**485.0**	**16**	419.9
Total Downstream Production	**599.2**	**14**	525.1

(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 ran well in 2023 with crude utilization at the Upgrader and Lloydminster Refinery of 90 percent and 95 percent, respectively (2022 – 84 percent and 83 percent, respectively). The improved performance was driven by consistent operations in 2023, compared with planned turnarounds and temporary unplanned outages in 2022 at both assets. The increases were partially offset by unplanned outages at the Upgrader in the second and fourth quarters of 2023.

In our U.S. Refining operations, crude throughput increased by 58.9 thousand barrels per day as we:

- Closed the acquisition of the remaining 50 percent of the Toledo Refinery, increasing our throughput capacity by 80.0 thousand barrels per day.
- Safely restarted the Toledo Refinery. The Refinery was fully operational by the end of June and the utilization rate was 88 percent in the last half of the year. Utilization for the full year was 57 percent (2022 – 45 percent).
- Made significant progress towards a return to full operations at the Superior Refinery after being shut down since 2018. We introduced crude oil in mid-March and safely restarted the fluid catalytic cracking unit ("FCCU") in early October. During the last half of the year crude utilization was 66 percent.
- Had strong performance from the Wood River Refinery. In addition, planned turnaround activity in 2022 had a greater impact than the planned spring 2023 turnaround. Combined utilization at the Wood River and Borger refineries was 81 percent (2022 – 83 percent).

The increases were partially offset by:

- Planned turnarounds and temporary unplanned outages at the Borger Refinery that had a larger impact than the unplanned outages and turnaround completed in 2022.
- Unplanned outages combined with planned maintenance at the Lima Refinery in the second half of 2023. Crude utilization at the Lima Refinery in 2023 was 85 percent (2022 – 90 percent).
- In the fourth quarter of 2023, we flexed throughput at our U.S. refineries to optimize our margins as a result of significantly lower refining benchmark pricing.

Selected Consolidated Financial Results

Revenues

Revenues decreased 22 percent to $52.2 billion from 2022 primarily due to lower blended crude oil benchmark pricing impacting our Oil Sands segment, and lower natural gas and refined product benchmark pricing, partially offset by a weaker Canadian dollar on average relative to the U.S. dollar.

Operating Margin

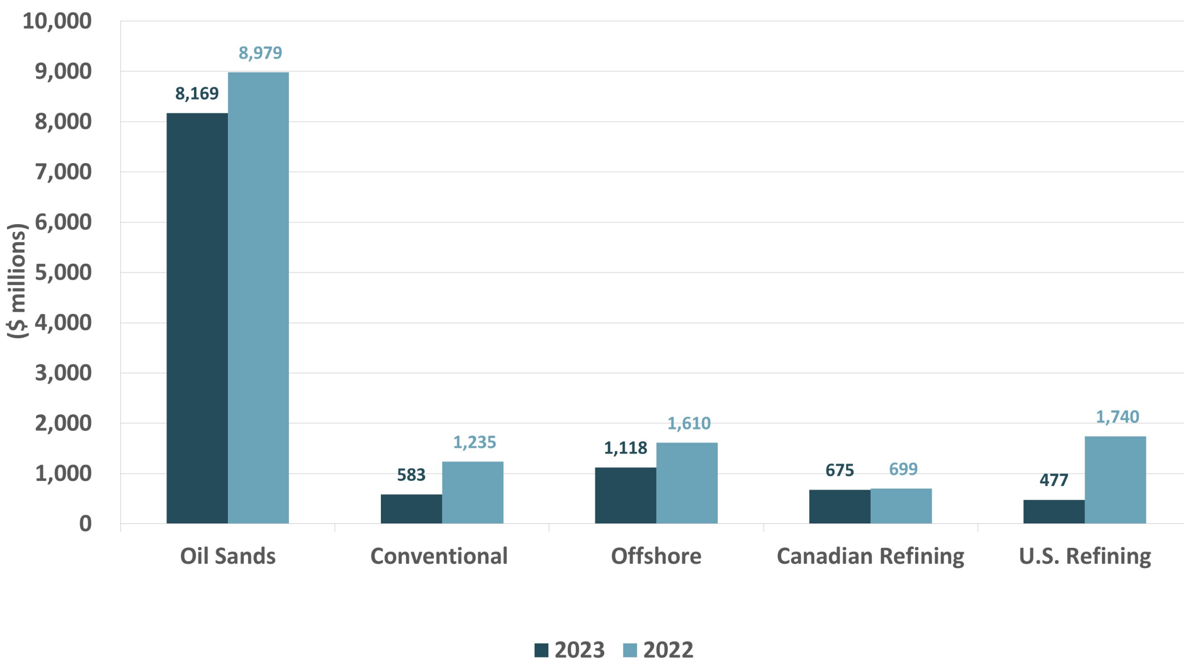
Operating Margin is a specified financial measure and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods.

($ millions)	2023	2022
Gross Sales [(1)]	**63,708**	79,152
Less: Royalties	**3,270**	4,868
Revenues [(1)]	**60,438**	74,284
Expenses		
Purchased Product [(1)]	**31,425**	39,150
Transportation and Blending [(1)]	**11,088**	12,301
Operating Expenses	**6,891**	6,839
Realized (Gain) Loss on Risk Management Activities	**12**	1,731
Operating Margin	**11,022**	14,263

(1) Comparative periods reflect certain revisions. See Note 39 of the Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Operating Margin by Segment

Years Ended December 31, 2023 and 2022



Operating Margin decreased $3.2 billion to $11.0 billion in 2023 compared with 2022, primarily due to:

- Lower realized crude oil and NGLs sales prices resulting from lower benchmark pricing.
- Decreased gross margin from the U.S. Refining segment resulting from lower market crack spreads.
- Lower sales volumes from our Offshore segment.
- Higher non-fuel operating expenses from the Oil Sands segment. Oil Sands per-unit non-fuel operating expenses increased 15 percent from 2022 to $8.94 per barrel in 2023, primarily due to higher repairs and maintenance costs as a result of planned turnarounds at Foster Creek and Christina Lake, and lower gross sales volumes.
- A rise in operating expenses in the U.S. Refining segment, primarily due to the Toledo acquisition and the start-up of both the Superior and Toledo refineries.

These decreases in Operating Margin were partially offset by:

- Significantly lower realized risk management losses in 2023, compared with 2022.
- Lower royalties in the Oil Sands and Conventional segments, resulting from lower crude oil and natural gas benchmark pricing.
- Higher throughput and refined product production primarily from the Toledo and Superior refineries as discussed above.

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

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

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

($ millions)	**2023**	2022
Cash From (Used in) Operating Activities	**7,388**	11,403
(Add) Deduct:		
Settlement of Decommissioning Liabilities	**(222)**	(150)
Net Change in Non-Cash Working Capital	**(1,193)**	575
Adjusted Funds Flow	**8,803**	10,978

Cash from operating activities decreased in 2023 compared with 2022. The decline was primarily due to a lower Operating Margin as discussed above and changes in non-cash working capital, partially offset by $631 million paid in 2022 for the contingent payment associated with the acquisition of 50 percent of the FCCL Partnership. The net change in non-cash working capital in 2023 was $1.2 billion, mainly due to the settlement of a $1.2 billion income tax liability in the first quarter of 2023.

Adjusted Funds Flow was lower in 2023 compared with 2022, primarily due to decreased Operating Margin.

Net Earnings (Loss)

Net earnings in 2023 was $4.1 billion compared with $6.5 billion in 2022. The decrease was primarily due to lower Operating Margin as discussed above, in addition to:

- The revaluation gain related to the Sunrise Acquisition in 2022.
- Lower other income in 2023 primarily due to the 2022 insurance proceeds related to the 2018 incidents at the Superior Refinery and in the Atlantic region.
- Higher net gains on asset divestitures in 2022.

The decreases were partially offset by:

- Lower income tax expense.
- Unrealized foreign exchange gains in 2023 compared with losses in 2022.
- Decreased general and administrative expenses due to lower long-term incentive costs.
- Lower finance costs due to the purchase of unsecured notes in 2022 and the third quarter of 2023.
- Decreased losses on the re-measurement of contingent payments.

Net Debt

As at ($ millions)	**December 31, 2023**	December 31, 2022
Short-Term Borrowings	**179**	115
Current Portion of Long-Term Debt	**—**	—
Long-Term Portion of Long-Term Debt	**7,108**	8,691
Total Debt	**7,287**	8,806
Less: Cash and Cash Equivalents	**(2,227)**	(4,524)
Net Debt	**5,060**	4,282

Long-term debt decreased by $1.6 billion from December 31, 2022, primarily due to the purchase of unsecured notes with an aggregate principal amount of US$1.0 billion in the third quarter of 2023. Net Debt increased by $778 million from December 31, 2022, mainly due to cash from operating activities of $7.4 billion, capital investment of $4.3 billion, acquisitions of $515 million and cash returns to shareholders of $2.8 billion.

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

Capital Investment [1]

($ millions)	2023	2022
Upstream		
Oil Sands	**2,382**	1,792
Conventional	**452**	344
Offshore	**642**	310
Total Upstream	**3,476**	2,446
Downstream		
Canadian Refining	**145**	117
U.S. Refining	**602**	1,059
Total Downstream	**747**	1,176
Corporate and Eliminations	**75**	86
Total Capital Investment	**4,298**	3,708

(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 2023 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 in the first and fourth quarters, in addition to the tie-back of Narrows Lake to Christina Lake and other growth projects at Foster Creek and Sunrise.
- Drilling, completion, tie-in and infrastructure projects in the Conventional segment.
- The progression of the West White Rose project and Terra Nova asset life extension ("ALE") project in the Atlantic region.
- The Superior Refinery rebuild and margin improvement and reliability initiatives at the Wood River, Borger, Lima and Toledo refineries.

Drilling Activity

	Net Stratigraphic Test Wells and Observation Wells		Net Production Wells [1]	
	2023	2022	**2023**	2022
Foster Creek	**87**	52	**44**	29
Christina Lake	**53**	—	**27**	31
Sunrise	**38**	15	**24**	10
Lloydminster Thermal	**71**	98	**9**	33
Lloydminster Conventional Heavy Oil	**3**	8	**34**	11
Other [2]	**3**	22	**—**	—
	255	195	**138**	114

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

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

	2023			2022		
(net wells)	**Drilled**	**Completed**	**Tied-in**	Drilled	Completed	Tied-in
Conventional	**38**	**37**	**41**	31	35	36

In the Offshore segment, we drilled and completed one (0.4 net) planned development well at the MAC field in Indonesia in 2023 (2022 – drilled and completed nine (3.6 net) planned development wells at the MBH, MDA and MAC fields 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$/bbl, unless otherwise indicated)	2023	Percent Change	2022	Q4 2023	Q3 2023	Q4 2022
Dated Brent	**82.62**	**(18)**	101.19	**84.05**	86.76	88.71
WTI	**77.62**	**(18)**	94.23	**78.32**	82.26	82.65
Differential Dated Brent-WTI	**5.00**	**(28)**	6.96	**5.73**	4.50	6.06
WCS at Hardisty	**58.97**	**(22)**	76.01	**56.43**	69.35	56.99
Differential WTI-WCS at Hardisty	**18.65**	**2**	18.22	**21.89**	12.91	25.66
WCS at Hardisty (C$/bbl)	**79.59**	**(19)**	98.51	**76.95**	93.06	77.42
WCS at Nederland	**69.74**	**(19)**	85.77	**71.59**	77.89	67.65
Differential WTI-WCS at Nederland	**7.88**	**(7)**	8.46	**6.73**	4.37	15.00
Condensate (C5 at Edmonton)	**76.61**	**(18)**	93.78	**76.24**	77.96	83.40
Differential Condensate-WTI Premium/(Discount)	**(1.01)**	**(124)**	(0.45)	**(2.08)**	(4.30)	0.75
Differential Condensate-WCS [2] Premium/(Discount)	**17.64**	**1**	17.77	**19.81**	8.61	26.41
Condensate (C$/bbl)	**103.43**	**(15)**	121.78	**103.90**	104.63	113.25
Synthetic at Edmonton	**79.61**	**(19)**	98.66	**78.64**	84.95	86.79
Differential Synthetic-WTI Premium/(Discount)	**1.99**	**55**	4.43	**0.32**	2.69	4.14
Synthetic at Edmonton (C$/bbl)	**107.47**	**(16)**	128.19	**107.21**	114.01	117.87
Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**97.86**	**(19)**	120.63	**83.72**	105.59	102.80
Chicago Ultra-low Sulphur Diesel ("ULSD")	**109.70**	**(24)**	143.85	**107.24**	113.77	140.95
Refining Benchmarks						
Chicago 3-2-1 Crack Spread [3]	**24.19**	**(29)**	34.15	**13.24**	26.06	32.87
Group 3 3-2-1 Crack Spread [3]	**29.66**	**(11)**	33.21	**18.55**	36.96	29.99
Renewable Identification Numbers ("RINs")	**7.04**	**(9)**	7.72	**4.77**	7.42	8.54
Natural Gas Prices						
AECO [4] (C$/Mcf)	**2.64**	**(50)**	5.31	**2.30**	2.60	5.11
NYMEX [5] (US$/Mcf)	**2.74**	**(59)**	6.64	**2.88**	2.55	6.26
Foreign Exchange Rates						
US$ per C$1 - Average	**0.741**	**(4)**	0.769	**0.734**	0.746	0.737
US$ per C$1 - End of Period	**0.756**	**2**	0.738	**0.756**	0.740	0.738
RMB per C$1 - Average	**5.247**	**1**	5.170	**5.304**	5.402	5.241

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

Crude Oil and Condensate Benchmarks

Crude oil benchmark prices, Brent and WTI, have trended lower in 2023 compared with 2022. In 2023, we saw a more balanced crude market, resulting in average prices falling from elevated levels in 2022. Global demand growth remained healthy in 2023 despite macroeconomic concerns, but was outpaced by high supply growth from non-OPEC+ countries. Repeated and extended cuts to OPEC+ production quotas have offset production growth elsewhere and supported prices. In the first half of 2022, prices were high as a result of rising global demand amid low global inventories and limited crude production spare capacity, which was exacerbated by risks related to Russian export supply shortfall uncertainty. Prices then decreased gradually in the second half of 2022 as material Russian supply disruption concerns eased and nearly all short-term supply sources were accessed to meet demand, including unprecedented releases of U.S. government strategic petroleum reserves ("SPRs").

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

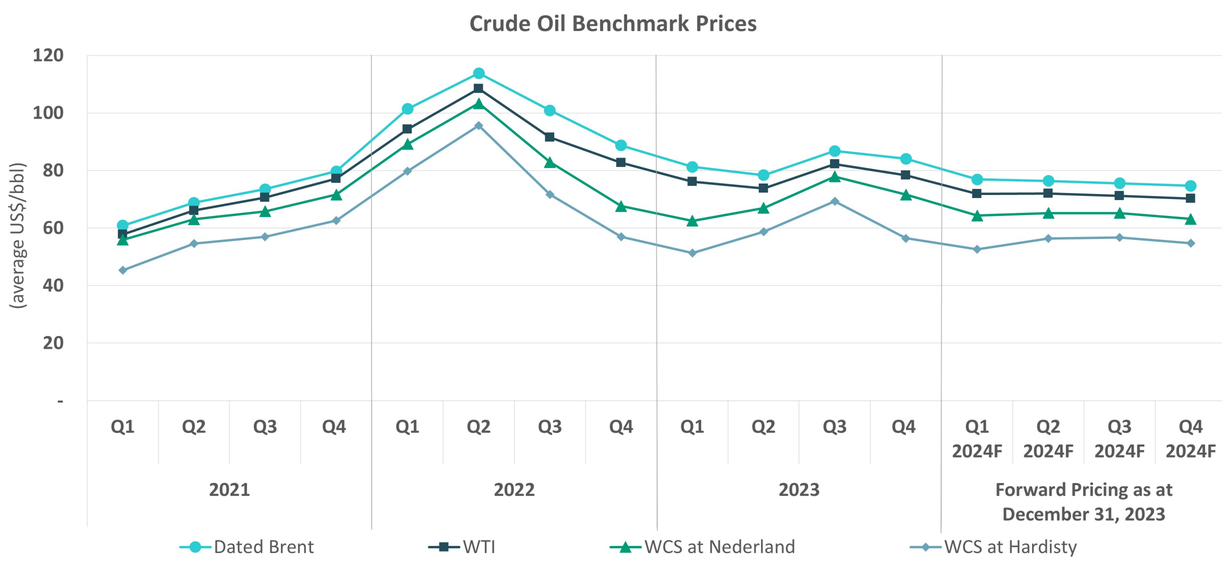
The price received for our Atlantic crude oil and Asia Pacific NGLs is primarily driven by the price of Brent. The Brent-WTI differential narrowed in 2023 compared with 2022. In 2022, the differential widened significantly in the months following the Russian invasion of Ukraine in February 2022.

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. On a full-year basis, the average WTI-WCS differential at Hardisty in 2023 was consistent with 2022. Transportation costs reflected pipeline economics in 2022 and 2023 as supply largely remained within export capacity. WCS differentials widened in the fourth quarter of 2023, most notably in December. The widening in the fourth quarter was due to high production and outages at Alberta refineries leading to exports above pipeline capacity. The WCS quality differential was consistent year-over-year, as differentials widened in the second half of 2022 and the first half of 2023 as a result of unplanned refinery maintenance, high global refining utilization, rising supply of medium and heavy oil barrels into the market from OPEC+, releases of SPRs and volatile refined product pricing.

WCS at Nederland is a heavy oil benchmark for sales of our product at the USGC. The WTI-WCS at Nederland differential is representative of the heavy oil quality discount and is influenced by global heavy oil refining capacity and global heavy oil supply. The WTI-WCS at Nederland differential in 2023 declined from 2022, due to the same factors impacting the WTI-WCS differential at Hardisty discussed above.

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

In 2023, synthetic crude at Edmonton was at a lower premium to WTI compared with 2022. Synthetic crude prices were elevated in 2022 as a result of upgrader maintenance in Western Canada and strong refinery demand for light crude oil. High upgrader production in 2023 resulted in this premium eroding. The synthetic crude premium to WTI declined in the fourth quarter relative to the third quarter of 2023 as a result of exports 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. On a full-year basis, the average Condensate-WCS differential in 2023 was consistent with 2022. Edmonton condensate differentials are highly seasonal, typically trading at a premium to WTI during peak winter demand and a discount to WTI during the summer months. This is counter-seasonal to the WTI-WCS differential, often resulting in the WCS-Condensate differential experiencing wide swings between summer and winter.

In 2023 and 2022, the average Edmonton condensate benchmark was near parity with WTI as demand for heavy crude blending in Alberta has been strong and condensate supply remains tight.

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.

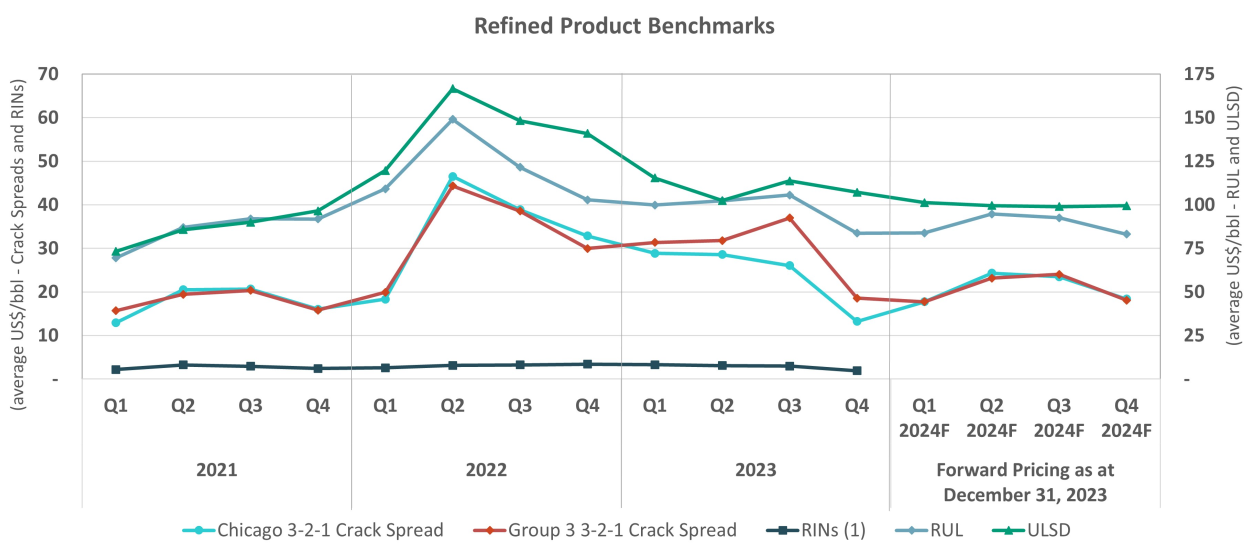
Refined product prices declined in 2023 compared with 2022. Market crack spreads also declined during this period as 2022 saw periods of historically high refined product prices and refining margins due to pandemic refinery rationalization, Russian export volatility and critically low global inventories of refined products.

Reduced refinery outages and incremental global capacity additions resulted in declining refined product prices relative to WTI in 2023, compared with 2022, but crack spreads remained above historical norms. Diesel margins declined year-over-year but were high on average amid strong demand, tight global supply and demand balances, and continued low inventories. Gasoline margins were strong on average in 2023 but weakened in the fourth quarter as seasonally lower demand and high refinery utilization resulted in excess supply and high inventory builds. Gasoline and diesel margins, and crack spreads, decreased significantly in December. The Chicago refined product market saw periods of weakness in 2023 relative to Group 3 and the USGC as regional refining utilization was high and waterway maintenance prevented products from being barged to other market demand centers.

On a full-year basis, average RINs costs were consistent in 2023 compared with 2022, but declined in the fourth 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 many 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.



(1) There are no forward prices for RINs.

Natural Gas Benchmarks

Average NYMEX and AECO natural gas prices decreased significantly in 2023 compared with 2022. Prices were very high in 2022 due to strong U.S. domestic demand and high liquified natural gas exports, coupled with a lagged supply response and strong global pricing amid Russia supply concerns. Prices weakened in 2023 as U.S. supply grew rapidly, reaching record high levels, exceeding demand growth which 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 2023, the Canadian dollar on average weakened relative to the U.S. dollar compared with 2022, positively impacting our reported revenues. The Canadian dollar strengthened slightly relative to the U.S. dollar as at December 31, 2023, compared with December 31, 2022, resulting in unrealized foreign exchange gains 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 2023, the Canadian dollar on average strengthened slightly relative to RMB compared with 2022, 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 interest expense and affect how certain liabilities are measured and impact our cash flow and financial results.

As at December 31, 2023, the Bank of Canada's Policy Interest Rate was 5.00 percent, an increase from 4.25 percent on December 31, 2022, due to concerns over inflation. On January 24, 2024, the Bank of Canada announced the rate will remain at 5.00 percent.

OUTLOOK

Commodity Price Outlook

Global crude oil prices traded in a narrower range in 2023 compared with 2022, but remained volatile following the EU import ban on Russia's crude oil and products and subsequent reshuffling of global trade flows, global macro-economic concerns related to rising interest rates and inflation, and geopolitical events such as the crisis in Israel and Gaza. In 2022, global crude oil prices spiked in the first half of the year following Russia's invasion of Ukraine as low global spare production capacity stoked fears of supply scarcity. Prices gradually declined in the second half of 2022 as nearly all short-term supply sources were called on, and Russian exports remained resilient. Crude oil demand growth was ultimately strong in 2023 despite weak macroeconomic indicators, supported by the lifting of China's COVID-19 restrictions earlier in the year. High supply growth from non-OPEC+ put downward pressure on prices through the year; however, the OPEC+ announced and extended production cuts have managed and supported the downward pressure from supply growth. OPEC+ policy remains crucial to global oil balances and 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. The OPEC+ announced extension of production cuts that will continue to be supportive of pricing, with production quotas being a key driver of crude oil prices. Overall, we expect the general outlook for crude oil and refined product prices will be volatile and impacted by OPEC+ policy, the duration and severity of the ongoing Russian invasion of Ukraine, the extent to which Russian exports are reduced by sanctions or production cuts, the pace of non-OPEC+ supply growth, the refilling of SPRs, and the crisis in Israel and Gaza. In addition, weakening global economic activity, inflation and 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. We expect the start-up of the Trans Mountain pipeline expansion in 2024 to have a narrowing impact on WTI-WCS differentials.
- We expect refined product prices and market crack spreads will remain volatile. Economic effects of the ongoing Russian invasion of Ukraine and central bank policies could impact demand. Refined product prices and market crack spreads are likely to continue to fluctuate, adjusting for seasonal trends and refinery utilization in North America.
- NYMEX and AECO natural gas prices are expected to remain under pressure in the near-term due to strong supply and ample natural gas in storage. Weather will continue to be a key driver of demand and impact prices.
- We expect the Canadian dollar to continue to be impacted by 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. The restart of the Superior and Toledo refineries provide further physical integration. Both refineries process blended crude oil from our Oil Sands assets and HSB from the Upgrader.

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.
- Traditional crude oil storage tanks in various geographic locations.

Key Priorities for 2024

Our 2024 priorities are focused on safety, maximizing shareholder value through downstream profitability, advancing major projects and other asset opportunities and cost leadership, and continuing to advocate for our company and industry.

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 billion, which serves as our floor on Net Debt, and we strive to continue to make progress towards this target. When Net Debt is at the $4 billion floor at quarter-end, we will target to return 100 percent of the following quarter's Excess Free Funds Flow to shareholder returns.

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 asset life extension project ("SeaRose 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 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 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. 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 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.

2024 Corporate Guidance

Our 2024 capital investment budget is between \$4.5 billion and \$5.0 billion. This includes \$3.0 billion directed towards sustaining production and supporting continued safe and reliable operations, and between \$1.5 billion and \$2.0 billion in optimization and growth capital.

Optimization and growth capital is mainly related to:

- Progressing the West White Rose project.
- Incrementally growing production at the Foster Creek, Christina Lake and Sunrise facilities.
- Initiatives in our downstream business to improve reliability and increase margin capture.
- Opportunities in the Conventional segment.

The following table shows guidance for 2024:

	Capital Investment ($ millions)	Production (MBOE/d)	Crude Oil Unit Throughput (Mbbls/d)
Upstream			
Oil Sands	**2,500 - 2,750**	**590 - 610**	
Conventional	**350 - 425**	**120 - 130**	
Offshore	**850 - 950**	**60 - 70**	
Downstream	**750 - 850**		**630 - 670**
Corporate and Eliminations	**60 - 70**		

Our 2024 guidance dated December 13, 2023, is available on our website at cenovus.com.

REPORTABLE SEGMENTS

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. The Company renamed its Canadian Manufacturing segment to Canadian Refining in 2023.
- **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 (jointly owned with operator Phillips 66). Cenovus markets some of its own and third-party refined products including gasoline, diesel, jet fuel and asphalt. The Company renamed its U.S. Manufacturing segment to U.S. Refining in 2023.

Corporate and Eliminations

Corporate and eliminations, primarily includes Cenovus-wide costs for general and administrative, financing activities, gains and losses on risk management for corporate related derivative instruments and foreign exchange. Eliminations include adjustments for 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.

UPSTREAM

Oil Sands

In 2023, we:

- Delivered safe operations.
- Produced 593.4 thousand barrels of crude oil per day (2022 – 586.6 thousand barrels of crude oil per day).
- Started production on three new well pads at both Foster Creek and Christina Lake.
- Completed a planned turnaround at Foster Creek in the second quarter.
- Completed a planned turnaround at Christina Lake in the third quarter with minimal production impacts.
- Generated Operating Margin of $8.2 billion, a decrease of $810 million compared with 2022 primarily due to lower average realized sales prices.
- Invested capital of $2.4 billion primarily for sustaining activities including the drilling of stratigraphic test wells as part of our integrated winter program in the first and fourth quarters, in addition to the tie-back of Narrows Lake to Christina Lake and other growth projects at Foster Creek and Sunrise.
- Averaged a Netback of $38.10 per BOE (2022 – $49.10 per BOE).

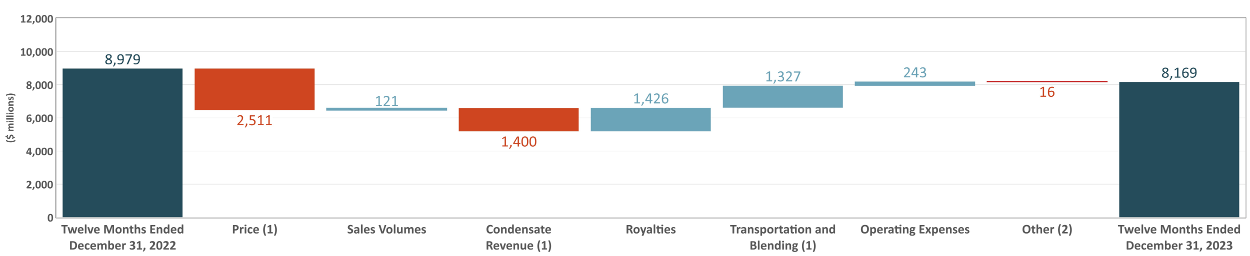
Financial Results

($ millions)	**2023**	2022
Revenues		
Gross Sales [1]	**26,192**	34,683
Less: Royalties	**3,059**	4,493
	23,133	30,190
Expenses		
Purchased Product [1]	**1,457**	4,718
Transportation and Blending	**10,774**	12,036
Operating	**2,716**	2,930
Realized (Gain) Loss on Risk Management	**17**	1,527
Operating Margin	**8,169**	8,979
Unrealized (Gain) Loss on Risk Management	**15**	(68)
Depreciation, Depletion and Amortization	**2,993**	2,763
Exploration Expense	**19**	9
(Income) Loss from Equity-Accounted Affiliates	**6**	8
Segment Income (Loss)	**5,136**	6,267

(1) Comparative periods reflect certain revisions. See Note 39 of the Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Operating Margin Variance

Year Ended December 31, 2023



(1) Reported revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expenses. The crude oil price excludes the impact of condensate purchases. Changes to price include the impact of realized risk management gains and losses.

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

Operating Results

	2023	2022
Total Sales Volumes [(1)] (MBOE/d)	**589.5**	585.8
Total Realized Price [(2)] ($/BOE)	**73.02**	91.70
Crude Oil Production by Asset (Mbbls/d)		
Foster Creek	**186.3**	191.0
Christina Lake	**237.4**	246.5
Sunrise [(3)]	**48.9**	31.3
Lloydminster Thermal	**104.1**	99.9
Lloydminster Conventional Heavy Oil	**16.7**	16.3
Total Crude Oil Production [(4)] [(5)] (Mbbls/d)	**593.4**	586.6
Natural Gas [(6)] (MMcf/d)	**11.9**	12.3
Total Production (MBOE/d)	**595.4**	588.7
Effective Royalty Rate [(7)] (percent)		
Foster Creek	**25.1**	30.5
Christina Lake	**29.5**	30.8
Sunrise	**6.8**	7.3
Lloydminster [(8)]	**9.5**	10.5
Total Effective Royalty Rate	**21.9**	25.2
Transportation and Blending Expense [(2)] ($/BOE)	**8.18**	7.89
Operating Expense [(2)] ($/BOE)	**12.54**	13.75
Per Unit DD&A [(2)] ($/BOE)	**12.94**	11.90

(1) Bitumen, heavy crude oil and natural gas.
(2) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(3) On August 31, 2022, we acquired the remaining 50 percent interest in Sunrise from bp Canada.
(4) Bitumen production in 2022 included 1.6 thousand barrels per day from the Tucker asset that was sold on January 31, 2022.
(5) Oil Sands production is primarily bitumen, except for Lloydminster conventional heavy oil, which is heavy crude oil.
(6) Conventional natural gas product type.
(7) Effective royalty rates are equal to royalty expense divided by product revenue, net of transportation expenses.
(8) Composed of Lloydminster thermal and Lloydminster conventional heavy oil assets.

Revenues

Price

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

Our realized sales price decreased to $73.02 per BOE in 2023 from $91.70 per BOE in 2022 mainly due to lower WTI benchmark prices. In 2023, WTI averaged US$77.62 per barrel (2022 – US$94.23 per barrel) and the WTI-WCS at Hardisty differential was US$18.65 per barrel (2022 – US$18.22 per barrel). In 2023, condensate benchmark pricing was at a US$17.64 per barrel premium to WCS at Hardisty, compared with US$17.77 per barrel premium in 2022.

Gross sales included $1.2 billion (2022 – $4.4 billion) from third-party sourced volumes and $377 million (2022 – $358 million) relating to construction, transportation and blending activities.

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

Production Volumes

Oil Sands crude oil production was 593.4 thousand barrels per day in 2023 (2022 – 586.6 thousand barrels per day).

In 2023, we sold approximately 25 percent (2022 – 20 percent) of our oil sands crude oil sales volumes to third parties at U.S. destinations and sold approximately 20 percent of our oil sands crude oil sales volumes to our Canadian and U.S. downstream operations. All remaining sales were at Canadian destinations.

Production at Foster Creek decreased 4.7 thousand barrels per day to 186.3 thousand barrels per day in 2023 compared with 2022, primarily due to a planned turnaround that commenced in mid-April and completed in early May 2023, which had a greater impact than planned maintenance and an unplanned outage in 2022. The decrease was partially offset by three new well pads that started up in 2023.

Production at Christina Lake decreased 9.1 thousand barrels per day to 237.4 thousand barrels per day in 2023 compared with 2022, primarily due to the timing of three new well pads that started up in 2023 combined with strong production in 2022 from development wells drilled in prior years. The decrease was partially offset by turnaround activity in 2022. We completed a planned turnaround in the third quarter of 2023 that had minimal production impacts.

Production at Sunrise increased 17.6 thousand barrels per day to 48.9 thousand barrels per day in 2023, compared with 2022. The Sunrise Acquisition was completed on August 31, 2022. In addition, successful results from our 2023 redevelopment program completed in the third quarter increased production year-over-year.

Production from our Lloydminster thermal assets increased 4.2 thousand barrels per day to 104.1 thousand barrels per day in 2023, compared with 2022. The increase was due to first oil at the Spruce Lake North thermal plant in August 2022, partially offset by wells taken offline for a redevelopment program and workover activity in 2023.

Royalties

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

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

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

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

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

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

In 2023, royalties were $3.1 billion (2022 – $4.5 billion). The Oil Sands effective royalty rate decreased to 21.9 percent in 2023 from 25.2 percent in 2022 primarily due to lower realized pricing and lower Alberta oil sands sliding scale royalty rates.

Expenses

Transportation and Blending

In 2023, blending costs decreased $1.4 billion to $8.9 billion compared with 2022 due to lower condensate prices, partially offset by higher volumes. Transportation costs rose $138 million to $1.8 billion in 2023 compared with 2022, mainly due to the Sunrise Acquisition.

Per-unit Transportation Expenses

Transportation costs increased to $8.18 per BOE in 2023 from $7.89 per BOE in 2022.

At Foster Creek, per-unit transportation costs increased slightly to $11.98 per barrel in 2023 from $11.78 per barrel in 2022, primarily due to higher storage costs, partially offset by lower fixed rail costs. In 2023, we shipped 44 percent (2022 – 43 percent) of our volumes from Foster Creek to U.S. destinations.

At Christina Lake, transportation costs increased slightly to $6.69 per barrel in 2023 from $6.51 per barrel in 2022. Increased tariff rates and a higher percentage of our volumes shipped to U.S. destinations were partially offset by lower fixed rail costs. In 2023, we shipped 18 percent (2022 – 13 percent) of our volumes from Christina Lake to U.S. destinations.

At Sunrise, transportation costs increased slightly to $12.47 per barrel in 2023 from $12.26 per barrel in 2022, mainly due to higher tariff rates. In 2023, we shipped 50 percent (2022 – 51 percent) of our volumes from Sunrise to U.S. destinations.

At our other Oil Sands assets, transportation costs in 2023, were $3.51 per barrel (2022 – $3.49 per barrel).

Operating

Primary drivers of our operating expenses in 2023 were fuel, workforce, repairs and maintenance, and chemicals. Total operating expenses decreased $214 million to $2.7 billion in 2023 compared with 2022, mainly driven by lower fuel costs as a result of significant declines in AECO benchmark prices. The decreases were offset by higher repairs and maintenance costs in 2023, compared with 2022. 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.

Unit Operating Expenses (1)

($/BOE)	2023	Percent Change	2022
Foster Creek			
Fuel	**3.48**	**(43)**	6.07
Non-Fuel	**7.96**	**22**	6.52
Total	**11.44**	**(9)**	12.59
Christina Lake			
Fuel	**2.98**	**(41)**	5.07
Non-Fuel	**5.54**	**14**	4.87
Total	**8.52**	**(14)**	9.94
Sunrise			
Fuel	**4.78**	**(32)**	7.01
Non-Fuel	**12.24**	**17**	10.48
Total	**17.02**	**(3)**	17.49
Other Oil Sands (2)			
Fuel	**4.54**	**(38)**	7.35
Non-Fuel	**15.78**	**5**	15.10
Total	**20.32**	**(9)**	22.45
Total Oil Sands			
Fuel	**3.60**	**(39)**	5.95
Non-Fuel	**8.94**	**15**	7.80
Total	**12.54**	**(9)**	13.75

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

Per-unit non-fuel costs increased in 2023 compared with 2022 at all of our Oil Sands assets, primarily due to:

- Lower sales volumes and planned turnarounds at Foster Creek and Christina Lake, partially offset by a planned turnaround, maintenance activity and an unplanned outage in 2022.
- Higher repairs and maintenance costs at Sunrise, partially offset by higher gross sales volumes in 2023.
- A rise in repairs and maintenance and workover activity in our other Oil Sands assets.

Netbacks [1]

($/BOE)	Year Ended December 31, 2023	2022
Sales Price	**73.02**	91.70
Royalties	**14.20**	20.96
Transportation and Blending	**8.18**	7.89
Operating Expenses	**12.54**	13.75
Netback	**38.10**	49.10

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

Realized (Gain) Loss on Risk Management

In 2023, our realized risk management losses were $17 million (2022 – $1.5 billion). The decrease from 2022 is due to management's decision to liquidate our WTI positions related to crude oil sales price risk management in the second quarter of 2022.

Conventional

In 2023, we:

- Delivered safe operations.
- Produced 119.9 thousand BOE per day (2022 – 127.2 thousand BOE per day).
- Responded to wildfires in northern Alberta. In early May, we temporarily shut-in approximately 85 thousand BOE per day of production in the operating areas of Rainbow Lake, Elmworth-Wapiti, Kaybob-Edson and Clearwater to ensure the safety of our staff, local communities and assets. The majority of our wells and facilities impacted by the fire were restarted by June. Additional wildfire activity impacted our Rainbow Lake property in September and into the fourth quarter, and had minor impacts on production. We returned to full operations in the fourth quarter.
- Generated Operating Margin of $583 million, a decrease from $1.2 billion in 2022 primarily due to lower average realized sales prices.
- Invested capital of $452 million with continued focus on drilling, completion, tie-in and infrastructure projects.
- Averaged a Netback of $12.02 per BOE (2022 – $27.43 per BOE).

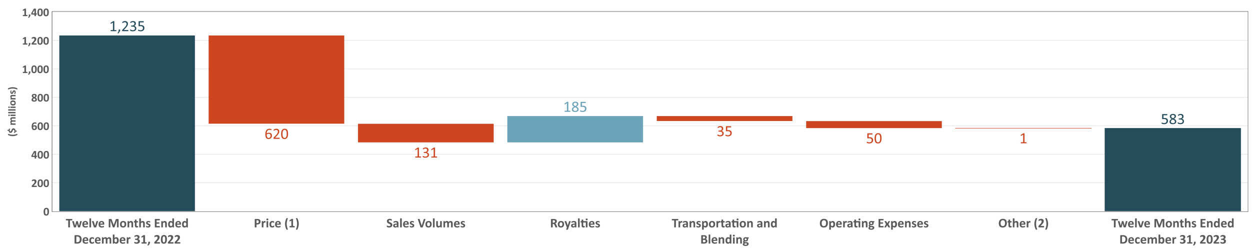
Financial Results

($ millions)	2023	2022
Revenues		
Gross Sales [1]	**3,273**	4,439
Less: Royalties	**112**	298
	3,161	4,141
Expenses		
Purchased Product	**1,695**	2,023
Transportation and Blending [1]	**298**	250
Operating	**590**	541
Realized (Gain) Loss on Risk Management	**(5)**	92
Operating Margin	**583**	1,235
Unrealized (Gain) Loss on Risk Management	**(19)**	13
Depreciation, Depletion and Amortization	**386**	370
Exploration Expense	**6**	1
Segment Income (Loss)	**210**	851

(1) Comparative periods reflect certain revisions. See Note 39 of the Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Operating Margin Variance

Year Ended December 31, 2023



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

Operating Results

	2023	2022
Total Sales Volumes (MBOE/d)	**119.9**	127.2
Total Realized Price [1] ($/BOE)	**31.76**	48.15
Light Crude Oil ($/bbl)	**101.34**	118.64
NGLs ($/bbl)	**48.25**	63.22
Conventional Natural Gas ($/Mcf)	**3.91**	6.50
Production by Product		
Light Crude Oil (Mbbls/d)	**5.9**	7.5
NGLs (Mbbls/d)	**21.7**	23.8
Conventional Natural Gas (MMcf/d)	**554.1**	576.1
Total Production (MBOE/d)	**119.9**	127.2
Conventional Natural Gas Production (percentage of total)	**77**	75
Crude Oil and NGLs Production (percentage of total)	**23**	25
Effective Royalty Rate (percent)	**10.8**	15.4
Transportation Expense [1] ($/BOE)	**4.16**	3.16
Operating Expense [1] ($/BOE)	**13.02**	11.18
Per Unit DD&A [1] ($/BOE)	**8.76**	8.23

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

Revenues

Price

Our total realized sales price decreased in 2023, compared with 2022, primarily due to lower crude oil and natural gas benchmark prices.

In 2023, gross sales included $1.7 billion (2022 – $2.0 billion) relating to third-party sourced volumes; and amounts relating to processing activities undertaken for third parties of $188 million (2022 – $178 million).

Production Volumes

Production volumes decreased 7.3 thousand BOE per day in 2023 to 119.9 thousand BOE per day in 2023 compared with 2022. The year-over-year decrease was primarily due to the impact of the wildfires in the second quarter of 2023, partially offset by successful results from our 2023 development program.

Royalties

The Conventional assets are subject to royalty regimes in Alberta and British Columbia. Royalties decreased to $112 million in 2023 from $298 million in 2022 and effective royalty rates declined, primarily due to sharp declines in natural gas 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 increased $48 million to $298 million in 2023 compared with 2022, and per-unit transportation costs increased to $4.16 per BOE in 2023 from $3.16 per BOE in 2022. The increases were mainly due to higher tariff rates and additional storage costs, combined with lower sales volumes.

Operating

Primary drivers of operating expenses in 2023 were repairs and maintenance, workforce, property taxes and lease costs, and electricity. Total operating expenses increased $49 million to $590 million in 2023 compared with 2022, due to the higher repairs and maintenance costs. The wildfires had minimal impact on total operating expenses. Operating expenses per BOE increased $1.84 per BOE to $13.02 per BOE in 2023 compared with 2022, due to the same factors impacting total operating costs and lower sales volumes as a result of wildfire activity.

Netbacks [(1)]

($/BOE)	**2023**	2022
Sales Price	**31.76**	48.15
Royalties	**2.56**	6.38
Transportation and Blending	**4.16**	3.16
Operating Expenses	**13.02**	11.18
Netback	**12.02**	27.43

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

Offshore

In 2023, we:

- Delivered safe operations.
- Resumed production at the Terra Nova FPSO in late November. Our share of production in December was 4.1 thousand barrels per day.
- Achieved first gas production from the MAC field in Indonesia in September.
- Produced 63.4 thousand BOE per day of light crude oil, NGLs and natural gas (2022 – 70.3 thousand BOE per day).
- Generated Operating Margin of $1.1 billion, a decrease of $492 million compared with 2022, mainly due to lower sales volumes from our Atlantic and China operations, and decreased realized light crude oil sales prices.
- Earned a Netback of $56.48 per BOE (2022 – $68.90 per BOE).
- Invested capital of $642 million mainly for the West White Rose project and Terra Nova ALE project in the Atlantic region.

The West White Rose project was approximately 75 percent complete as at December 31, 2023. Since our decision in 2022 to restart the project, we have invested approximately $578 million. We reached a major milestone on the project in the second quarter with the completion of the conical slip form operation for the concrete gravity structure. First oil is expected in 2026.

In late December 2023, we suspended production at the White Rose field as we prepared for the planned SeaRose ALE project. The SeaRose FPSO departed the field for its scheduled dry docking in late January 2024. We expect to resume production at the White Rose field late in the third quarter of 2024.

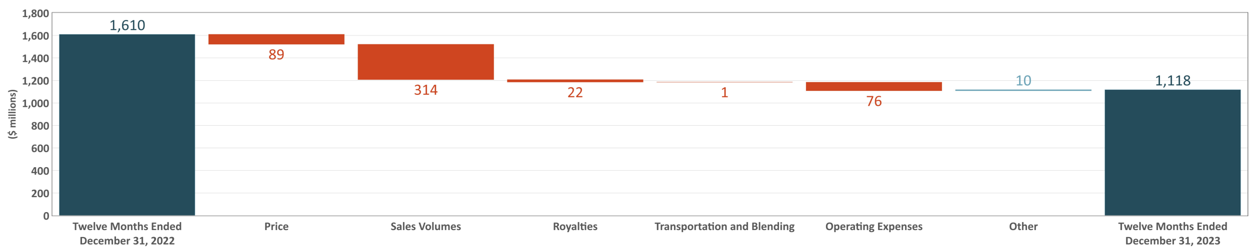
Financial Results

($ millions)	2023 Atlantic	2023 Asia Pacific	2023 Offshore	2022 Atlantic	2022 Asia Pacific	2022 Offshore
Revenues						
Gross Sales	**400**	**1,217**	**1,617**	578	1,442	2,020
Less: Royalties	**15**	**84**	**99**	(3)	80	77
	385	**1,133**	**1,518**	581	1,362	1,943
Expenses						
Transportation and Blending	**16**	**—**	**16**	15	—	15
Operating	**262**	**122**	**384**	204	114	318
Operating Margin (1)	**107**	**1,011**	**1,118**	362	1,248	1,610
Depreciation, Depletion and Amortization			**487**			585
Exploration Expense			**17**			91
(Income) Loss from Equity-Accounted Affiliates			**(57)**			(23)
Segment Income (Loss)			**671**			957

(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

Year Ended December 31, 2023



Operating Results

	2023	2022
Sales Volumes		
Atlantic (Mbbls/d)	9.6	11.3
Asia Pacific (MBOE/d)		
China	40.5	48.2
Indonesia (1)	14.7	10.5
Total Asia Pacific	55.2	58.7
Total Sales Volumes (MBOE/d)	64.8	70.0
Total Realized Price (2) ($/BOE)	81.63	89.72
Atlantic - Light Crude Oil ($/bbl)	113.74	140.65
Asia Pacific (1) ($/BOE)	76.04	79.96
NGLs ($/bbl)	99.73	110.05
Conventional Natural Gas ($/Mcf)	11.71	11.98
Production by Product		
Atlantic - Light Crude Oil (Mbbls/d)	8.2	11.6
Asia Pacific (1)		
NGLs (Mbbls/d)	10.8	12.4
Conventional Natural Gas (MMcf/d)	266.6	277.7
Total Asia Pacific (MBOE/d)	55.2	58.7
Total Production (MBOE/d)	63.4	70.3
Effective Royalty Rate (percent)		
Atlantic	3.7	(0.5)
Asia Pacific (1)	10.3	11.5
Operating Expense (2) ($/BOE)	17.20	12.64
Atlantic	67.93	42.03
Asia Pacific (1)	8.37	7.00
Per Unit DD&A (2) ($/BOE)	25.57	30.76

(1) Reported sales volumes, associated per-unit values and royalty rates reflect Cenovus's 40 percent interest in HCML. Revenues and expenses related to the HCML joint venture are accounted for using the equity method in the Consolidated Financial Statements.

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

Revenues

Price

The price we receive for natural gas sold in Asia is set under long-term contracts. Our realized sales price on light crude oil and NGLs decreased in 2023 compared with 2022, primarily due to lower Brent benchmark pricing.

Production Volumes

Atlantic production decreased 3.4 thousand barrels per day to 8.2 thousand barrels per day in 2023 compared with 2022. The decrease was due to turnaround work on the SeaRose FPSO completed in March and April of 2023 having a larger impact than annual planned maintenance completed in the third quarter in 2022. In addition, the decrease in Cenovus's working interest at the White Rose field and satellite extensions effective May 31, 2022, lowered production year-over-year. Light crude oil production from the White Rose fields is offloaded from the SeaRose FPSO to tankers and stored at an onshore terminal before shipment to buyers, which results in a timing difference between production and sales.

Asia Pacific production decreased 3.5 thousand barrels per day to 55.2 thousand barrels per day in 2023 compared with 2022. The decrease was mainly due to a temporary unplanned outage in the second quarter in China, related to the disconnection of the umbilical by a third-party vessel in early April and reconnected in May. Changes to gas sales agreements at Liwan 3-1 and Liuhua 29-1 in the second quarter of 2022 also resulted in a net decrease in production. The decrease was partially offset by first gas production at the MBH and MDA fields in Indonesia in the fourth quarter of 2022, first gas production at the MAC field in Indonesia in September 2023, and planned maintenance in China in the second and third quarters of 2022 having a larger impact than planned maintenance in June 2023.

Royalties

For the year ended December 31, 2023, Atlantic royalties were $15 million (2022 – recoveries of $3 million). Royalties increased in 2023, as 2022 royalties at the White Rose field included adjustments based on an amended agreement between our working interest partners and the Government of Newfoundland and Labrador.

Royalty rates in China and Indonesia are governed by production sharing contracts in which production is shared with the Chinese and Indonesian governments. The effective royalty rate for the year ended December 31, 2023, declined to 10.3 percent (2022 – 11.5 percent), as a result of the MBH, MDA and MAC fields coming online in 2022 and 2023, having lower rates on initial start-up. The decrease was partially offset by a consumption tax implemented in China in June 2023 impacting royalties on NGLs.

Expenses

Operating

Primary drivers of our Atlantic operating expenses in 2023 were repairs and maintenance, vessel and helicopter costs, and workforce. Operating expenses increased $58 million to $262 million in 2023 compared with 2022. The increase was due to costs associated with preparation and maintenance activities for the Terra Nova FPSO restart, and preparation costs for the SeaRose ALE project. We incurred costs in 2023 and 2022 on the ramp-up of the West White Rose project leading up to the start of major construction in late March 2023. Per-unit operating expenses increased in 2023 compared with 2022 due to lower sales volumes combined with the same factors that impacted total operating expenses.

Primary drivers of our China operating expenses in 2023 were repairs and maintenance, insurance and workforce. Total operating expenses in China increased $8 million to $122 million in 2023, compared with 2022, due to costs related to the umbilical repair. Per-unit operating expenses associated with our assets in China increased compared with 2022 mainly due to lower sales volumes and the same factors that impacted total operating expenses. Per-unit operating expenses associated with our Indonesian assets decreased compared with 2022 mainly due to higher sales volumes.

Transportation

Transportation costs in the Atlantic region were $16 million in 2023 (2022 – $15 million), and includes the cost of transporting crude oil from the SeaRose FPSO unit to onshore via tankers, as well as storage costs.

Netbacks [1]

		2023		
($/BOE, except where indicated)	**Atlantic** ($/bbl)	**China**	**Indonesia** [2]	**Total Offshore**
Sales Price	**113.74**	**82.14**	**59.16**	**81.63**
Royalties	**4.24**	**5.68**	**13.75**	**7.29**
Transportation and Blending	**4.44**	**—**	**—**	**0.66**
Operating Expenses	**67.93**	**7.51**	**10.76**	**17.20**
Netback	**37.13**	**68.95**	**34.65**	**56.48**

		2022		
($/BOE, except where indicated)	Atlantic ($/bbl)	China	Indonesia [2]	Total Offshore
Sales Price	140.65	81.99	70.66	89.72
Royalties	(0.74)	4.57	30.19	7.57
Transportation and Blending	3.79	—	—	0.61
Operating Expenses	42.03	5.62	13.32	12.64
Netback	95.57	71.80	27.15	68.90

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

(2) *Reported sales volumes, associated per-unit values and royalty rates reflect Cenovus's 40 percent interest in HCML. Revenues and expenses related to the HCML joint venture are accounted for using the equity method in the consolidated financial statements.*

Exploration Expense

We recorded exploration expense of $17 million in 2023 (2022 – $91 million). Exploration expense in 2022 was primarily due to a $58 million write-off related to our decision not to pursue development at Block 15/33 in China.

DOWNSTREAM

Canadian Refining

In 2023, we:

- Delivered safe and reliable operations.
- Increased throughput to 100.7 thousand barrels per day (2022 – 92.9 thousand barrels per day), and achieved crude utilization of 90 percent and 95 percent at the Upgrader and Lloydminster Refinery, respectively (2022 – 84 percent and 83 percent, respectively).
- Generated Operating Margin of $675 million, a decrease of $24 million compared with 2022.

Financial Results

($ millions)	2023	2022
Revenues	6,233	7,792
Purchased Product	4,919	6,389
Gross Margin (1)	1,314	1,403
Expenses		
Operating	639	704
Operating Margin	675	699
Depreciation, Depletion and Amortization	185	208
Segment Income (Loss)	490	491

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

Select Operating Results

	2023	2022
Total Canadian Refining		
Heavy Crude Oil Unit Throughput Capacity (1) (Mbbls/d)	110.5	110.5
Heavy Crude Oil Unit Throughput (Mbbls/d)	100.7	92.9
Crude Utilization (percent)	91	84
Total Production (2) (Mbbls/d)	114.2	105.2
Synthetic Crude Oil	47.6	46.0
Asphalt	15.4	13.5
Diesel	12.9	9.3
Other	33.3	31.5
Ethanol	5.0	4.9
Refining Margin (3) ($/bbl)	32.04	33.92
Unit Operating Expense (4) ($/bbl)	12.68	13.91

(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 year ended December 31, 2023, was $4.8 billion (2022 – $3.8 billion, from the Upgrader). Revenue from the Lloydminster Refinery for the year ended December 31, 2023 was $1.0 billion (2022 – $1.1 billion).
(4) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

	2023	2022
Lloydminster Upgrader		
Heavy Crude Oil Unit Throughput Capacity (1) (Mbbls/d)	**81.5**	81.5
Heavy Crude Oil Unit Throughput (Mbbls/d)	**73.1**	68.7
Crude Utilization (percent)	**90**	84
Production (Mbbls/d)	**81.5**	76.0
Refining Margin (2) ($/bbl)	**34.48**	36.04
Unit Operating Expense (3) ($/bbl)	**12.32**	12.65
Upgrading Differential (4) ($/bbl)	**31.14**	32.84
Lloydminster Refinery		
Heavy Crude Oil Unit Throughput Capacity (1) (Mbbls/d)	**29.0**	29.0
Heavy Crude Oil Unit Throughput (Mbbls/d)	**27.6**	24.2
Crude Utilization (percent)	**95**	83
Production (Mbbls/d)	**27.7**	24.3
Refining Margin (2) ($/bbl)	**25.58**	27.91
Unit Operating Expense (3) ($/bbl)	**13.62**	17.49

(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 year ended December 31, 2023, was $4.8 billion (2022 – $3.8 billion, from the Upgrader). Revenue from the Lloydminster Refinery for the year ended December 31, 2023 was $1.0 billion (2022 – $1.1 billion).
(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 2023, Canadian Refining throughput increased 7.8 thousand barrels per day from 2022 to 100.7 thousand barrels per day, and total production increased 9.0 thousand barrels per day to 114.2 thousand barrels per day due to:

- Increased throughput at the Upgrader, which rose 4.4 thousand barrels per day to 73.1 thousand barrels per day, primarily due to a planned turnaround and unplanned operational outages in 2022. The increase was partially offset by temporary unplanned outages in the second and fourth quarters of 2023. Throughput was also impacted by cold weather in the fourth quarter of 2022 until the middle of January 2023.
- Increased throughput at the Lloydminster Refinery, primarily due to the refinery's high utilization in 2023, combined with a planned turnaround in the second quarter of 2022 and an unplanned outage in the third quarter of 2022. Throughput rose 3.4 thousand barrels per day to 27.6 thousand barrels per day compared with 2022.

Revenues and Gross Margin

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

The Lloydminster Refinery processes blended heavy crude oil into asphalt and industrial products. Gross margin is largely dependent on asphalt and industrial products pricing and the cost of heavy crude oil feedstock. Sales from the Lloydminster Refinery 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 2023, approximately 13 percent of total crude oil sales volumes from our Lloydminster thermal and Lloydminster conventional heavy oil assets were sold to our Canadian Refining segment.

In 2023, revenues decreased by $1.6 billion to $6.2 billion due to lower synthetic crude and refined product pricing, combined with the disposition of our retail fuels network in the third quarter of 2022. The decrease was partially offset by higher production volumes from the Upgrader and Lloydminster Refinery. Synthetic crude oil benchmark prices decreased 19 percent to US$79.61 per barrel compared with 2022.

Gross margin decreased $89 million to $1.3 billion in 2023 compared with 2022, primarily driven by the disposition of our retail fuels network in the third quarter of 2022 and the factors discussed above. We increased diesel production relative to synthetic crude in 2023 as we continually optimize production to capture higher margins.

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 2023 were repairs and maintenance, workforce and energy costs.

Total operating costs decreased $65 million to $639 million in 2023 compared with 2022, mainly due to the disposition of our retail fuels network in the third quarter of 2022, lower energy costs and planned turnarounds at the Upgrader and Lloydminster Refinery in the second quarter of 2022. The decrease was partially offset by higher repairs and maintenance spend at the Upgrader in 2023. Per-unit operating costs decreased $1.23 per barrel to $12.68 per barrel in 2023, primarily due to higher throughput and lower energy costs. Per-unit operating expenses only include operating costs and throughput at the Upgrader and Lloydminster Refinery.

U.S. Refining

In 2023, we increased our crude throughput capacity by 129.0 thousand barrels per day through the acquisition of the remaining 50 percent of the Toledo Refinery and the restart of the Superior Refinery, providing further integration of our heavy oil production and refining capabilities.

In addition, we:

- Delivered safe operations and averaged crude utilization of 75 percent (2022 – 80 percent).
- Generated operating margin of $477 million, $1.3 billion lower than 2022 driven by lower market crack spreads and refined product pricing. Refining benchmarks weakened significantly in the fourth quarter of 2023.
- Closed the Toledo Acquisition on February 28, 2023. The acquisition provided us with full ownership and operatorship of the Toledo Refinery and gave us an additional 80.0 thousand barrels per day of throughput capacity.
- Safely restarted, and subsequently returned, the Toledo Refinery to full operations in June. The refinery had a strong second half of the year, demonstrated by crude utilization of 88 percent during that period. Total crude utilization in 2023 was 57 percent (2022 – 45 percent).
- Introduced crude oil at the Superior Refinery in mid-March and restarted the FCCU in early October. Crude utilization for the last two months of 2023, following the restart of the FCCU, was 66 percent.
- Safely completed planned turnarounds at the Wood River Refinery in the spring and at the Borger Refinery in the spring and fall.
- Achieved utilization of 85 percent (2022 – 90 percent) at the Lima Refinery, which was impacted by planned maintenance and unplanned outages in the fourth quarter.
- Invested capital of $602 million, primarily focused on the Superior Refinery rebuild, refining reliability projects and growth spend at the Wood River and Borger refineries, and sustaining activities at the Lima and Toledo refineries.

Financial Results

($ millions)	2023	2022
Revenues [1]	**26,393**	30,218
Purchased Product [1]	**23,354**	26,020
Gross Margin [2]	**3,039**	4,198
Expenses		
Operating	**2,562**	2,346
Realized (Gain) Loss on Risk Management	**—**	112
Operating Margin	**477**	1,740
Unrealized (Gain) Loss on Risk Management	**(17)**	18
Depreciation, Depletion and Amortization	**486**	640
Segment Income (Loss)	**8**	1,082

(1) Comparative periods reflect certain revisions. See Note 39 of the Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

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

Select Operating Results - Consolidated

	2023	2022
Total U.S. Refining		
Crude Oil Unit Throughput Capacity (1) (2) (Mbbls/d)	**635.2**	551.5
Crude Oil Unit Throughput (2) (Mbbls/d)	**459.7**	400.8
Heavy Crude Oil	**173.9**	116.1
Light and Medium Crude Oil	**285.8**	284.7
Crude Utilization (2) (percent)	**75**	80
Total Refined Product Production (Mbbls/d)	**485.0**	419.9
Gasoline	**231.2**	199.8
Distillates (3)	**167.0**	153.4
Asphalt	**19.8**	8.9
Other	**67.0**	57.8
Refining Margin (4) ($/bbl)	**18.12**	28.70
Unit Operating Expense (5) ($/bbl)	**15.27**	16.04

(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.

Select Operating Results - by Refinery

	2023				2022			
	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**	175.0	80.0	49.0	247.5
Crude Oil Unit Throughput (Mbbls/d)	**152.7**	**83.1**	**22.6**	**201.3**	157.9	36.3	—	206.6
Crude Utilization (3) (percent)	**85**	**57**	**61**	**81**	90	45	—	83

(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.

U.S. Refining throughput increased 58.9 thousand barrels per day from 2022 to 459.7 thousand barrels per day, and total refined product production increased 65.1 thousand barrels per day to 485.0 thousand barrels per day, primarily related to the Toledo Acquisition and the restart of the Toledo and Superior refineries. Other factors that impacted throughput and production include:

- Less downtime at the Wood River Refinery, primarily due to the two planned turnarounds in 2022 having a larger impact than the planned turnaround in the spring of 2023, combined with the decision to reduce rates to optimize margins as market conditions dictated in the first quarter of 2022.
- Two planned turnarounds and unplanned outages at the Borger Refinery, which had a larger impact than unplanned outages and the turnaround completed in 2022. The refinery experienced an unplanned operational outage following the fall turnaround which resulted in a slower than expected restart. Combined throughput at the Wood River and Borger refineries decreased 5.3 thousand barrels per day to 201.3 thousand barrels per day in 2023.
- Unplanned outages combined with planned maintenance at the Lima Refinery in the second half of 2023.
- Late in the year, we flexed throughput at our U.S. refineries to optimize our margins.

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. These factors include the type of crude oil feedstock processed, refinery configuration and the proportion of gasoline, distillates and secondary product output, the time lag between the purchase of crude oil feedstock and the processing of that crude oil through the refineries, and the cost of feedstock. Processing less expensive crude relative to WTI creates a feedstock cost advantage. Our feedstock costs are valued on a FIFO accounting basis.

In 2023, the Chicago 3-2-1 crack spread decreased 29 percent to US$24.19 per barrel compared with 2022 and the Group 3 crack spread declined 11 percent to US$29.66 per barrel. Because of the relative strength of the Group 3 crack spread, our Borger and Superior refineries were not impacted as heavily by pricing declines as our other refineries. Average benchmark gasoline prices fell 19 percent to US$97.86 per barrel in 2023 compared with 2022. Average benchmark diesel prices also fell US$34.15 per barrel to US$109.70 per barrel in the year compared with 2022.

Revenues decreased $3.8 billion in 2023 compared with 2022, primarily due to lower refined product pricing, partially offset by higher production. Gross margin decreased $1.2 billion in 2023 compared with 2022, primarily due to lower market crack spreads discussed above, impacts from processing feedstock purchased at higher prices in prior periods, partially offset by higher production and weaker RINs pricing (US$7.04 per barrel in 2023 compared with US$7.72 per barrel in 2022).

Operating Expenses

Primary drivers of operating expenses in 2023 were repairs and maintenance, and workforce.

Operating expenses increased $216 million to $2.6 billion in 2023, compared with 2022, primarily due to the restart of operations at the Toledo and Superior refineries combined with full ownership of the Toledo Refinery. The increases were also due to:

- Increased repairs and maintenance spend at the Lima Refinery, primarily due to higher engineering services and inspection costs, combined with turnaround preparation costs related to the turnaround that was deferred from 2023 to 2024.
- Increased per barrel repairs and maintenance spend at the Borger Refinery, primarily related to the two planned turnarounds that were completed in 2023.
- Increased workforce costs at the Superior Refinery for restart and ramp up activities and higher overall workforce costs related to the Toledo Acquisition.
- Higher electricity pricing, primarily impacting the Lima Refinery, partially offset by lower electricity pricing at the Wood River Refinery.
- Inflationary pressures on maintenance and chemical costs.

The increase was partially offset by lower turnaround costs on a per barrel basis at the Toledo Refinery due to the significant planned turnaround completed in 2022, as well as lower per barrel repairs and maintenance costs at the Wood River Refinery due to the planned turnarounds in 2022. Fuel costs also decreased at the Wood River, Lima and Borger refineries due to the decline in natural gas benchmark pricing.

In 2023, per-unit operating expenses decreased $0.77 per barrel to $15.27 per barrel, compared with 2022, primarily due to higher throughput, partially offset by the increase in operating expenses discussed above.

(Gain) Loss on Risk Management

In 2023, we incurred no realized risk management gains or losses, compared with losses of $112 million in 2022, due to the settlement of benchmark prices relative to our risk management contract prices. In 2023, we recorded unrealized risk management gains of $17 million (2022 – losses of $18 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 related to future periods.

DD&A

U.S. Refining DD&A in 2023 was $486 million, compared with $640 million in 2022. The decrease was primarily due to net impairment charges of $266 million recorded in the fourth quarter of 2022.

CORPORATE AND ELIMINATIONS

Financial Results

($ millions)	2023	2022
Realized (Gain) Loss on Risk Management	**(3)**	31
Unrealized (Gain) Loss on Risk Management	**73**	(89)
General and Administrative	**688**	865
Finance Costs	**671**	820
Interest Income	**(133)**	(81)
Integration, Transaction and Other Costs	**85**	106
Foreign Exchange (Gain) Loss, Net	**(67)**	343
Revaluation (Gain) Loss	**34**	(549)
Re-measurement of Contingent Payments	**59**	162
(Gain) Loss on Divestiture of Assets	**(14)**	(269)
Other (Income) Loss, Net	**(63)**	(532)

Risk Management

In 2023, our corporate risk management activities resulted in realized risk management gains 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 2023 were workforce costs, information technology costs and employee long-term incentive costs. General and administrative expenses decreased in 2023 compared with 2022, primarily due to lower stock-based compensation costs of $97 million (2022 – $373 million). The decrease is partially offset by higher spending on community investment initiatives, workforce and information technology costs.

Finance Costs

Finance costs were lower in 2023 compared with 2022 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 at a discount of $84 million. In the third quarter of 2022, we purchased long-term debt with an aggregate principal amount of US$2.2 billion at a discount of $4 million. 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 2023 was 4.7 percent (2022 – 4.7 percent).

Integration, Transaction and Other Costs

We incurred integration and transaction costs of $57 million related to the Toledo Acquisition. We also incurred costs of $28 million related to modernizing and replacing certain information technology systems, optimizing business processes and standardizing data across the Company. In 2022, we incurred integration and transaction costs of $106 million, primarily related to the integration of Cenovus and Husky.

Foreign Exchange (Gain) Loss, Net

($ millions)	2023	2022
Unrealized Foreign Exchange (Gain) Loss	**(210)**	365
Realized Foreign Exchange (Gain) Loss	**143**	(22)
	(67)	343

In 2023, unrealized foreign exchange gains, compared with losses in 2022, were mainly related to the translation of U.S. denominated debt caused by a stronger Canadian dollar at December 31, 2023. Realized foreign exchange losses in 2023 were primarily due to the settlement of fixed-term debt. Realized foreign exchange gains in 2022 were primarily related to working capital, partially offset by a lower realized foreign exchange loss on the settlement of fixed-term debt in 2023 compared with 2022.

Revaluation (Gain) Loss

As required by IFRS 3, "*Business Combinations*", when an acquirer achieves control in stages, the previously held interest is remeasured to fair value at the acquisition date with any gain or loss recognized in net earnings (loss). Refer to Note 5 of the Consolidated Financial Statements for further details. Cenovus recognized a revaluation loss of $34 million in 2023 as part of the Toledo Acquisition. In the third quarter of 2022, Cenovus recognized a revaluation gain of $549 million as part of the Sunrise Acquisition.

Re-measurement of Contingent Payments

In connection with the Sunrise Acquisition, Cenovus agreed to make quarterly variable payments to bp Canada for up to eight quarters subsequent to August 31, 2022, if the average WCS crude oil price in a quarter exceeds $52.00 per barrel. The maximum cumulative variable payment is $600 million. Refer to Note 26 of the 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 December 31, 2023, the fair value of the variable payment was estimated to be $164 million, resulting in non-cash re-measurement losses of $59 million in the year ended December 31, 2023 (2022 – gains of $89 million).

For the year ended December 31, 2023, we paid $299 million under this agreement (2022 – $nil). The payment of $107 million for the quarter ended November 30, 2023, was made on January 29, 2024. The payments are recognized in cash from (used in) investing activities. As of December 31, 2023, average estimated WCS forward pricing for the remaining term of the variable payment is approximately $71.86 per barrel. As at December 31, 2023, the remaining payments are considered current liabilities. The maximum payment over the remaining term of the contract is $194 million.

The contingent payment associated with the transaction with ConocoPhillips related to its 50 percent interest in the FCCL Partnership ended on May 17, 2022, and the final payment was made in July 2022. We recorded a non-cash remeasurement loss of $251 million associated with this payment in 2022.

(Gain) Loss on Divestiture of Assets

We had no material divestitures in 2023. In 2022, we recognized a gain on divestiture of assets of $269 million due to the sale of our Tucker and Wembley assets, the divestiture of 12.5 percent of our interest in the White Rose field and satellite extensions, and the retail divestiture.

Other (Income) Loss, Net

In 2023, other income was $63 million (2022 – $532 million). Other income in 2022 was primarily due to insurance proceeds related to the 2018 incidents at the Superior Refinery and in the Atlantic region, combined with funding received under the Government of Alberta’s Site Rehabilitation Program.

DD&A

The largest drivers of corporate depreciation include information technology assets, right-of-use buildings and leasehold improvements. DD&A for the year ended December 31, 2023, was $107 million, compared with $113 million in 2022.

Income Taxes

($ millions)	**2023**	2022
Current Tax		
Canada	**1,041**	1,252
United States	**(109)**	104
Asia Pacific	**224**	262
Other International	**25**	21
Total Current Tax Expense (Recovery)	**1,181**	1,639
Deferred Tax Expense (Recovery)	**(250)**	642
	931	2,281

The decline in current income tax expense for 2023 was primarily due to lower earnings compared with 2022. The effective tax rate in 2023 was 18.5 percent (2022 – 26.1 percent). The lower rate is primarily due to the deferred tax recovery recorded in 2023 related to the recognition of tax attributes acquired in 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.

QUARTERLY RESULTS

	2023				2022			
($ millions, except where indicated)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Average Commodity Prices [1] (US$/bbl)								
Dated Brent	**84.05**	86.76	78.39	81.27	88.71	100.85	113.78	101.41
WTI	**78.32**	82.26	73.78	76.13	82.65	91.55	108.41	94.29
WCS at Hardisty	**56.43**	69.35	58.74	51.36	56.99	71.69	95.61	79.76
Differential WTI-WCS at Hardisty	**21.89**	12.91	15.04	24.77	25.66	19.86	12.80	14.53
Chicago 3-2-1 Crack Spread [2]	**13.24**	26.06	28.57	28.88	32.87	38.87	46.50	18.35
RINs	**4.77**	7.42	7.72	8.20	8.54	8.11	7.80	6.44
Upstream Production Volumes								
Bitumen (Mbbls/d)	**595.1**	586.0	554.6	570.7	593.5	568.2	540.3	578.8
Heavy Crude Oil (Mbbls/d)	**17.5**	15.6	17.0	16.8	15.8	16.8	16.4	16.2
Light Crude Oil (Mbbls/d)	**15.8**	15.2	10.1	15.3	17.1	16.0	20.8	21.9
NGLs (Mbbls/d)	**34.2**	35.6	26.7	33.4	38.5	32.1	36.7	37.6
Conventional Natural Gas (MMcf/d)	**876.3**	867.4	729.4	857.0	852.0	868.7	882.2	865.3
Total Production Volumes (MBOE/d)	**808.6**	797.0	729.9	779.0	806.9	777.9	761.5	798.6
Downstream Crude Oil Unit Throughput [3] (Mbbls/d)	**579.1**	664.3	537.8	457.9	473.3	533.5	457.3	501.8
Downstream Production Volumes (Mbbls/d)	**627.4**	706.0	571.9	487.7	506.3	572.6	482.1	538.0
Revenues	**13,134**	14,577	12,231	12,262	14,063	17,471	19,165	16,198
Operating Margin [4]	**2,151**	4,369	2,400	2,102	2,782	3,339	4,678	3,464
Cash From (Used in) Operating Activities	**2,946**	2,738	1,990	(286)	2,970	4,089	2,979	1,365
Adjusted Funds Flow [4]	**2,062**	3,447	1,899	1,395	2,346	2,951	3,098	2,583
Per Share - Basic [4] ($)	**1.10**	1.82	1.00	0.73	1.22	1.53	1.57	1.30
Per Share - Diluted [4] ($)	**1.09**	1.81	0.98	0.71	1.19	1.49	1.53	1.27
Capital Investment	**1,170**	1,025	1,002	1,101	1,274	866	822	746
Free Funds Flow [4]	**892**	2,422	897	294	1,072	2,085	2,276	1,837
Excess Free Funds Flow [4]	**471**	1,989	505	(499)	786	1,756	2,020	2,615
Net Earnings (Loss) [5]	**743**	1,864	866	636	784	1,609	2,432	1,625
Per Share - Basic ($)	**0.39**	0.98	0.45	0.33	0.40	0.83	1.23	0.81
Per Share - Diluted ($)	**0.39**	0.97	0.44	0.32	0.39	0.81	1.19	0.79
Total Assets	**53,915**	54,427	53,747	54,000	55,869	55,086	55,894	55,655
Total Long-Term Liabilities	**18,993**	18,395	19,831	19,917	20,259	19,378	20,742	21,889
Long-Term Debt, Including Current Portion	**7,108**	7,224	8,534	8,681	8,691	8,774	11,228	11,744
Net Debt	**5,060**	5,976	6,367	6,632	4,282	5,280	7,535	8,407
Cash Returns to Shareholders	**731**	1,225	584	258	807	873	1,233	544
Common Shares – Base Dividends	**261**	264	265	200	201	205	207	69
Base Dividends Per Common Share ($)	**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	**350**	361	310	40	387	659	1,018	466
Payment for Purchase of Warrants	**111**	600	—	—	—	—	—	—
Preferred Share Dividends	**9**	—	9	18	—	9	8	9

(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) Represents Cenovus's net interest in refining operations.
(4) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(5) Net earnings (loss) for all periods in the table above is the same as net earnings (loss) from continuing operations.

The fourth quarter was highlighted by strong upstream performance, planned and unplanned outages in our downstream business, and financial results reflecting a declining commodity price environment.

- Upstream production averaged 808.6 thousand BOE per day, an increase from 797.0 thousand BOE per day in the third quarter of 2023, and our highest quarterly average since the fourth quarter of 2021.
- Downstream throughput decreased to 579.1 thousand barrels per day from 664.3 thousand barrels per day in the third quarter, largely driven by the planned turnaround and delayed startup at the Borger Refinery, and planned and unplanned outages at the Lima Refinery in the fourth quarter.
- WCS at Hardisty decreased from US$69.35 per barrel in the third quarter to US$56.43 per barrel, including a decrease in December to US$45.54 per barrel.
- The Chicago 3-2-1 crack spread declined significantly from US$26.06 per barrel in the third quarter to US$13.24 per barrel, the lowest quarterly average since the first quarter of 2021. The December 2023 average Chicago 3-2-1 crack spread was US$7.65 per barrel, the lowest monthly average since 2020.
- Operating Margin fell to $2.2 billion from $4.4 billion in the third quarter of 2023 and Adjusted Funds Flow decreased to $2.1 billion from $3.4 billion in the third quarter.
- We reduced Net Debt by $916 million from September 30, 2023, primarily due to cash from operating activities of $2.9 billion, capital investment of $1.2 billion and cash returns to shareholders of $731 million.

Fourth Quarter 2023 Results Compared with the Fourth Quarter 2022

The summary below compares financial and operating results for the three months ended December 31, 2023, compared with the same period in 2022.

Upstream Production Volumes

Total upstream production increased 1.7 thousand BOE per day in the fourth quarter of 2023 compared with the same period in 2022, primarily due to:

- Successful results from redevelopment programs at our Sunrise and Lloydminster thermal assets.
- Production from the MAC field in Indonesia that started in the third quarter of 2023, and the MBH and MDA fields that came online part way through the fourth quarter of 2022.
- The impact of well pads brought online at Foster Creek in the second and third quarters of 2023.
- The Terra Nova FPSO resuming production in late November.

The increases were partially offset by lower production at Christina Lake due to the timing of new wells pads in 2023 in addition to the suspension of production at the White Rose field as we prepared for the planned SeaRose ALE project in late December.

Downstream Refining Throughput and Production

Canadian Refining throughput increased 6.0 thousand barrels per day to 100.3 thousand barrels per day and refined product production increased 5.7 thousand barrels per day to 113.3 thousand barrels per day compared with 2022. Utilization at the Upgrader and Lloydminster Refinery was 90 percent and 92 percent, respectively (2022 – 84 percent and 89 percent, respectively). Operations were solid in the fourth quarter of 2023 compared with cold weather impacts and unplanned operational outages in the fourth quarter of 2022. The increases were partially offset by an unplanned outage at the Upgrader in October, which returned to full rates in November.

U.S. Refining throughput increased 99.8 thousand barrels per day to 478.8 thousand barrels per day and total refined product production increased 115.4 thousand barrels per day to 514.1 thousand barrels per day compared with 2022, primarily due to:

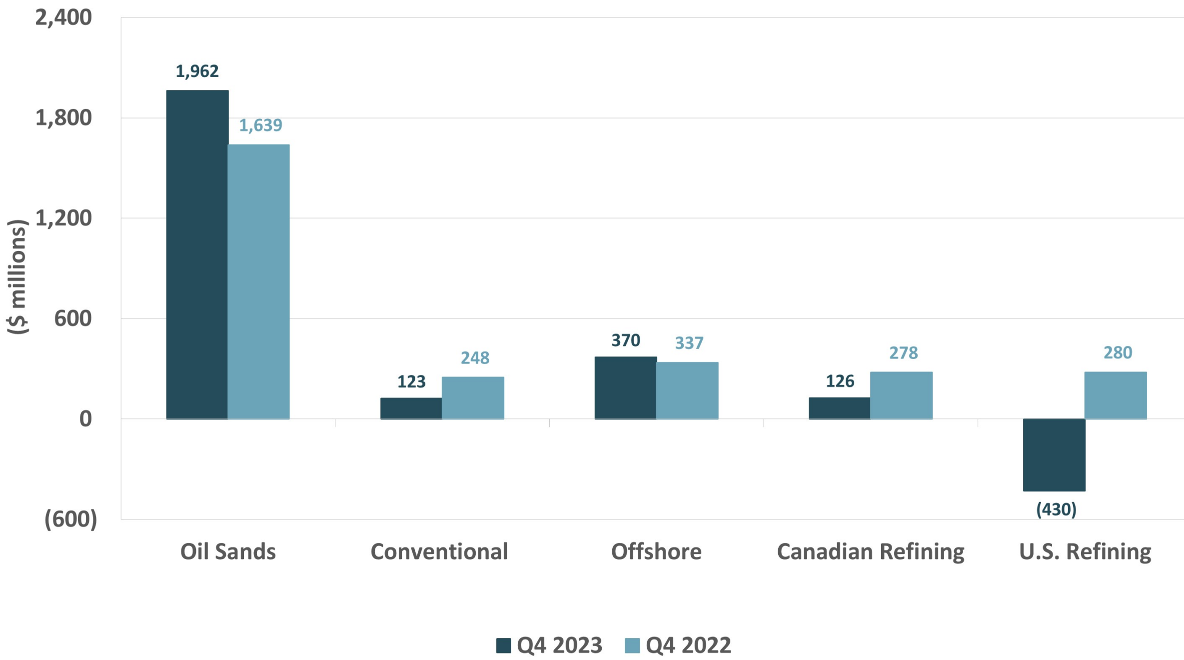
- An increase in throughput at the Toledo Refinery of 138.4 thousand barrels per day due to the Toledo Acquisition and the restart of the Toledo Refinery.
- Throughput of 32.4 thousand barrels per day because of the restart of the Superior Refinery.

The increases in throughput and production were partially offset by:

- The planned turnaround at the Borger Refinery completed in the fourth quarter of 2023 and an unplanned operational outage following the turnaround which resulted in slower than expected ramp up.
- Planned maintenance and a temporary unplanned outage at the Lima Refinery in the fourth quarter of 2023.
- Our ability to flex throughput across our refining network to optimize our margins.

Operating Margin

Three Months Ended December 31, 2023 and 2022



Operating Margin decreased $631 million to $2.2 billion in the fourth quarter of 2023, compared with 2022 primarily due to significantly lower market crack spreads and lower synthetic crude oil prices relative to crude oil feedstock impacting our downstream business. In addition, we processed feedstock from inventory purchased at higher prices in prior periods and recorded non-cash inventory write-downs on our refined products inventory in the fourth quarter. The decreases were partially offset by higher throughput and refined product production due to the Toledo Acquisition and the start-up of the Toledo and Superior refineries. Also offsetting the decrease was a higher Operating Margin from our upstream business mainly due to increased sales volumes, and higher realized pricing from the Oil Sands segment.

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

Cash from operating activities of $2.9 billion in the fourth quarter of 2023 was consistent with 2022, as the decrease in Operating Margin discussed above, was partially offset by changes in non-cash working capital. The net change in non-cash working capital in the fourth quarter of 2023 was $949 million, compared with a net change of $673 million in the fourth quarter of 2022. The increase in 2023 was mainly due to decreases in accounts receivable and inventory, partially offset by a decrease in accounts payable, primarily due to falling commodity prices.

Adjusted Funds Flow decreased to $2.1 billion in the fourth quarter of 2023 compared with $2.3 billion in 2022, primarily due to lower Operating Margin discussed above.

Net Earnings (Loss)

Net earnings were $743 million in the fourth quarter of 2023 compared with $784 million in 2022. The decrease was due to lower Operating Margin, partially offset by lower general and administrative costs and DD&A.

Capital Investment

Capital investment in the fourth quarter of 2023 was $1.2 billion (2022 – $1.3 billion), mainly related to:

- Sustaining activities and the drilling of stratigraphic test wells as part of our integrated winter program in the Oil Sands segment, in addition to the tie-back of Narrows Lake to Christina Lake and other growth projects at Foster Creek and Sunrise.
- Drilling, completion, tie-in and infrastructure projects in the Conventional segment.
- The West White Rose project in the Atlantic region.
- Sustaining activities at the Lima, Borger and Toledo refineries.

OIL AND GAS RESERVES

As at December 31, 2023 (before royalties) [1]	Bitumen [2] (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas [3] (Bcf)	Total (MMBOE)
Total Proved	5,411	38	74	2,062	**5,866**
Probable	2,487	125	40	1,100	**2,836**
Total Proved Plus Probable	7,899	163	114	3,162	**8,702**

As at December 31, 2022 (before royalties) [1]	Bitumen [2] (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas [3] (Bcf)	Total (MMBOE)
Total Proved	5,592	42	82	2,194	**6,082**
Probable	2,448	129	39	1,029	**2,787**
Total Proved Plus Probable	8,040	171	121	3,223	**8,869**

(1) Totals may not sum due to rounding.
(2) Includes heavy crude oil that is not material.
(3) Includes shale gas that is not material.

Developments in 2023 compared with 2022 include:

- Bitumen gross total proved and gross total proved plus probable reserves decreased by 181 million barrels and 141 million barrels, respectively. The changes were due to current year production and recovery factor adjustments at Christina Lake and Foster Creek, partially offset by additions from regulatory approvals at Foster Creek and Lloydminster thermal, updates to the Sunrise development plan, an acquisition in the Oil Sands segment and improved recovery performance at Lloydminster thermal.
- Light and medium oil gross total proved and gross total proved plus probable reserves decreased by 4 million barrels and 8 million barrels, respectively. The changes were due to current year production and technical revisions, partially offset by additions from updates to the Atlantic region and Conventional segment development plans.
- NGLs gross total proved and gross total proved plus probable reserves decreased by 8 million barrels and 7 million barrels , respectively. The changes were due to current year production, partially offset by additions from updates to the Conventional segment development plans.
- Conventional natural gas gross total proved and gross total proved plus probable reserves decreased by 132 billion cubic feet and 61 billion cubic feet, respectively. The changes were due to current year production, partially offset by updates to the Conventional segment development plans and updates to gas contracts in Asia Pacific.

The reserves data is presented as at December 31, 2023, using an average of the forecast prices, inflation and exchange rate ("Average Forecast") by McDaniel & Associates Consultants Ltd., GLJ Ltd. and Sproule Associates Limited. The Average Forecast is dated January 1, 2024. Comparative information as at December 31, 2022 uses the January 1, 2023, Average Forecast.

Additional information with respect to the evaluation and reporting of our reserves in accordance with National Instrument 51-101, *"Standards of Disclosure for Oil and Gas Activities"* is contained in our AIF for the year ended December 31, 2023. Our AIF is available on SEDAR+ at sedarplus.ca, on EDGAR at sec.gov and on our website at cenovus.com. Material risks and uncertainties associated with estimates of reserves are discussed in the Risk Management and Risk Factors section and the Advisory section of this MD&A.

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. The cost and availability of borrowing and access to sources of liquidity and capital are dependent on current credit ratings and market conditions.

($ millions)	**2023**	2022
Cash From (Used In)		
Operating Activities	**7,388**	11,403
Investing Activities	**(5,295)**	(2,314)
Net Cash Provided (Used) Before Financing Activities	**2,093**	9,089
Financing Activities	**(4,313)**	(7,676)
Effect of Foreign Exchange on Cash and Cash Equivalents	**(77)**	238
Increase (Decrease) in Cash and Cash Equivalents	**(2,297)**	1,651

As at December 31,	**2023**	2022
Cash and Cash Equivalents	**2,227**	4,524
Total Debt	**7,287**	8,806

Cash From (Used in) Operating Activities

For the year ended December 31, 2023, cash from operating activities was $7.4 billion (2022 – $11.4 billion). The decrease was primarily due to lower Operating Margin and changes in non-cash working capital. During the year ended December 31, 2023, the net change in non-cash working capital decreased cash by $1.2 billion, primarily driven by the payment of the December 31, 2022, income tax liability of $1.2 billion in the first quarter of 2023.

Cash From (Used in) Investing Activities

Cash used in investing activities increased significantly in 2023 compared with 2022. The increase was partly due to higher capital spend, including acquisition capital. Acquisition capital was higher in 2023 with the closing of the Toledo Acquisition in the first quarter, which was partially offset by the Sunrise Acquisition in the third quarter of 2022. The increase was also due to minimal proceeds from divestitures in 2023, compared with the sales of our retail fuels network and the Tucker and Wembley assets in 2022. The net change in non-cash working capital, which includes the Sunrise contingent payments, decreased cash in 2023.

Cash From (Used in) Financing Activities

In 2023, we reduced debt through the purchase of US$1.0 billion of certain unsecured notes due between 2029 and 2047 at a discount of $84 million. In 2022, we purchased long-term debt of US$2.6 billion and C$750 million. We also returned $2.8 billion to shareholders in 2023 compared with $3.5 billion in 2022.

In 2023, we issued $58 million, net, of short-term borrowings (2022 – $34 million, net).

Working Capital

Excluding the current portion of the contingent payments, our adjusted working capital at December 31, 2023, was $3.7 billion (December 31, 2022 – $4.7 billion).

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

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

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

	Three Months Ended December 31,		Year Ended December 31,	
($ millions)	**2023**	2022	**2023**	2022
Cash From (Used in) Operating Activities	**2,946**	2,970	**7,388**	11,403
(Add) Deduct:				
Settlement of Decommissioning Liabilities	**(65)**	(49)	**(222)**	(150)
Net Change in Non-Cash Working Capital	**949**	673	**(1,193)**	575
Adjusted Funds Flow	**2,062**	2,346	**8,803**	10,978
Capital Investment	**1,170**	1,274	**4,298**	3,708
Free Funds Flow	**892**	1,072	**4,505**	7,270
Add (Deduct):				
Base Dividends Paid on Common Shares	**(261)**	(201)		
Dividends Paid on Preferred Shares	**(9)**	—		
Settlement of Decommissioning Liabilities	**(65)**	(49)		
Principal Repayment of Leases	**(72)**	(74)		
Acquisitions, Net of Cash Acquired	**(14)**	(7)		
Proceeds From Divestitures	**—**	45		
Excess Free Funds Flow	**471**	786		

Returns to Shareholders Target

Maintaining a strong balance sheet with the resilience to withstand price volatility and capitalize on opportunities throughout the commodity price cycle is a key element of Cenovus's capital allocation framework. We have set an ultimate Net Debt Target of $4 billion, which serves as our floor on Net Debt. Our $4 billion Net Debt Target represents a Net Debt to Adjusted Funds Flow Ratio Target of approximately 1.0 times at the bottom of the commodity pricing cycle. We plan to return incremental value to shareholders through share buybacks and/or variable dividends as follows:

- When Net Debt is less than $9 billion and above $4 billion at quarter-end, we will target to allocate 50 percent of the Excess Free Funds Flow achieved in the following quarter to shareholder returns, while still continuing to deleverage the balance sheet until we reach the Net Debt Target of $4 billion.
- When Net Debt is above $9 billion at quarter-end, we plan to allocate all of the following quarter's Excess Free Funds Flow to deleveraging the balance sheet.
- When Net Debt is at the $4 billion floor at quarter-end, we will target to return 100 percent of the following quarter's Excess Free Funds Flow to shareholder returns.

Share buybacks are executed opportunistically, driven by return thresholds. Where the value of share buybacks in a quarter is less than the targeted value of returns, the remainder will be delivered through a variable dividend payable for that quarter, if the remainder is greater than $50 million. Where the value of share buybacks in a quarter is greater than or equal to the targeted value of returns, no variable dividend will be paid for that quarter.

On September 30, 2023, our long-term debt was $7.2 billion, and our Net Debt position was $6.0 billion. Therefore, our returns to shareholders target for the three months ended December 31, 2023, was 50 percent of the current quarter's Excess Free Funds Flow of $471 million. Our target return was $236 million, which was exceeded through share buybacks of $350 million and warrant purchase payments of $111 million. As such, no variable dividend was declared for the first quarter of 2024.

	Three Months Ended			
($ millions)	**December 31, 2023**	September 30, 2023	June 30, 2023	March 31, 2023
Excess Free Funds Flow	**471**	1,989	505	(499)
Target Return	**236**	995	253	—
Less: Purchase of Common Shares Under NCIB	**(350)**	(361)	(310)	(40)
Less: Payment for Purchase of Warrants	**(111)**	(600)	—	—
Amount Available for Variable Dividend	**—**	34	—	—

At December 31, 2023, our Net Debt position was $5.1 billion and as a result, our returns to shareholders target for the three months ended March 31, 2024, will be 50 percent of the first quarter's Excess Free Funds Flow.

Short-Term Borrowings

As at December 31, 2023, the Company's proportionate share drawn on the WRB uncommitted demand facilities was US$135 million (C$179 million) (December 31, 2022 – the Company's proportionate share drawn was US$85 million (C$115 million)). There were no direct borrowings on our uncommitted demand facilities as at December 31, 2023, or December 31, 2022.

Long-Term Debt, Including Current Portion

Long-term debt, including the current portion, as at December 31, 2023, was $7.1 billion (December 31, 2022 – $8.7 billion). This includes U.S. dollar denominated unsecured notes of US$3.8 billion, or C$5.0 billion (December 31, 2022 – US$4.8 billion, or C$6.5 billion) and Canadian dollar denominated unsecured notes of $2.0 billion (December 31, 2022 – $2.0 billion). The decrease in long-term debt was primarily due to the third quarter purchase of unsecured notes with an aggregate principal amount of US$1.0 billion at a discount of $84 million.

As at December 31, 2023, we were in compliance with all of the terms of our debt agreements.

Available Sources of Liquidity

The following sources of liquidity are available as at December 31, 2023:

($ millions)	Maturity	Amount Available
Cash and Cash Equivalents	**n/a**	**2,227**
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**	**1,071**
WRB (3)	**n/a**	**119**

(1) No amounts were drawn on the committed credit facility as at December 31, 2023 (December 31, 2022 – $nil).

(2) Our uncommitted demand facilities include $1.7 billion, of which $1.4 billion may be drawn for general purposes, or the full amount can be available to issue letters of credit. As at December 31, 2023, there were outstanding letters of credit aggregating to $364 million (December 31, 2022 – $490 million) and no direct borrowings (December 31, 2022 – $nil).

(3) Represents Cenovus's proportionate share of US$225 million available to cover short-term working capital requirements. As at December 31, 2023, US$135 million (C$179 million) of this capacity was drawn (December 31, 2022 – US$85 million (C$115 million)).

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

Base Shelf Prospectus

On November 3, 2023, Cenovus filed a base shelf prospectus that allows the Company 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 the Net Debt to Capitalization Ratio, Net Debt to Adjusted Funds Flow Ratio and Net Debt to Adjusted EBITDA Ratio. Refer to Note 25 of the Consolidated Financial Statements for further details.

We define Net Debt as short-term borrowings and the current and long-term portions of long-term debt, net of cash and cash equivalents and short-term investments. The components of the ratios include Capitalization, Adjusted Funds Flow and Adjusted EBITDA. We define Capitalization as Net Debt plus Shareholders Equity. We define Adjusted Funds Flow, as used in the Net Debt to Adjusted Funds Flow Ratio, as cash from (used in) operating activities, less settlement of decommissioning liabilities and net change in operating non-cash working capital calculated on a trailing twelve-month basis. We define Adjusted EBITDA, as used in the Net Debt to Adjusted EBITDA Ratio, as net earnings (loss) before finance costs, net of capitalized interest, interest income, income tax expense (recovery), DD&A, E&E asset write-downs, goodwill impairments, (income) loss from equity-accounted affiliates, unrealized (gain) loss on risk management, net foreign exchange (gain) loss, revaluation (gain) loss, re-measurement of contingent payments, (gain) loss on divestiture of assets, and net other (income) loss calculated on a trailing twelve-month basis. These ratios are used to steward our overall debt position and are measures of our overall financial strength.

As at	December 31, 2023	December 31, 2022
Net Debt to Capitalization Ratio (percent)	**15**	13
Net Debt to Adjusted Funds Flow Ratio (times)	**0.6**	0.4
Net Debt to Adjusted EBITDA Ratio (times)	**0.5**	0.3

Our Net Debt to Adjusted Funds Flow Ratio and our Net Debt to Adjusted EBITDA Ratio Targets are approximately 1.0 times at the bottom of the commodity price cycle, which we believe is approximately US$45 per barrel WTI. This ratio may fluctuate periodically outside the range due to factors such as persistently high or low commodity prices. Our objective is to maintain a high level of capital discipline and manage our capital structure to help ensure we have sufficient liquidity through all stages of the economic cycle. To ensure financial resilience, we may, among other actions, adjust capital and operating spending, draw down on our credit facilities or repay existing debt, adjust dividends paid to shareholders, purchase our common shares for cancellation, issue new debt, or issue new shares.

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

Our Net Debt to Adjusted Funds Flow Ratio and Net Debt to Adjusted EBITDA Ratio as at December 31, 2023, increased compared with December 31, 2022, as a result of higher Net Debt and lower Operating Margin. See the Operating and Financial Results section of this MD&A for more information on Operating Margin and Net Debt.

Share Capital and Stock-Based Compensation Plans

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

As at December 31, 2023, there were approximately 1,871.9 million common shares outstanding (December 31, 2022 – 1,909.2 million common shares) and 36 million preferred shares outstanding (December 31, 2022 – 36 million preferred shares). Refer to Note 30 of the Consolidated Financial Statements for further details.

On November 7, 2023, the Company received approval from the TSX to renew the Company's NCIB program to purchase up to 133.2 million common shares from November 9, 2023, to November 8, 2024.

	2023	2022
Common Shares Purchased and Cancelled Under NCIB (millions of common shares)	**43.6**	112.5
Weighted Average Price per Common Share ($)	**24.32**	22.49
Purchase of Common Shares Under NCIB ($ millions)	**(1,061)**	(2,530)

From January 1, 2024, to February 12, 2024, the Company purchased an additional 4.3 million common shares for $92 million. As at February 12, 2024, the Company can further purchase up to 118.3 million common shares under the existing NCIB.

As at December 31, 2023, there were approximately 7.6 million Cenovus Warrants outstanding (December 31, 2022 – 55.7 million Cenovus Warrants). Each Cenovus Warrant entitles the holder to acquire one common share for a period of five years from the date of issue at an exercise price of $6.54 per common share. The Cenovus Warrants expire on January 1, 2026. Refer to Note 30 of the Consolidated Financial Statements for further details.

On June 14, 2023, we purchased and cancelled 45.5 million outstanding Cenovus Warrants. The price for each warrant purchased represented a price of $22.18 per common share, less the warrant exercise price of $6.54 per common share, for a total of $711 million. We also recorded $2 million of transaction costs. This purchase represented 84 percent of Cenovus's outstanding warrants. The full warrant purchase obligation was paid by December 31, 2023.

Refer to Note 32 of the 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 February 12, 2024	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares	**1,867,826**	**n/a**
Cenovus Warrants	**7,614**	**n/a**
Series 1 First Preferred Shares	**10,740**	**n/a**
Series 2 First Preferred Shares	**1,260**	**n/a**
Series 3 First Preferred Shares	**10,000**	**n/a**
Series 5 First Preferred Shares	**8,000**	**n/a**
Series 7 First Preferred Shares	**6,000**	**n/a**
Stock Options	**12,852**	**7,615**
Other Stock-Based Compensation Plans	**19,230**	**1,772**

Common Share Dividends

In 2023, we paid base dividends of $990 million or $0.525 per common share (2022 – $682 million or $0.350 per common share). No variable dividend was declared or paid in 2023.

The Board declared a first quarter base dividend of $0.140 per common share, payable on March 28, 2024, to common shareholders of record as at March 15, 2024. The declaration of common share dividends is at the sole discretion of the Board and is considered quarterly.

Cumulative Redeemable Preferred Share Dividends

In 2023, dividends of $36 million were paid on the series 1, 2, 3, 5 and 7 preferred shares (2022 – $26 million). The declaration of preferred share dividends is at the sole discretion of the Board and is considered quarterly. The Board declared a first quarter dividend on the series 1, 2, 3, 5 and 7 preferred shares of $9 million, payable on April 1, 2024, to preferred shareholders of record as at March 15, 2024.

Contractual Obligations and Commitments

We have obligations for goods and services entered into in the normal course of business. Obligations that have original maturities of less than one year are excluded from the table below.

Our total commitments were $28.8 billion as at December 31, 2023 (December 31, 2022 – $33.0 billion). Total commitments decreased from December 31, 2022, primarily due to the cancellation of the contract terms of certain product purchase contracts, combined with the use of contracts. The decrease was partially offset by increased tolls due to the Trans Mountain Pipeline Expansion and commitments acquired as part of the Toledo Acquisition.

As at December 31, 2023, our total commitments included commitments with HMLP of $2.1 billion related to long-term transportation and storage commitments.

As at December 31, 2023 ($ millions)	2024	2025	2026	2027	2028	Thereafter	Total
Commitments							
Transportation and Storage [(1)]	2,018	1,927	1,680	1,663	1,641	15,738	**24,667**
Product Purchases	617	—	—	—	—	—	**617**
Real Estate	57	57	59	63	58	604	**898**
Obligation to Fund HCML	94	94	94	89	52	90	**513**
Other Long-Term Commitments [(2)]	417	194	184	175	166	965	**2,101**
Total Commitments	3,203	2,272	2,017	1,990	1,917	17,397	**28,796**
Long-Term Debt (Principal and Interest)	313	489	303	1,523	1,484	7,145	**11,257**
Decommissioning Liabilities	259	296	291	286	283	6,063	**7,478**
Contingent Payment	168	—	—	—	—	—	**168**
Lease Liabilities (Principal and Interest) [(3)]	438	367	345	294	275	2,635	**4,354**
Total Commitments and Obligations	4,381	3,424	2,956	4,093	3,959	33,240	**52,053**

(1) Includes transportation commitments that are subject to regulatory approval or were approved, but are not yet in service of $13.0 billion (December 31, 2022 – $9.1 billion). Terms are up to 20 years on commencement. Estimated tolls are subject to change pending review by the Canada Energy Regulator.

(2) The Company acquired $538 million of commitments as part of the Toledo Acquisition on February 28, 2023.

(3) Lease contracts related to railcars, barges, vessels, pipelines, caverns, storage tanks, office space, our commercial fuels network and other refining and field equipment.

As at December 31, 2023, outstanding letters of credit issued as security for performance under certain contracts totaled $364 million (2022 – $490 million). Subsequent to December 31, 2023, Cenovus entered into a new transportation commitment for $587 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 Consolidated Financial Statements.

Transactions with Related Parties

Cenovus holds a 35 percent interest in HMLP. As the operator of the assets held by HMLP, we provide management services for which we recover shared service costs in accordance with our profit sharing agreement. We are also the contractor for HMLP and construct its assets on a cost recovery basis with certain restrictions. For the year ended December 31, 2023, we charged HMLP $160 million for construction and management services (2022 – $188 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 year ended December 31, 2023, we incurred costs of $295 million for the use of HMLP's pipeline systems, as well as for transportation and storage services (2022 – $263 million).

RISK MANAGEMENT AND RISK FACTORS

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.

Our Enterprise Risk Management ("ERM") program drives the identification, measurement, prioritization, and management of our risks and is integrated with the Cenovus Operations Integrity Management System ("COIMS"). In addition, we continuously monitor our risk profile as well as industry best practices.

Risk Governance

The ERM Policy, approved by our Board, outlines our risk management principles and expectations, as well as the roles and responsibilities of all staff. Building on the ERM Policy, we have established risk management standards, a risk management framework and risk assessment tools, including the Cenovus Risk Matrix. Our risk management framework contains the key attributes recommended by the International Organization for Standardization ("ISO") in its ISO 31000 – Risk Management Guidelines. The results of our ERM program are documented in semi-annual risk reports presented to our Board as well as through regular updates.

Risk Factors

The following discussion describes the financial, operational, regulatory, environmental, reputational, climate change related, and other risks related to Cenovus. Each risk identified in this MD&A may individually, or in combination with other risks, have a material impact on, among other things, our business, financial condition, results of operations, cash flows, reputation, access to capital, cost of borrowing, access to liquidity, ability to fund share repurchases, dividend payments and/or business plans, and/or the market price of our securities. These factors should be considered when investing in securities of Cenovus.

Financial Risk

Commodity Prices

Our financial performance is significantly dependent on the prevailing prices of crude oil, refined products, natural gas and NGLs. Prices for crude oil, refined products, natural gas and NGLs are impacted by a number of factors, including, but not limited to: global and regional supply of and demand for these commodities; the ability of producers and governments to replace reduced supply; transportation restrictions; processing and export capacity; export restrictions; domestic and global economic conditions; inflation and changes to interest rates; increased tariffs; central bank policies; market competitiveness; the actions of OPEC and other oil exporting nations, including, but not limited to, compliance or non-compliance with quotas agreed upon by OPEC members and decisions by OPEC not to impose production quotas on its members; the release and refilling of the U.S. Strategic Petroleum Reserves; developments related to the market for these commodities; inventory levels of these commodities; seasonal trends; refinery availability; planned and unplanned refinery maintenance; current and potential future environmental regulations, including regulations pertaining to the production and use of non-renewable resources; emissions, including, but not limited to carbon; market pricing and the accessibility and liquidity of these and related markets; prices and availability of alternate sources of energy; actions of domestic or foreign governments or regulatory bodies that may impact commodity prices; enforcement of government or environmental regulations; public sentiment towards the use of non- renewable resources; political stability and social conditions in countries producing these commodities; market access constraints and transportation interruptions; terrorist threats; technological developments; economic sanctions; outbreak or continuation of a pandemic, or war or other international or regional conflict and any related government action; the occurrence of natural disasters; and weather conditions.

The recent increase in focus on the timing and pace of the transition to a lower-carbon economy and resulting trends will likely affect global energy demand and usage, including the composition of the types of energy generally used by industry and individual consumers. Under certain aggressive low-carbon scenarios, potential demand erosion could contribute to commodity price fluctuations and structural commodity price declines. However, it is not currently possible to predict the timelines for, and precise effects of, the transition to a lower-carbon economy.

The financial performance of our oil sands operations could also be impacted by discounted or reduced commodity prices for our oil sands production relative to certain international benchmark prices, due, in part, to constraints on the ability to transport and sell products to domestic and international markets and the quality of oil produced. Of particular importance to us are diluent cost and supply and the price differentials between bitumen and both light to medium crude oil and heavy crude oil. Bitumen is more expensive for refineries to process and therefore generally trades at a discount to the market price for light to medium crude oil and heavy crude oil which, along with higher diluent costs, can adversely affect our financial condition.

The financial performance of our refining operations is also impacted by the relationship, or margin, between refined product prices and the prices of refinery feedstock. Refining margins are subject to seasonal factors as production levels change to match seasonal demand. Sales volumes, prices, inventory levels and inventory values will fluctuate accordingly. Future refining margins are uncertain and decreases in refining margins may have a negative impact on our business, results of operations, cash flows and financial condition.

All these factors are beyond our control and can result in a high degree of both cost and price volatility. Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars. See "Foreign Exchange Rates" below.

Fluctuations in the commodity prices, associated price differentials, and refining margins may impact our ability to meet guidance targets, the value of our assets, our cash flows, the level of shareholder returns and our ability to maintain our business and fund projects. A substantial decline in these commodity prices or an extended period of low commodity prices may result in an inability to meet all our financial obligations as they come due; a delay or cancellation of existing or future drilling, development or construction programs; curtailment in production; unutilized long-term transportation commitments; and/or low utilization levels at our refineries. Fluctuations in commodity prices, associated price differentials, and refining margins impact our financial condition, results of operations, cash flows, growth, access to capital and cost of borrowing.

The commodity price risks noted above, as well as other risks such as market access constraints and transportation restrictions, reserves replacement and reserves estimates and cost management that are more fully described herein, may have a material impact on our business, financial condition, results of operations, cash flows and reputation, and may be considered indicators of impairment. Another potential indicator of impairment is the comparison of the carrying value of our assets to our market capitalization.

As discussed in this MD&A, we conduct an assessment, at each reporting date, of the carrying value of our assets in accordance with IFRS. If crude oil, refined product, natural gas and NGL prices decline significantly and remain at low levels for an extended period, or if the costs of our development of such resources significantly increase, the carrying value of our assets may be subject to impairment and our net earnings could be adversely affected.

Risks Associated with Financial Risk Management Activities

Our Board-approved Market Risk Management Policy allows Management to use approved derivative financial instruments as needed, within authorized limits, to help mitigate the impact of changes in crude oil and condensate prices and differentials, NGL and natural gas spreads, basis and prices, electricity prices, refined product and crack spread margins, as well as fluctuations in foreign exchange rates and interest rates. We may also use derivative instruments in various operational markets to help optimize our supply costs or sales of our production, or fixed-price commitments for the purchase or sale of crude oil, natural gas, NGLs and refined products.

These risk management activities may expose us to risks which may cause significant loss. These risks include but are not limited to: changes in the valuation of the risk management instrument being poorly correlated to the change in the valuation of the underlying exposures; change in price of the underlying commodity or market value of the instrument; lack of market liquidity; insufficient counterparties to transact with; counterparty default; deficiency in systems or controls; human error; the unenforceability of contracts; and any inability to fulfill our delivery obligations related to the underlying physical transaction. These financial instruments may also limit the benefit to us if commodity prices, interest or foreign exchange rates change.

For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 3, 35 and 36 of the Consolidated Financial Statements.

Impact of Financial Risk Management Activities

Cenovus may employ various price alignment and volatility management strategies, including financial risk management contracts, to reduce volatility in future cash flows and improve cash flow stability.

Transactions typically span across periods. As such, these transactions reside across both realized and unrealized risk management. As the financial contracts settle, they will flow from unrealized to realized risk management gains and losses.

The discussion below summarizes the sensitivities of the fair value of our risk management positions to fluctuations in commodity prices and foreign exchange rates, with all other variables held constant. Management believes the price fluctuations identified below are a reasonable measure of volatility. The impact of the below on the Company's open risk management positions could have resulted in an unrealized gain (loss) impacting earnings before income tax as follows:

As at December 31, 2023	Sensitivity Range	Increase	Decrease
Power Commodity Price	± C$20.00/MWh [1] Applied to Power Hedges	**92**	**(92)**

(1) One thousand kilowatts of electricity per hour ("MWh").

A sensitivity analysis for the following fluctuating commodity prices and foreign exchange rates on the Company's open risk management positions was found to result in a nominal unrealized gain (loss) impacting earnings before income tax:

- A US$10.00 per barrel increase or decrease in the benchmark crude oil and benchmark condensate commodity price (primarily WTI).
- A US$2.50 per barrel increase or decrease in the WCS (excluding the Hardisty location) and condensate differential price.
- A US$5.00 per barrel increase or decrease in the WCS differential price.
- A US$10.00 per barrel increase or decrease in refined products commodity prices.
- A US$1.00 per one thousand cubic feet increase or decrease in the Henry Hub commodity price.
- A US$0.50 per one thousand cubic feet increase or decrease in natural gas basis prices.
- A $0.05 increase or decrease in the U.S. to Canadian dollar exchange rate.

For further information on our risk management positions, see Notes 35 and 36 of the Consolidated Financial Statements.

Credit, Liquidity and Availability of Future Financing

The future development of our business may be dependent on our ability to obtain additional capital, including, but not limited to, debt and equity financing. Among other things, unpredictable financial markets, a sustained commodity price downturn or significant unanticipated expenses, or a change in law, market fundamentals, our credit ratings, business operations or investor or lender policy or sentiment, may impede our ability to secure and maintain cost-effective financing.

Capital markets are increasingly considering ESG matters, including those related to the transition to a lower carbon economy. Our ability to access capital and secure insurance coverage, at reasonable costs, or at all, may be adversely affected in the event that stakeholders adopt more restrictive decarbonization policies, we fail to achieve our GHG emissions reduction goals, or it is perceived that our GHG emissions reduction goals are insufficient or will not be achieved.

An inability to access capital, on terms acceptable to us, or at all, could affect our ability to make future capital expenditures, to maintain desirable financial ratios and to meet our financial obligations as they come due, potentially resulting in a material adverse effect on our business, financial condition, results of operations, cash flows, ability to comply with various financial and operating covenants, credit ratings and reputation.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic, business, regulatory, market and other conditions, some of which are beyond our control. If our operating and financial results are not sufficient to service current or future indebtedness, we may take actions such as: reducing or suspending share repurchases and/or dividends; reducing or delaying business activities, investments or capital expenditures; selling assets; restructuring or refinancing our debt; or seeking additional capital that could have less favourable terms.

We are required to comply with various financial and operating covenants under our credit facility and the indentures governing our debt securities. Non-compliance with these covenants may lead to restrictions on access to capital or accelerated repayment.

Credit Ratings

Our Company and our capital structure are regularly evaluated by credit rating agencies. Credit ratings are based on our financial and operational strength and several factors not entirely within our control, including, but not limited to, conditions affecting the oil and gas industry generally, industry risks associated with the transition to a lower-carbon economy, and the general state of the economy. There can be no assurance that one or more of our credit ratings will not be downgraded or withdrawn entirely by a rating agency.

A reduction in any of our credit ratings, particularly a downgrade below investment grade ratings, or a negative change in the Company's credit ratings outlook, could adversely affect the cost and availability of borrowing, and access to sources of liquidity and capital. A failure to maintain our current credit ratings could affect our business relationships with counterparties, operating partners, and suppliers.

If one or more of our credit ratings falls below certain ratings thresholds, we may be obligated to post additional collateral in the form of cash, letters of credit or other financial instruments to establish or maintain business arrangements. Failure to provide adequate credit risk assurance to counterparties and suppliers may result in foregoing or having contractual business arrangements terminated.

Exposure to Counterparties

In the normal course of business, we enter contractual relationships with suppliers, partners, lenders, customers and other counterparties for the provision and sale of goods and services, in connection with our risk management activities, and in respect of asset or securities acquisitions and dispositions. If such counterparties do not fulfill their contractual obligations on a timely basis or at all, we may suffer financial losses or delays to our development plans, or we may have to forego other opportunities, all of which could materially impact our business, results of operations and financial condition.

Foreign Exchange Rates

Fluctuations in foreign exchange rates may affect our results, particularly the U.S./Canadian dollar and RMB/Canadian dollar exchange rates. Global prices for crude oil, refined products and natural gas are generally determined by reference to U.S. dollar benchmark prices. In addition, a significant portion of our long-term debt and interest expense is also denominated in U.S. dollars, while many of our operating and capital costs are in Canadian dollars. A portion of our long-term sales contracts in Asia Pacific are priced in RMB. A change in the value of the Canadian dollar relative to the U.S. dollar or the RMB will impact revenues and costs, as expressed in Canadian dollars. The Company periodically enters into foreign exchange transactions to manage our exposure to exchange rate fluctuations. However, the fluctuations in exchange rates are beyond our control and could have a material adverse effect on our cash flows, results of operations and financial condition.

Interest Rates

Market interest rates are impacted by actions taken by central banks to stabilize the economy and moderate inflation and have increased in response to inflation. Changes in interest rates could increase our net interest rate exposure and affect how certain liabilities are recorded, both of which could negatively impact our cash flow and financial results. We are also exposed to interest rate fluctuations upon the refinancing of maturing long-term debt and potential future financings at prevailing interest rates. We may periodically enter into transactions to manage our exposure to interest rate fluctuations.

Dividend Payments and Purchase of Securities

The payment of dividends, whether base, variable or preferred, the continuation of our dividend reinvestment plan and any potential purchase by Cenovus of our securities is at the discretion of our Board and is dependent upon, among other things, financial performance, debt covenants, satisfying solvency tests, our ability to meet financial obligations as they come due, working capital requirements, future tax obligations, future capital requirements, commodity prices and other risks identified in the Risk Management and Risk Factors section of this MD&A. Specifically, in connection with Cenovus's capital allocation framework, the Company will target returns to shareholders as a percentage of Excess Free Funds Flow, through share buybacks or variable dividends, based on Net Debt at the preceding quarter-end, as described in this MD&A. The frequency and amount of variable dividend payments, if any, may vary significantly over time as a result of our Net Debt and Excess Free Funds Flow, amount of share buybacks and other factors inherent with our capital allocation framework from time to time. Our Net Debt and Excess Free Funds Flow may vary from time to time as a result of, among other things, our business plans, results of operations, financial condition and impact of any of the risks identified in the Risk Management and Risk Factors section of this MD&A. The Company can provide no assurance that it will continue to pay base or variable dividends or authorize share buybacks at the current rate or at all as the capital allocation framework, and any share repurchases and payment of dividends thereunder, remains at the discretion of our Board and is dependent on, among other things, the factors described above. Further, the individual or aggregate amount of base or variable dividends, if any, paid by Cenovus from time to time may result in adjustments to the exercise price and the exchange basis (the number of common shares received for each Cenovus Warrant exercised) of the Cenovus Warrants under the terms of the indenture governing the Cenovus Warrants. Such adjustments may impact the value received by Cenovus upon the exercise of Cenovus Warrants and may result in additional issuances of common shares on the exercise of Cenovus Warrants which may have a further dilutive effect on the ownership interest of shareholders of Cenovus and on Cenovus's earnings per share.

Disclosure Controls and Procedures and Internal Control Over Financial Reporting ("ICFR")

Based on their inherent limitations, disclosure controls and procedures and ICFR may not prevent or detect misstatements, and even those controls determined to be effective can only provide reasonable assurance with respect to financial statement preparation and presentation. Failure to adequately prevent, detect and correct misstatements could have a material adverse effect on our business, financial condition, results of operations, cash flows and reputation.

Operational Risk

Operational Considerations (Safety, Environment and Reliability)

Our operations are subject to risks generally affecting the oil and gas, and refining industries and normally incidental to: (i) the storing, transporting, processing and marketing of crude oil, refined products, natural gas, NGLs and other related products; (ii) the drilling and completion of onshore and offshore crude oil and natural gas wells; (iii) the operation and development of crude oil and natural gas properties; (iv) the operation of refineries, terminals, pipelines and other transportation and distribution facilities in the jurisdictions in which we conduct our business, including at facilities operated by our partners or third-parties; and (v) the development and operation of projects relating to our GHG emissions reduction goals, including carbon capture utilization and storage projects. These risks include but are not limited to: the effects of government actions or regulations, policies and initiatives; encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; fires; flooding; geologic activity arising from fracking or carbon capture utilization and storage projects; explosions; blowouts; loss of containment; gaseous leaks; power outages; migration of harmful substances into water systems; releases or spills, including releases or spills from offshore operations, shipping vessels or other marine transport incidents; aviation, railcar or road transportation incidents; iceberg incidents; accidents or damage caused by third parties or otherwise occurring in the operation of our business; uncontrollable flows of crude oil, natural gas or well fluids; failure to follow operating procedures or operate within established operating parameters; adverse weather conditions; corrosion; pollution; freeze-ups and other similar events; the breakdown or failure of equipment, pipelines, facilities, wells and projects; the breakdown or failure of operational and information technology and systems and processes, any compromise thereof or released data; regular or unforeseen maintenance; the performance of equipment at levels below those originally intended; failure to maintain adequate supplies of spare parts; operator error; labour disputes; disputes with interconnected facilities and carriers; planned or unplanned operational disruptions or apportionment on third-party systems or refineries, which may prevent the full utilization of such party's facilities and pipelines; spills at truck terminals and hubs; spills associated with the loading and unloading of potentially harmful substances; loss of product; unavailability of feedstock; price and quality of feedstock; epidemics or pandemics; protests, blockades or other acts of activism; catastrophic events, including, but not limited to, war or other regional or international conflict, adverse sea conditions, vandalism or terrorism, extreme weather events, wildfires and natural disasters and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites.

Climate change may result in an increased level of operational risk requiring increased or additional mitigation measures. Systemic climatic changes or extreme climatic conditions may increase our exposure to, and magnitude of the impact of physical climate risks, such as floods, wildfires, earthquakes, hurricanes, storms, extreme temperatures and other extreme weather events or natural disasters. For example, the frequency and severity of wildfires may result in the shutting in and bringing down of our producing assets and processing plants. In addition, our Atlantic operations may be impacted by severe weather conditions, including winds, flooding and variable temperatures, which are contributing to the melting of northern ice and increased creation of icebergs. Severe weather conditions may result in an operational incident with the potential to result in spills, asset damage, and production or refining disruption. Our other operations are also subject to chronic physical risks such as a shorter timeframe for our winter drilling program, changes in the water table and reduced access to water due to drought conditions. A systemic change in temperature or precipitation patterns could result in more challenging conditions for the construction of ice roads, execution of our winter drilling program and reclamation activities and could reduce the availability of water due to the increasing likelihood of drought conditions.

If any such risks materialize, they may: interrupt operations; impair our ability to achieve our ESG targets, including our GHG emissions reduction goals; impact our reputation; cause loss of life or personal injury; result in loss of or damage to equipment, property, operational and information technology and control systems and data; cause environmental damage that may include polluting water, land or air; and may result in regulatory action, fines, penalties, civil suits or criminal or regulatory charges against us, any of which may have a material adverse effect on our business, financial condition, results of operations, cash flows and reputation.

In addition, our oil sands operations are susceptible to reduced production, slowdowns, shutdowns and restrictions on our ability to produce higher value products due to the interdependence of our component systems. Delineation of the resources, the costs associated with production, including drilling wells for SAGD operations, and the costs associated with refining oil can entail significant capital outlays. The operating costs associated with our oil sands production are largely fixed in the short-term and, as a result, operating costs per unit are largely dependent on levels of production.

We maintain a comprehensive insurance program in respect of our assets and operations. However, not all potential occurrences and disruptions in respect of our assets or operations are insured or are insurable, and we cannot guarantee that our insurance coverage will be available or sufficient to fully cover any claims that may arise from such occurrences or disruptions. The occurrence of an event that is not fully covered by our insurance program could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Market Access Constraints and Transportation Restrictions

Our production is transported through, and our refineries are reliant on, various pipelines and terminals, as well as rail, marine and truck networks, to transport feedstock and refined products to and from our facilities. Increased tariffs or disruptions in, or restricted availability of, pipeline, terminal, marine, rail or truck transport systems could limit the ability to deliver production volumes and adversely affect commodity prices, sales volumes and/or the prices received for our products, projected production growth, upstream or refining operations and cash flows. These interruptions and restrictions may be caused by, among other things, the inability of the pipeline or marine, rail or truck networks to operate, or may be related to capacity constraints if supply into the system exceeds the infrastructure capacity. There can be no certainty that third-party pipeline projects for new or expanded capacity will be constructed or that such projects would provide sufficient transportation capacity. Opposition to new and expanded pipeline projects have been influenced by, among other things, concerns about pipeline spills, GHG emissions and the transition to a lower carbon economy.

There is no certainty that rail, marine and truck transport and other alternative types of transportation for our production will be sufficient to address any gaps caused by operational constraints on the pipeline system. In addition, our rail, marine and truck shipments may be impacted by service delays, shortages of skilled labour, inclement weather, vessel, railcar or truck availability, railcar derailment, geopolitical factors, war, terrorism, or other international or regional conflict, or other rail, marine or truck transport incidents and could adversely impact sales volumes or the price received for product or impact our reputation or result in legal liability, loss of life or personal injury, loss of equipment or property or environmental damage. In addition, rail, marine and trucking regulations are constantly being reviewed to ensure the safe operation of the supply chain. Should regulations change, the costs of complying with those regulations will likely be passed on to shippers and may adversely affect our ability to transport by rail, marine or truck transport or the economics associated with such transportation. Finally, planned or unplanned shutdowns, outages or closures of our refineries or third-party systems or refineries may limit our ability to deliver product with negative implications on our business, financial condition, results of operations and cash flows.

Reserves Replacement and Reserve Estimates

If we fail to acquire, develop or find additional crude oil and natural gas reserves, our reserves and production will decline materially from their current levels. Our financial condition, results of operations and cash flows are highly dependent upon successfully producing from current reserves and acquiring, discovering or developing additional reserves. Exploring for, developing or acquiring reserves is capital intensive. To the extent our cash flow is insufficient to fund capital expenditures and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our crude oil and natural gas reserves will be impaired. In addition, we may be unable to find and develop or acquire additional reserves to replace our crude oil and natural gas production at acceptable costs.

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows and revenue derived therefrom are based on a number of variable factors and assumptions including, but not limited to: geological and engineering estimates; product prices; future operating and capital costs; historical production from the properties and the assumed effects of regulation by governmental agencies, including royalty payments and taxes, and environmental and emissions related regulations and taxes; initial production rates; production decline rates; and the availability, proximity and capacity of oil and gas gathering systems, pipelines, rail transportation and processing facilities, all of which may cause actual results to vary materially from estimated results.

All such estimates are uncertain, and classifications of reserves are only attempts to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenue expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves may vary from current estimates and such variances may be material.

Estimates with respect to reserves that may be developed and produced in the future are often based on volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Subsequent evaluation of the same reserves based on production history will result in variations, which may be material, in the estimated reserves.

The production rate of oil and gas properties tends to decline as reserves are depleted while the associated operating costs increase. Maintaining an inventory of developable projects to support future production of crude oil and natural gas depends on, among other things: obtaining and renewing rights to explore, develop and produce oil and natural gas; drilling success; completing long-lead time capital intensive projects on budget and on schedule; and the application of successful exploitation techniques on mature properties. Our business, reputation, financial condition, results of operations and cash flows are highly dependent upon successfully producing current reserves and adding additional reserves.

Cost Management and Inflation

Development, operating and construction costs are affected by a number of factors including, but not limited to: development, adoption and success of new technologies, including those related to our GHG emissions reduction goals; inflationary price pressure; changes in regulatory compliance costs; scheduling delays; interruptions to existing market access infrastructure; failure to maintain quality construction and manufacturing standards; equipment limitations, including the cost or availability of oil and gas field equipment; commodity prices; higher steam-oil ratios in our Oil Sands operations; changing government or environmental policies; regulations and supply chain disruptions, including force majeure; and access to skilled labour and critical third-party services. In addition, if our costs were to become subject to significant inflationary pressures, we may not be able to fully offset such higher costs through corresponding increases in commodity prices and other sources of funding. Continued inflation and any governmental response thereto, such as the imposition of higher interest rates or wage controls, our inability to manage costs, or our inability to secure equipment, materials, skilled labour or third-party services necessary to our business activities for the expected price, on the expected timeline, or at all, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Technology, Information Systems and Data Privacy

We rely heavily on technology, including operating technology and information technology, to effectively operate our business. This includes on premise systems (such as networks, computer hardware and software), telecommunications systems, mobile applications, cloud services and other technology systems, networks, and services, including systems using artificial intelligence. Some systems and services are provided by third parties. In the event we are unable to access, use, rely upon, secure, upgrade, and take other steps to maintain or improve the efficiency, resiliency and efficacy of such systems and services, the operation of such systems and services could be interrupted, resulting in operational interruptions or the loss, corruption or release of data.

In the ordinary course of business, we collect, use and store sensitive data, including intellectual property, proprietary information, business information, and personal information. Despite our security measures, our technology systems, infrastructure, and services may be vulnerable to attacks (such as by hackers, cyberterrorists or other third parties), disruptions from staff or third-party error, malfeasance, natural disasters, acts of state or industrial espionage, activism, terrorism, war, regional or international conflict, or the geopolitical landscape. These risks also include, but are not limited to, cyber-related fraud or attacks such as attempts to circumvent electronic communications controls, impersonating internal personnel or business partners to divert payments and financial assets to accounts controlled by the perpetrators, or introducing ransomware into one or more systems or services to extract a payment, preventing access to systems, among others.

Any such incident, breach, or disruption of our internal or our third-party service providers' technology systems or services, or other vendor technology systems and services (including where a threat actor is successful in bypassing our cyber-security measures and business process controls), could result in loss or the exposure of internal, confidential, business, financial, proprietary, personal or other sensitive information.

The rapid emergence and continuous evolution of generative artificial intelligence tools may exacerbate the Company's technology, information systems and data privacy related risks due to its potential for user misuse, biased decision-making or unauthorized exposure of Cenovus's sensitive data.

Cyber incidents, breaches or irresponsible use of technology or data, including through the irresponsible use of or reliance upon artificial intelligence tools, could result in business interruption, theft or misuse of confidential information, financial losses, remediation and recovery costs, legal claims or proceedings, liability under laws that govern data, its processing, or the decisions that may arise from same, including, laws related to data transfers, privacy and the protection of data, regulatory penalties or scrutiny, fines, operational disruption, site shut-down, leaks or other negative consequences, including damage to our reputation, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

The regulation of technology is rapidly evolving across many of the jurisdictions in which we operate, creating a complex legal and regulatory framework, including existing and proposed laws and regulations that govern data, data processing and related tools, data transfers, artificial intelligence, data protection and privacy. These laws and regulations include obligations on companies that process personal information and provide additional rights of actions and remedies to individuals whose personal information is in the Company's control.

Failure to comply with these regulatory standards, including the misuse of or failure to secure personal information, could result in violation of data protection, artificial intelligence and privacy laws and regulations, proceedings against the Company by governmental entities or others, imposition of severe fines and penalties by governmental authorities, damage to our reputation and credibility, and may have a negative impact on financial condition, results of operations and cash flows. Compliance with continuously evolving legislation may also result in increased operating costs.

Competition

The oil and gas industry is highly competitive in all aspects, including accessing capital, the exploration and development of new and existing sources of supply, the acquisition of crude oil and natural gas interests and the refining, distribution and marketing of oil and gas products. We compete with other producers, refiners and marketers, some of which may have lower operating costs or greater resources than our Company does. Competitors may develop and implement technologies which are superior to those we employ. The oil and gas industry also competes with other industries in supplying energy, fuel and related products to consumers, including renewable energy sources which may become more prevalent in the future. We may not be able to compete successfully against current and future competitors, and competitive pressures could have a material adverse effect on our business, reputation, financial condition, results of operations and cash flows.

Project Execution

We manage a variety of growth and optimization projects across our global portfolio of assets. In addition, we have a number of other projects in various stages of planning and development, including projects related to our GHG emissions reduction goals. The wide range of risks associated with project development and execution, as well as the commissioning and integration of new facilities with existing assets, can impact the economic viability of our projects. These risks include, but are not limited to: our ability to obtain the necessary environmental and regulatory approvals; our ability to obtain favourable terms or to be granted access within land-use agreements; our ability to access, implement and use operational and information technologies and data, including improvements thereto; risks relating to schedule, resources and costs, including the availability and cost of materials, equipment and qualified personnel; the impact of supply chain disruptions; the impact of general economic, business and market conditions including inflationary pressures; the impact of weather conditions; risk related to the accuracy of project cost estimates; our ability to finance capital expenditures and expenses on a cost effective basis; our ability to identify or complete strategic transactions; and the effect of changing government regulation and public expectations in relation to the impacts of oil and gas operations on the environment and associated with GHG emissions abatement initiatives. The commissioning and integration of new infrastructure and facilities within our existing asset base could cause delays in achieving performance targets and objectives. Failure to manage these risks could affect our safety and environmental record and have a material adverse effect on our financial condition, results of operations and cash flows and reputation.

Joint Ventures and Partnerships

Some of our assets are not operated or controlled by us or are held in partnership with others, including through joint ventures. In addition, certain of our projects under development, including those related to our GHG emissions reduction goals, are expected to be constructed and operated in collaboration with third parties. Therefore, our results of operations, cash flows and progress towards our GHG emissions reduction goals may be affected by the actions of third-party operators or partners in areas where our ability to control and manage risks may be reduced. We rely on the judgment and operating expertise of our partners in respect of the development and operation of such assets and to provide information on the status of such assets and related results of operations; however, we are, at times, dependent upon our partners for the successful execution and operation of various projects and assets, their management of operational issues and their reporting.

Our partners may have objectives and interests that either do not align with or may conflict with our interests. No assurance can be provided that our future demands or expectations relating to such assets and projects will be satisfactorily met in a timely manner or at all. If a dispute with a partner or partners were to occur over the development and operation of a project, or if a partner or partners were unable to fund their contractual share of the capital expenditures, a project could be delayed, and we could be partially or totally liable for our partner’s share of the project. Should one of our partners become insolvent, we may similarly be directed by applicable regulators to carry out obligations on behalf of our partner and may not be able to obtain reimbursement for these costs. Failure to manage these partner risks could have a material adverse effect on our business, financial condition, results of operations, progress towards our GHG emissions reduction goals, reputation and cash flows.

Existing and Emerging Technologies

Current technologies used for the recovery of bitumen are energy intensive, including SAGD which requires significant consumption of natural gas, in the production of steam used in the recovery process. The amount of steam required in the recovery process varies and therefore impacts costs. The performance of the reservoir affects the timing and levels of production using SAGD technology. A large increase in recovery costs could cause certain projects that rely on SAGD technology to become uneconomical, which could have a negative effect on our business, financial condition, results of operations, and cash flows. In addition, we depend on, among other things, the availability and scalability of existing and emerging technologies to meet our business goals including our ESG targets and ambitions. Limitations related to the development, adoption and success of these technologies or the development of disruptive technologies could have a negative impact on our long-term business resilience.

Governmental Policy

Shifts in government policy by existing administrations or following changes in government in jurisdictions in which we operate or elsewhere can impact our operations and ability to grow our business. Restrictions on fossil fuel-based energy use, cross-border economic activity, and development of new infrastructure can impact our opportunities for continued growth. We are committed to working with all levels of government in the jurisdictions in which we operate to ensure we remain competitive and risks are understood, and mitigation strategies are implemented; however, we cannot guarantee the outcomes of changes in government policy which may adversely affect our business, results of operations, financial condition or reputation.

Regulatory Risk

The oil and gas industry in general and our operations in particular are subject to regulation and intervention under various levels of legislation in the countries in which we operate, seek to develop or explore in matters which include, but are not limited to: land tenure; permitting of projects; royalties; taxes (including income taxes); government fees; production rates; environmental protection; protection of certain species or lands; cumulative effects and/or impacts from all types of industrial development; environmental plans and regulations; the reduction of GHG and other emissions; the export of crude oil, natural gas and other products; the transportation of crude oil, natural gas and other products by pipeline, rail, marine or truck transport; generation, handling, storage, transportation, treatment and disposal of hazardous substance; the awarding, acquisition and maintenance of exploration, development and production rights; the imposition of specific drilling obligations; control over the development, abandonment and reclamation of fields (including restrictions on production) and/or facilities; and possible expropriation or cancellation of contract rights. See “Environmental Plans and Regulations Risks” below. Any changes to applicable regulatory regimes, including the implementation of new regulations or enforcement initiatives, or the modification or changed interpretation of existing regulations, could impact our existing and planned projects requiring increased capital investment, operating expenses or compliance costs, which could adversely impact our financial condition, results of operations, cash flows and reputation.

Regulatory Approvals

Our operations require us to obtain approvals from various regulatory authorities and there are no guarantees that we will be able to obtain and maintain on acceptable conditions, or at all, all necessary licenses, permits, and other approvals required to conduct activities (including, without limitation, certain exploration, development and operating activities) related to our projects. In addition, obtaining certain approvals from regulatory authorities can involve, among other things, stakeholder consultation, Indigenous consultation, consensus seeking, collaboration or consent, environmental impact assessments and public hearings. Regulatory approvals obtained may be subject to the satisfaction of certain conditions including, but not limited to: security deposit obligations; ongoing regulatory oversight of projects; mitigating or avoiding project impacts; environmental and habitat assessments; and other commitments or obligations. The failure to obtain applicable regulatory approvals or satisfy any conditions on a timely basis or satisfactory terms could result in increased costs, project delays, and may limit Cenovus’s ability to develop or expand proposed projects efficiently or at all.

Abandonment and Reclamation

We are subject to oil and gas asset abandonment, remediation and reclamation (“A&R”) liabilities for our operations, development and exploration, including those imposed by regulation under various levels of legislation in the jurisdictions in which we conduct operations, development or exploration.

We maintain estimates of our A&R liabilities; however, it is possible that these costs may change materially before decommissioning due to regulatory changes, technological changes, ecological risks, acceleration of decommissioning timelines, and inflation, among other variables. For our Atlantic Canada offshore operations, the present value cost for the expected scope of decommissioning and abandonment of the offshore wells and facilities is estimated based on known regulations, procedures and costs today for undertaking the decommissioning, the majority of which is projected to be incurred in the late 2030s.

In Alberta, Saskatchewan and British Columbia, the A&R liability regimes include orphan well funds that are funded through a levy imposed on licensees, including Cenovus, based on the licensees' proportionate share of deemed A&R liabilities for oil and gas facilities, wells and unreclaimed sites. The regulators in these jurisdictions may seek additional funding for such liabilities from industry participants, including Cenovus.

We have an ongoing environmental monitoring program of owned and leased retail locations, and former owned or leased retail locations where we have retained environmental liability, and perform remediation where required to comply with contractual and legal obligations. The costs of such remediation may not be determinable due to the unknown timing and extent of corrective actions that may be required.

The impact on our business of any legislative, regulatory or policy decisions relating to the A&R liability regulatory regime in the jurisdictions in which we conduct operations, development or exploration cannot be reliably or accurately estimated. Any cost recovery or other measures taken by applicable regulatory bodies may impact Cenovus and could materially and adversely affect, among other things, our business, financial condition, results of operations and cash flows.

Royalty Regimes

Our cash flows may be directly affected by changes to royalty and mineral tax regimes. The governments of the jurisdictions where we have producing assets receive royalties on the production of hydrocarbons from lands in which they respectively own the mineral rights and which we produce under agreement with each respective government. Government regulation of royalties and mineral tax is subject to change for a number of reasons, including, among other things, political factors. In Canada, there are certain provincial mineral taxes payable on hydrocarbon production from lands other than Crown lands. The potential for changes in the royalty and mineral tax regimes applicable in the jurisdictions in which we operate, or changes to how existing royalty and mineral tax regimes are interpreted and applied by the applicable governments, creates uncertainty relating to the ability to accurately estimate future royalty rates or mineral taxes and could have a significant impact on our business, financial condition, results of operations and cash flows. An increase in the royalty rates or mineral taxes in jurisdictions where we have producing assets would reduce our earnings and could make, in the respective jurisdiction, future capital expenditures or existing operations uneconomic and may reduce the value of our associated assets.

Indigenous Land and Rights Claims

Opposition by Indigenous people to our Company, our operations, development or exploration, or disagreements between Indigenous communities, or between Indigenous peoples and governments, in the jurisdictions in which we conduct business may adversely impact our reputation, relationship with host governments, local communities and other Indigenous communities. Other impacts may include diversion of Management's time and resources, increased legal, regulatory and other advisory expenses, and our ability to explore, develop and continue to operate projects.

In Canada, Indigenous and/or treaty rights held by Indigenous peoples are protected under the constitution. Impacts to these Indigenous and treaty rights must be considered, in particular in areas where Cenovus operates on Crown lands. In some cases, there may be outstanding Indigenous and treaty rights claims, which may include land title claims, on lands where we operate, and such claims, if successful, could have a material adverse impact on our operations or pace of growth.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous rights or affect treaty rights and, in certain circumstances, accommodate their interests. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation the result of which may affect the way governments are required to fulfill their duty to consult. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect our ability to, or increase the timeline to, obtain or renew permits, leases, licenses and other approvals, or to meet the terms and conditions of those approvals.

In addition, the Canadian federal government and the British Columbia provincial government have passed legislation which requires such governments to take all necessary measures to implement the United Nations Declaration on the Rights of Indigenous Peoples ("UNDRIP"). The means and timelines associated with UNDRIP's implementation by government is ongoing and, in some instances, uncertain: additional processes have been and are expected to continue to be created, or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

Climate Change Related Risks

There is growing international concern regarding climate change and a significant increase in focus on the timing and pace of the transition to a lower-carbon economy. Governments, financial institutions, insurance companies, non-governmental organizations ("NGOs"), environmental and governance organizations, institutional investors, social and environmental activists, shareholders and individuals are increasingly seeking to implement, among other things, regulatory and policy changes, changes in investment patterns, and modifications in energy consumption habits and trends which, individually and collectively, are intended to or have the effect of accelerating the reduction in the global consumption of fossil fuel-based energy, the conversion of energy usage to less carbon- intensive forms and the general migration of energy usage away from fossil fuel-based forms of energy.

Climate change and its associated impacts may increase our exposure to, and magnitude of, each of the risks identified in the Risk Management and Risk Factors section of this MD&A. Overall, we are not able to estimate at this time the degree to which climate change-related regulatory, climatic conditions, and climate-related transition risks could impact our business, financial condition, and results of operations. Our business, financial condition, results of operations, cash flows, reputation, access to capital and insurance, cost of borrowing, ability to fund dividend payments and/or business plans may, in particular, without limitation, be adversely impacted as a result of climate change and its associated impacts.

Climate Change Regulations

We operate in several jurisdictions that regulate or have proposed to regulate GHG emissions, often with a view to transitioning to a lower-carbon economy. Some of these regulations are in effect, while others remain in various phases of review, discussion or implementation. Uncertainties exist relating to the timing and effects of these emerging regulations and other contemplated legislation, including how they may be harmonized, making it difficult to accurately determine the cost impacts. Additional changes to climate change legislation may adversely affect our business, financial condition, results of operations and cash flows, which cannot be reliably or accurately estimated at this time.

The Government of Canada has announced the carbon tax will increase to \$170/tonne CO2e by 2030 from the 2023 rate of \$65/tonne. The 2024 rate is \$80/tonne CO2e and took effect on January 1, 2024. To the extent a province's carbon pricing system does not meet the federal stringency requirements, the federal "backstop" regulations apply. Most of our Canadian-based large emitting facilities operate in jurisdictions where provincial carbon pricing regulations apply to industry. In British Columbia, the provincial carbon pricing system applies in full. In Alberta, Saskatchewan, and Newfoundland and Labrador, the provincial carbon pricing systems apply in part. These provincial programs are expected to continue to meet the federal stringency requirements such that the federal backstop regulations do not apply. The federal government has committed to engaging provinces, territories, and Indigenous organizations in an interim review of the federal carbon tax benchmark by 2026.

In December 2023, the Government of Canada announced plans to implement a national emissions cap-and-trade model under the Canadian Environmental Protection Act ("CEPA"). The proposal is to phase in the cap-and-trade system between 2026 and

2030 and have it apply to, among other things, all direct GHG emissions from liquified natural gas facilities and upstream oil and gas facilities, including offshore facilities, while also accounting for indirect emissions and emissions that are captured and permanently stored. It is currently proposed that the 2030 emissions cap (which will inform the number of emission allowances issued to regulated facilities) will be set at 35 percent to 38 percent below 2019 emission levels. Under the proposed regime, facilities that emit more than the allowances allocated would have some flexibility to compensate for a limited quantity of additional emissions, up to the level of the legal upper bound, which, for 2030, is proposed to be set at 20 percent to 23 percent below 2019 emission levels. The Government of Canada has committed to regularly reviewing the emissions cap trajectory, the emissions trading market, and access to compliance flexibilities in setting the allowance level and legal upper bound for the post-2030 period with a view to its long-term objective of achieving net-zero GHG emissions in the oil and gas sector by 2050. Draft regulations for the cap-and-trade system are scheduled to be released for comment in mid-2024.

The Government of Canada has also implemented regulations to reduce methane emissions from the crude oil and natural gas sector. The Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) ("Methane Regulation") are designed to achieve a 40 percent to 45 percent reduction from 2012 levels by 2025 through both requirements for fugitive equipment leaks and venting from well completion and compressors (which came into force on January 1, 2020), and restrictions on facility production venting restrictions and venting limits for pneumatic equipment (which came into force on January 1, 2023). In December 2023, the Government of Canada published draft amendments to the Methane Regulation to facilitate achieving an additional target to reduce oil and gas methane emissions by at least 75 percent below 2012 levels by 2030. The proposed regulatory amendments relate to venting, flaring, hydrocarbon gas destruction equipment and fugitive emissions, and would come into force between 2027 and 2030. Finalized amendments to the Methane Regulation are expected in late 2024.

The U.S. does not have federal legislation establishing targets for the reduction of, or setting individualized limits on, GHG emissions from our U.S. facilities. The Renewable Fuel Standard ("RFS") was created to reduce GHG emissions and risks from that program are described below. Additionally, the federal Environmental Protection Agency ("EPA") has and may continue to promulgate regulations concerning the reporting and control of GHG emissions. Since 2010, the EPA's Greenhouse Gas Reporting Program ("GHGRP") requires any facility releasing more than 25,000 tonnes of CO2e emissions per year to report those emissions on an annual basis. In addition to reporting direct CO2e emissions, the GHGRP requires refineries to estimate the CO2e emissions from the potential subsequent combustion of the refinery's products. The U.S. has a 2030 target to reduce GHG emissions by 50 percent to 52 percent from 2005 levels. It is expected that this target will be met largely through clean energy incentives introduced under the Inflation Reduction Act as opposed to regulatory measures.

Negative consequences which could arise as a result of changes to the current regulatory environment include, but are not limited to, changes in environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, potentially increasing the cost of construction, operation and abandonment. Other possible effects from emerging regulations may also include, but are not limited to: increased compliance costs; permitting delays; shift away from fossil fuel-based energy; and substantial costs to generate or purchase emission credits or allowances, all of which may increase operating expenses. Further, emission allowances or offset credits may not be available for acquisition or may not be available on an economic basis, required emissions reductions may not be technically or economically feasible to implement, in whole or in part, and failure to have access to resources or technology to meet emissions reduction requirements or other compliance mechanisms may have a material adverse effect on our business resulting in, among other things, fines, permitting delays, penalties, shutting in production and the suspension of operations.

The extent and magnitude of any adverse impacts of current or additional programs or regulations beyond reasonably foreseeable requirements cannot be reliably or accurately estimated at this time, in part because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the timeframes for compliance. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to us.

Clean Fuel Regulations

In Canada, the Clean Fuel Regulations came into force in June 2022. The aim of this regulation is to lower the GHG emissions from various liquid fossil fuels by requiring producers or importers of gasoline, diesel, kerosene, and light and heavy fuel oils ("Primary Suppliers") to lower the carbon intensity of such fuels. The regulation sets a baseline carbon intensity for each type of liquid fossil fuel, against which the Primary Suppliers must make annual carbon intensity reductions. Starting in 2022, each Primary Supplier must reduce the carbon intensity by the prescribed amount. In 2024, that amount is 90.0 gCO2e/MJ for gasoline fuels and 88.0 gCO2e/MJ for diesel fuels. These regulations could result in the negative consequences noted above under "Climate Change Regulations", including increased compliance costs, increased operating, and capital expenditures.

Low Carbon Fuel Standards

Existing and proposed environmental legislation and regulation developed by certain U.S. states, Canadian provinces and territories, the Canadian federal government and members of the European Union, regulating carbon fuel standards could result in increased compliance costs and a potential reduction in revenue. Existing and proposed regulations may negatively affect the marketing of our bitumen, crude oil or refined products (diesel and ethanol), and may require us to purchase low carbon fuel compliance credits in order to ensure compliance and support sales within such jurisdictions. These regulations have the potential to impact our business, financial condition, results of operations and cash flows.

Renewable Fuel Standards

Our U.S. refining operations are subject to various laws and regulations that impose stringent and costly requirements. The EPA has implemented the RFS program that mandates that a certain volume of renewable fuel replace or reduce the quantity of certain petroleum-based transportation fuels sold or introduced in the U.S. Obligated Parties, including refiners or importers of gasoline or diesel fuel, must achieve compliance with targets set by the EPA by blending certain types of renewable fuel into transportation fuel, or by purchasing RINs from other parties on the open market. RINs are credits used for compliance and are the “currency” of the RFS program.

Cenovus and our refinery operating partners comply with the RFS by blending renewable fuels manufactured by third parties and by purchasing RINs on the open market, where prices fluctuate. We cannot predict the future prices of RINs and renewable fuel blend stocks, and the costs to obtain the necessary RINs and blend stocks could be material. Our financial position, results of operations and cash flows may be materially impacted if we are required to pay significantly higher prices for RINs or blend stocks to comply with the RFS mandated standards.

Clean Electricity Regulations

In August 2023, the Government of Canada released draft Clean Electricity Regulations intended to accelerate progress towards a near-zero power generation sector in Canada. The draft regulations would impose a stringent performance standard on all power generation facilities on the latter of January 1, 2035 or 20 years after their commissioning date. Limited exemptions for peaking units and emergency circumstances are available under the proposed regulations, but natural gas-fired facilities will be required to convert to near-zero emissions hydrogen or install carbon capture and coal-fired units will no longer be able to legally operate. The extent of any adverse impacts of these regulations cannot be reliably or accurately estimated at this time.

Light-Duty Vehicle Greenhouse Gas Emission Standards

The U.S. EPA has mandated federal GHG emissions standards applicable to automakers by setting fuel economy standards related to passenger cars and light trucks for Model Years 2023 through 2026. The EPA’s stated intention for the rule is to prompt automakers to produce more electric vehicles and set a path to a zero-emissions transportation future. The EPA stated that it intends to initiate future rulemaking to establish multi-pollutant emissions standards for Model Year 2027 and beyond. The impact these standards may have on the future demand (and corresponding price levels) for our products is unknown and dependent upon a number of factors. In addition, the Canadian federal government has published proposed regulated sales targets for electric vehicles.

Climate Scenarios and Assumptions

We integrate the potential impact of climate change and GHG regulations and the cost of carbon at various price levels into our business planning processes. To mitigate uncertainty surrounding future emissions regulation, we evaluate our development plans under a range of carbon-constrained scenarios. We have considered the International Energy Agency (“IEA”) scenarios in our strategic planning for several years and conduct ongoing assessments of both public and private scenarios. Although Management believes that our climate-related estimates are reasonable, aligned with current, pending and potential future regulations, and informed by the IEA's climate scenarios, they are based on numerous assumptions that, if false, may have a material adverse effect on our business, financial condition and results of operations. Specifically, climate-related estimates influence our financial planning and investment decisions. Since we plan and evaluate opportunities partially on the basis of climate-related estimates, variations between actual outcomes and our expectations may have a material adverse effect on our business, financial condition, results of operations, reputation and cash flows.

Labour Relations

We depend on unionized labour for the operation of certain facilities and may be subject to employee relations and labour disputes, which could disrupt operations at such facilities. As of December 31, 2023, approximately 11 percent of our employees are represented by unions under collective bargaining agreements, which includes just over 44 percent of our U.S. workforce. At unionized worksites, there is risk that strikes or work stoppages could occur. Any strike or work stoppage (for any reason, including a health and safety shutdown) may have a material adverse effect on our business, safety, reputation, financial condition, results of operations and cash flows.

In the event of a labour dispute, strike or work stoppage, mitigation and emergency operation plans may involve significant additional expenditures to ensure continuity of operations. In addition, we may not be able to renew or renegotiate collective bargaining agreements on satisfactory terms, or at all, and a failure to do so may increase our costs. Any renegotiation of our existing collective bargaining agreements may result in terms that are less favourable to us, which may materially and adversely affect our financial condition, results of operations and cash flows.

Moreover, future unionization efforts of Cenovus's non-represented workforce or changes in legislation and regulations may result in labour shortages, higher labour costs, as well as wage, benefit, and other employment consequences, especially during critical maintenance and construction periods, all of which may have a material adverse effect on our safety and reliability performance, results of operations and cash flows and may limit our operational flexibility.

Leadership and Talent

Our success is dependent upon our Management, our leadership capabilities and the quality and competency of our workforce. If we are unable to attract and retain key personnel and critical and diverse talent with the necessary behaviors and leadership, professional and technical competencies, it could have a material adverse effect on our business, financial condition, results of operations, reputation, and our ability to meet our leadership related ESG targets.

Security and Terrorist Threats

Security threats and terrorist activities may impact our personnel, or those of partners, customers, and suppliers, which could result in injury, loss of life, extortion, hostage situations and/or kidnapping or unlawful confinement, destruction or damage to property of Cenovus or others, impact to the environment, and business interruption. A security threat or terrorist attack targeted at a facility, terminal, pipeline, rail or trucking network, office or offshore vessel/installation owned or operated by Cenovus or any of our systems, services, infrastructure, market access routes, or partnerships could result in the interruption or cessation of key elements of our operations. Outcomes of such incidents could have a material adverse effect on our business, financial condition, results of operations and cash flows.

International Developments and Geopolitical Risk

We are exposed to the financial and operational risks associated with uncertain international and regional relations. Our business includes Asia Pacific assets in the South China Sea and the Madura Strait offshore Indonesia, and includes cooperation agreements with China National Offshore Oil Corporation or its subsidiaries (collectively, "CNOOC"), which also operates certain of these assets.

Political developments impacting international trade, including trade disputes, increased tariffs and sanctions, particularly between the U.S. and China, and Canada and China, may negatively impact markets and cause weaker macroeconomic conditions or drive political or national sentiment, weakening demand for crude oil, natural gas and refined products.

We may be affected by changes to bilateral relationships, the frameworks and global norms that govern international trade and other geopolitical developments. This includes acute shocks (such as civil unrest or sanctions) and chronic stresses (such as political or business disputes and other forms of conflict, including military conflict) that may pose longer-term threats to our business. Unilateral action by, or changes in relations between, countries in which we operate, including the U.S. and China, and such countries' approaches to multilateralism and trade protectionism can impact our ability to access markets, technology, talent and capital. Disruptions or unanticipated changes of this nature may affect our ability to sell our products for optimum value or access inputs required for effective operations and have the potential to adversely affect our financial condition.

Increased tensions between the U.S. and China caused by escalated military exercises around Taiwan and the South China Sea could lead to geopolitical uncertainty in the area, which may negatively impact our China business and operations, and ultimately affect our financial condition.

Moreover, our operations may be materially adversely affected by political, economic or social instability or events, including the renegotiation or nullification of agreements and treaties, the imposition of onerous regulations, embargoes, sanctions, and fiscal policy, changes in laws governing existing operations, financial constraints, including currency restrictions and exchange rate fluctuations, unreasonable taxation and the behaviour of international public officials, joint venture partners or third-party representatives. Specifically, our Asia Pacific assets expose us to the effects of the changing U.S.-China, Canada-China and EU-China relations.

In response to foreign sanctions, China has enacted multiple blocking laws intended to diminish the effectiveness and impact of foreign trade sanctions. Specifically, China has enacted regulations granting itself the ability to unilaterally nullify the effects of certain foreign restrictions that are deemed to be unjustified to Chinese nationals and entities, which came into force on January 9, 2021. Additionally, on June 10, 2021, China enacted the Anti-Foreign Sanctions Law which grants the right to take corresponding countermeasures if a foreign country violates international law and basic norms of international relations or adopts discriminatory restrictive measures against Chinese nationals and entities and interferes in China's internal affairs. The language of the Anti-Foreign Sanctions Law is very broad, and beyond the laws themselves, little guidance has been provided regarding how the blocking laws will be enforced by the Chinese government and effectuated through the private rights of action created by these laws. The breadth and lack of specificity of such laws create additional risk and uncertainty for foreign companies operating in China, as they may result in conflicting rules and regulations in home and host countries.

Although formal export restrictions imposed against China and Chinese entities (including the placement of CNOOC on the U.S. Department of Commerce's Entity List) have not so far had a material impact on our business activities in Asia, increased export restrictions on China and Chinese entities may limit the range of certain supplies to our operations in Asia and have an adverse effect on operational efficiency, results of operations, financial condition or reputation.

It is possible that additional related actions taken by the U.S. (and its trading partners and allies), Canada, China and other nations may limit or restrict foreign companies' ability to participate in projects and operate in certain sectors of the Chinese economy, including the energy sector. The nature, extent and magnitude of the effect of dynamic trade relations cannot be accurately predicted and may have a material adverse impact on our business, prospects, financial condition, and results of operations, cash flows, and reputation.

U.S. and Canadian sanctions and trade controls related to China do not currently prevent or significantly impair our offshore operations in Asia, but they could do so in the future, particularly if U.S. sanctions and trade controls against CNOOC were to be expanded. We cannot accurately predict the implementation of U.S. or Canadian policy affecting any current or future activities by CNOOC, Cenovus's other international partners or Cenovus. Similarly, we cannot accurately predict whether U.S. restrictions will be further tightened or the impact of government action on Cenovus's offshore operations in Asia. It is possible that the U.S. or Canadian government may subject CNOOC or Cenovus's other international partners to restrictions or sanctions that may adversely impact our offshore operations in Asia.

In addition, to the extent there are business disputes or legal claims involving our business in China, there is the potential for Cenovus personnel to be subject to an entry/exit ban in China. Moreover, it is possible that, as a result of our partnership with CNOOC, we may be subject to negative media attention which may affect investors' perception of Cenovus in Canada, the U.S. and globally, and which may negatively affect our share price and reputation.

Geopolitical events, such as a shift in the relationship, an escalation or imposition of sanctions, tariffs or other trade tensions between the U.S. and China, and Canada and China, may affect the supply, demand and price of crude oil, natural gas and refined products and therefore our financial condition. The timing, extent and fallout of the ongoing tensions between the U.S. and China, as well as Canada and China, remain uncertain and the impact on our business is unknown.

Shifts in global power relations may also introduce greater uncertainty with respect to issues requiring global co-ordination (such as climate change, trade agreements, tax regulation, freedom of navigation and technology regulation), as well as raise questions on the efficacy of and trust in international institutions, including those that underpin international trade. These types of changes may cause restrictions or impose costs on our business and may inhibit our future opportunities or affect our financial condition.

Our financial condition, operations and business may be adversely affected by any of the foregoing risks associated with international relations and specifically those risks arising from evolving U.S.-China, Canada-China and EU-China relations. The nature, extent and magnitude of the effect of dynamic trade relations on us cannot be accurately predicted and may have a material adverse impact on our business, prospects, financial condition, results of operations, cash flows, and reputation.

Litigation and Claims

From time to time, we may be involved in demands, disputes, regulatory investigations or proceedings, arbitrations and/or litigation ("Claims") arising out of, or related to, our operations and other contractual relationships. Claims may be material. Due to the nature of our operations, we may be involved with various types of Claims including, but not limited to, failure to comply with applicable laws and regulations including those related to health and safety, climate change, the environment, breach of contract, negligence, product liability, antitrust, bribery and other forms of corruption, tax, securities class actions, derivative actions, patent infringement, privacy, employment, human rights, labour relations, personal injury and other claims.

In recent years there has been an increase in climate change related demands, disputes and litigation in various jurisdictions including the U.S. and Canada. While many of the climate change related actions are in preliminary stages of litigation, and in some cases assert novel or untested causes of action, there can be no assurance that legal, societal, scientific and political developments will not increase the likelihood of successful climate change related litigation against energy producers, including Cenovus. We may be subject to adverse publicity associated with such matters, which may negatively affect public perception and our reputation, regardless of whether we are ultimately found responsible.

We may be required to incur substantial expenses and devote significant resources in respect of any such Claims. In addition, any such Claims could result in unfavourable judgments, decisions, fines, sanctions, penalties, monetary damages, temporary or permanent suspensions of operations or restrictions on our business. The outcome of any such Claims can be difficult to assess or quantify and may have a material adverse effect on our business, reputation, financial condition, results of operations and cash flows.

Environmental Plans and Regulations Risks

All phases of our operations are subject to environmental regulation, oversight and enforcement pursuant to a variety of federal, provincial, territorial, state, regional and municipal laws, and regulations in the jurisdictions in which we operate (collectively, the "environmental regulations"). Land management plans may be prepared in jurisdictions in which we operate, these may be legally binding and have the same effect as regulations. Environmental plans and regulations provide that exploration areas, wells, facility sites, pipelines, refineries and other properties and practices associated with our operations be constructed, operated, maintained, abandoned, reclaimed, and undertaken in accordance with the requirements set out therein. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Land management plans may limit future resource access, and failure to comply with approved plans may result in litigation or government intervention. Third party NGOs and citizen activist groups can also directly influence environmental regulations in the jurisdictions in which we operate, including the U.S. and Canada. We anticipate that further changes in environmental legislation will occur, which may result in approval delays for critical licences and permits, stricter standards and enforcement, larger fines and liabilities, the introduction of emissions limits, increased compliance costs and increased costs for closure, controls on land and resource access, reclamation, and ecological restoration. The complexities of changes in environmental regulations make it difficult to predict the potential future impact to our business.

Compliance with environmental plans and regulations requires significant expenditures. Our future capital expenditures and operating expenses could continue to increase as a result of, among other things, developments in our business, operations, plans and objectives and changes to existing, or implementation of new, environmental regulations. Failure to comply with environmental regulations may result in, among other things, the imposition of fines, penalties, environmental protection orders, suspension of operations, legal or regulatory proceedings, and could adversely affect our reputation. The costs of complying with environmental plans and regulations and remedying noncompliance issues may have a material adverse effect on our business, financial condition, results of operations and cash flows. The implementation of new environmental regulations or changes in interpretation or the modification of existing environmental regulations affecting the crude oil, natural gas, NGL and refining industry generally could reduce demand for our products as well as shift hydrocarbon demand toward relatively lower-carbon sources and affect our long-term prospects.

U.S. environmental regulations and aggressive enforcement from regulators present challenges and risks to our U.S. operations. New emission standards, more stringent water quality standards, and regulation of emerging contaminants such as Per- and Polyfluoroalkyl Substances ("PFAS") can increase compliance costs, require capital projects, lengthen project implementation times, and have an adverse effect on our business, financial condition, results of operations and cash flows. U.S. regulators have proposed that certain PFAS be characterized as a regulatory defined hazardous waste, which could lead to additional cleanup liability at U.S. sites. See "Water Regulation" below.

Canadian Species at Risk Act

The Canadian federal Species at Risk Act and associated agreements, as well as provincial regulation regarding threatened or endangered species and their habitat, may limit the pace and the amount of development or activity in areas identified as critical habitat for species of concern, such as woodland caribou. Previous petitions and litigation against the federal government in relation to the obligations under the Species at Risk Act have raised issues associated with the protection of species at risk and their critical habitat, both federally and on a provincial level, and these petitions compelled governments to enter into binding conservation and recovery agreements. If plans and actions undertaken by the provinces are deemed insufficient to support caribou recovery, the federal legislation includes the ability to implement measures that would preclude further development or modification of existing operations. The extent and magnitude of any potential adverse impacts of legislation on project development and operations cannot be estimated, as uncertainty exists as to whether plans and actions undertaken by the provinces will be sufficient to support caribou recovery.

Canadian Federal Air Quality Management System

The Multi Sector Air Pollutants Regulations ("MSAPR"), issued under the Canadian Environmental Protection Act, 1999, seek to protect the environment and health of Canadians by setting mandatory, nationally consistent air pollutant emission standards. The MSAPR are aimed at equipment-specific Base-Level Industrial Emissions Requirements ("BLIERs"). Nitrogen oxide BLIERs from our non-utility boilers, heaters and stationary engines are regulated in accordance with specified performance standards. We anticipate that the MSAPR will result in adverse impacts to Cenovus including, but not limited to, capital investment required to retrofit existing equipment and increased operating costs.

Canadian Ambient Air Quality Standards ("CAAQS") for nitrogen dioxide, sulphur dioxide, fine particulate matter and ozone were introduced as part of a national Air Quality Management System. Provinces may implement the CAAQS at the regional air zone level and air zone management actions may include more stringent emissions standards applicable to industrial sources from approval holders in regions where we operate that may result in adverse impacts including, but not limited to, capital investment related to retrofitting existing facilities and increased operating costs.

Review of Environmental and Regulatory Processes

Increased or evolving environmental assessment obligations imposed by various levels of governments in the jurisdictions in which we operate, seek development or explore may create risk of increased costs and project development delays. The regulatory frameworks within the jurisdictions where we operate are constantly evolving and may become more onerous or costly which may impede our ability to economically develop our resources. The extent and magnitude of any adverse impacts of changes to such regulatory frameworks on project development and operations cannot be estimated at this time.

Water Regulation

We utilize fresh water in certain operations, which is obtained in accordance with respective jurisdictions' regulations, including through water licences. If water use fees increase, the terms of water licences change or there are restrictions in the amount of water available for our use, production could decline or operating expenses could increase, both of which may have a material adverse effect on our business and financial condition. There can be no assurance that the licences to withdraw water will not be rescinded or that additional conditions will not be added to licences. There is no assurance that if we require new licences or amendments to existing licences, that these licences or amendments will be granted, or granted on favourable terms. This may adversely affect our business, including the ability to operate our assets and execute development plans.

Our U.S. refineries are subject to water discharge requirements that necessitate treatment of wastewater prior to discharging. Permits for discharging water are renewed from time to time to incorporate new water quality standards and may require modifications and expansion of water treatment facilities at the sites. Pollutants such as selenium, total dissolved solids, arsenic, mercury, and others may require advanced wastewater treatment, and discharge levels will depend on the types of crude processed at our refineries. Non-compliance with permit limits can lead to enforcement actions by regulators including issuance of fines, orders to upgrade treatment plants, and suspension of operations. Federal and state regulators in the U.S. are currently addressing the emerging pollutant PFAS in water discharge permits by requiring installation of additional wastewater treatment units and requiring monitoring of PFAS in discharges.

Hydraulic Fracturing

Legislative and regulatory initiatives have been introduced related to stakeholder claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources, and are increasing the frequency of seismic activity. New laws, regulations or permitting requirements regarding hydraulic fracturing may lead to limitations or restrictions to oil and gas development activities, operational delays, increased compliance costs, restrictions to freshwater usage, additional operating requirements or increased third-party or governmental claims, resulting in increased cost of doing business as well as impacting the amount of natural gas and oil that we are ultimately able to produce from our reserves.

Cenovus ESG Focus Areas, Targets and Ambitions

We have set ambitious, achievable targets for each of our five ESG focus areas, including reducing our absolute emissions, decreasing freshwater intensity, reclaiming more land, supporting Indigenous reconciliation and increasing the number of women in leadership positions. To achieve these goals and to respond to changing market demand, we may incur additional costs and invest in new technologies and innovation. It is possible that the benefits of these investments may be less than we expect, which may have an adverse effect on our business, financial condition and reputation.

Generally, our ESG targets and ambitions depend significantly on our ability to execute our current business strategy, which can be impacted by the numerous risks and uncertainties associated with our business and the industry in which we operate, as outlined in the Risk Management and Risk Factors section of this MD&A. Investors and stakeholders increasingly compare companies based on ESG-related performance, including climate-related performance. Failure to achieve our ESG targets and ambitions, or a perception among key stakeholders that our ESG targets and ambitions are insufficient or unattainable, could adversely affect our reputation and our ability to attract capital and insurance coverage.

There is also a risk that some or all of the expected benefits and opportunities of achieving the various ESG targets and ambitions may fail to materialize, may cost more to achieve than we expect or may not occur within the anticipated time periods. In addition, there is a risk that the actions we take in implementing targets and ambitions relating to our ESG focus areas may, among other things, increase our capital expenditures and thereby impair our ability to invest in other aspects of our business, which could have a negative impact on our future operating and financial results.

Climate and GHG Emissions Reduction Goals

Our ability to meet our GHG emissions reduction goals is subject to numerous risks and uncertainties and our actions taken in implementing such goals may also expose us to certain additional and/or heightened financial and operational risks. Furthermore, our long-term ambition of reaching net zero emissions by 2050 is inherently less certain due to the longer timeframe and certain factors outside of our control, including the commercial application of future technologies that may be necessary for us to achieve this long-term ambition, and the cooperation and actions of third parties, including Pathways Alliance. The Pathways Alliance's proposed CCS project is of particular importance, and if this project is delayed or does not proceed, Cenovus's ability to achieve its GHG reduction goals and ambitions will be delayed and may not be achieved.

A reduction in GHG emissions relies on, among other things, our ability to develop, access and implement commercially viable and scalable emission reduction strategies and related technology and products. There are risks associated with relying largely or partly on new technologies, the incorporation of such technologies into new or existing operations and acceptance of new technologies in the market. If we are unable to effectively deploy the necessary technology, or such strategies or technologies do not perform as expected, we may be unable to meet our GHG emissions reduction goals on the planned timelines, or at all. In addition, there are other operational risks that may hinder our ability to successfully meet our GHG emissions reduction goals, including: unexpected impediments to, or effects of, the implementation of methane abatement and electrification initiatives in our Conventional and Conventional Heavy Oil segments; the purchase of renewable electricity; the unavailability of, or limited benefits from, technology that is expected to be commercially viable in the near term and its associated future benefits, including SAGD enhancement technologies, such as solvent-aided process and solvent-driven process technologies, carbon capture, utilization and storage technology and downhole technology improvements; a failure to capture the anticipated benefits of continued technological development; and industry collaboration and innovation to find solutions to reduce costs and GHG emissions. If we are unable to implement these strategies and technologies as planned without negatively impacting our expected operations or cost structure, or such strategies or technologies do not perform as expected, we may be unable to meet our GHG emissions reduction goals on the planned timelines, or at all.

In addition, achieving our GHG emissions reduction goals relies on the existence of a favorable and stable regulatory framework that includes, among other things, support from various levels of government, including financial support and shared capital cost commitments, which may not develop in a manner consistent with our expectations, or at all. Achieving our 2035 GHG emissions reduction goals will also require capital expenditures and Company resources, with the potential that actual costs may differ from our original estimates and the differences may be material. Furthermore, the cost of investing in emissions-reduction technologies, and the resulting change in the deployment of resources and focus, could have a negative impact on our business, financial condition, results of operations and cash flows.

Water Stewardship Targets

Our ability to meet our water stewardship targets will depend on the commercial viability and scalability of relevant water reduction strategies and related steam and water usage technology and products. There are risks associated with relying largely or partly on new technologies, the incorporation of such technologies into new or existing operations and acceptance of new technologies in the market. In the event we are unable to effectively deploy the necessary technologies, or such strategies or technologies do not perform as expected, achieving our stated target of reducing our freshwater intensity could be interrupted, delayed or abandoned.

Biodiversity Targets

Our ability to meet our biodiversity targets is subject to various operational, environmental and regulatory risks, which could impose significant costs, restrictions, liabilities and obligations on us. See “Abandonment and Reclamation” above. In addition, an increase in operating costs, changes to market conditions and access to additional capital, if needed, could result in our inability to fund, and ultimately meet, our biodiversity targets on the current timelines, or at all.

Indigenous Reconciliation Targets

A failure or delay in: (i) achieving our Indigenous reconciliation targets; or (ii) continuing to advance Indigenous reconciliation initiatives once targets have been met, may adversely affect our relationship with neighboring Indigenous businesses and communities, and our reputation. If we are unable to maintain a positive relationship with Indigenous communities near our operations, our progress and ability to develop and operate projects in line with our current business and operational strategies may be adversely impacted.

Inclusion and Diversity Targets

A failure or delay in achieving our inclusion and diversity targets and our ability to maintain targets once met, could have a material adverse effect on our recruitment activities and reputation with our stakeholders.

Reputation Risk

We rely on our reputation to build and maintain positive relationships with investors and other stakeholders, to recruit and retain staff and to be a credible, trusted company. Any actions we take that influence public or key stakeholder opinions have the potential to impact our reputation, which may adversely affect our share price, development plans and ability to continue operations.

Development of fossil fuel-based energy, and in particular the Alberta oil sands, has received considerable attention on the subjects of environmental impact, climate change, GHG emissions and Indigenous reconciliation. Concerns about oil sands may, directly or indirectly, impair the profitability of our current oil sands projects and the viability of future oil sands projects, by creating significant regulatory, economic and operating uncertainty. Increased public opposition to, and stigmatization of, the oil and gas sector, and in particular the oil sands industry, could lead to constrained access to insurance, liquidity and capital and changes in demand for our products, which may adversely impact our business, financial condition or results of operations.

Shareholder activism has been increasing in the oil and gas industry, and investors may from time-to-time attempt to effect changes to our business, governance, or reporting practices with respect to climate change or otherwise, whether by shareholder proposals, public campaigns, proxy solicitations or otherwise. Such actions could adversely impact our business by distracting our Board, Management and employees from core business operations, requiring us to incur increased advisory fees and related costs, interfering with our ability to successfully execute on strategic transactions and plans and provoking perceived uncertainty about the future direction of our business. In the event such activist shareholders are successful, Cenovus may be required to incur costs and dedicate time to adopting new practices. Such perceived uncertainty may, in turn, make it more difficult to retain employees and could result in significant fluctuation in the market price of our securities.

Other Risks

Dilutive Effect

We are authorized to issue, among other classes of shares, an unlimited number of common shares for consideration and on terms and conditions as established by our Board without the approval of our shareholders in certain instances. Any future issuances of Cenovus common shares or other securities exercisable or convertible into, or exchangeable for, Cenovus common shares may result in dilution to present and prospective Cenovus shareholders. The issuance of additional Cenovus common shares upon exercise, from time to time, of securities convertible into Cenovus common shares, including equity awards granted to our directors and officers, will have a further dilutive effect on the ownership interest of shareholders of Cenovus. Such issuances will have a dilutive effect on Cenovus's earnings per share, which could adversely affect the market price of Cenovus common shares and may adversely impact the value of our shareholders' investments.

Risks Relating to Acquisitions and Dispositions

We have completed, and may complete in the future, one or more acquisitions or dispositions for various strategic reasons. We may not be able to complete these transactions on favorable terms, on a timely basis, or at all. The integration of acquired assets and operations may result in the disruption of business, and may divert Management's focus and resources from other strategic opportunities and operational matters during the process, which may result in increased costs and adversely affect our ability to achieve the anticipated benefits of such acquisitions. Acquiring assets requires assessments of their characteristics which are inexact and inherently uncertain and, as such, the acquired assets may not produce or operate as expected, may not have the anticipated benefits or synergies and may be subject to increased costs and liabilities. Further, we may not be able to obtain or realize upon contractual indemnities from a seller for liabilities created prior to an acquisition.

Various factors could materially affect our ability to dispose of assets in the future and may also reduce the proceeds or value realized from such dispositions. We may also retain certain liabilities or agree to indemnification obligations in a sale transaction, which may be difficult to quantify at the time of the transaction and could ultimately be material. Should any of the risks associated with acquisitions or dispositions materialize, they could have an adverse effect on our business, financial condition or reputation.

Risks Related to Significant Shareholders of Cenovus

The sale into the market of Cenovus common shares held by significant shareholders of Cenovus, Hutchison Whampoa Europe Investments S.à r.l. ("Hutchison") and L.F. Investments S.à r.l. ("L.F. Investments"), or market perception regarding any intention of Hutchison or L.F. Investments to sell Cenovus common shares, could adversely affect market prices for our common shares. While Hutchison and L.F. Investments are each subject to certain voting covenants pursuant to the terms of a standstill agreement they each entered into with Cenovus, each of Hutchison and L.F. Investments may be able to impact certain matters requiring Cenovus shareholder approval.

Market for Cenovus Warrants

There can be no assurance that an active public market for Cenovus Warrants will be sustained. If such a market is sustained, the market price of the Cenovus Warrants may be adversely affected by similar factors as those impacting the market price of Cenovus common shares. In addition, the market price of Cenovus common shares will significantly affect the market price of Cenovus Warrants which may result in significant volatility in the market price of the Cenovus Warrants and may negatively impact the value of the Cenovus Warrants.

Tax Laws

Income tax laws and regulations and other laws and government incentive programs (such as Canadian Carbon Capture Utilization and Storage Investment Tax Credits) may in the future be changed or interpreted in a manner that adversely affects us, our financial results, our ability to achieve our GHG emissions reduction goals and our shareholders. Tax authorities having jurisdiction over Cenovus may disagree with the manner in which we calculate our tax liabilities such that its provision for income taxes may not be sufficient, or such authorities could change their administrative practices to Cenovus's detriment or to the detriment of our shareholders. Further, as there are usually a number of tax matters under review, income taxes are subject to measurement uncertainty. In addition, all of our tax filings are subject to audit by tax authorities who may disagree with such filings in a manner that adversely affects Cenovus and our shareholders.

The international tax environment continues to change as a result of tax policy initiatives and reforms under consideration related to the Base Erosion and Profit Shifting ("BEPS") project of the OECD. Although the timing and methods of implementation vary, numerous countries including Canada have responded to the BEPS project by implementing, or proposing to implement, changes to tax laws and tax treaties at a rapid pace. These changes may increase our cost of tax compliance and affect our business, financial condition and results of operations in a manner that is difficult to quantify. We will continue to monitor and assess potential adverse impacts on our global tax situation as a result of the BEPS project.

Pandemic Risk

Pandemics, epidemics or outbreaks, including COVID-19, remain a risk for the Company, and the ultimate impact of a pandemic is highly uncertain and subject to change. A pandemic and the corresponding measures we take to protect the health and safety of our staff and the continuity of our business may result in new legal challenges and disputes, including, but not limited to, litigation involving contract parties or employees and class action claims. Actions taken by various levels of government and health authorities in the event of a pandemic, epidemic or outbreak may result in a reduction in the demand for, and prices of, commodities that are closely linked to our financial performance and may negatively impact our business, results of operations and financial condition.

Modern Slavery Act

On January 1, 2024, the Fighting Against Forced Labour and Child Labour in Supply Chains Act ("Modern Slavery Act")came into force in Canada. The Modern Slavery Act obligates Cenovus to publish an annual modern slavery report detailing steps regarding the previous year's efforts to mitigate the risk of forced labour used at any step in their supply chain, including production of goods in Canada or elsewhere or of goods imported into Canada. There is a risk that our supply chain may actually use or be alleged to have used forced labour or child labour, and there may be difficulty in gathering sufficient information from suppliers. Additional work is required to assess and understand this risk. Such measures may affect our operational efficiency, results of operations, financial condition, or reputation.

A discussion of additional risks, should they arise after the date of this MD&A, which may impact our business, prospects, financial condition, results of operations and cash flows, and in some cases our reputation, can be found in our subsequently filed MD&A, available on SEDAR+ at sedarplus.ca, on EDGAR at sec.gov and at cenovus.com.

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.

Critical Judgments in Applying Accounting Policies

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 the Company's Consolidated Financial Statements.

Joint Arrangements

The classification of a joint arrangement that is held in a separate vehicle as either a joint operation or a joint venture requires judgment.

Cenovus has a 50 percent interest in WRB Refining LP ("WRB"), a jointly controlled entity. The joint arrangement meets the definition of a joint operation under IFRS 11, *"Joint Arrangements"* ("IFRS 11"); therefore, the Company's share of the assets, liabilities, revenues and expenses are recorded in the Consolidated Financial Statements.

Prior to February 28, 2023, Cenovus held a 50 percent interest in BP-Husky Refining LLC, which was jointly controlled with bp and met the definition of a joint operation under IFRS 11. As such, Cenovus recognized its share of the assets, liabilities, revenues and expenses in its consolidated results. Subsequent to February 28, 2023, Cenovus controls the Toledo Refinery through Ohio Refining Company LLC, as defined under IFRS 10, *"Consolidated Financial Statements"* ("IFRS 10"), and, accordingly, the Ohio Refining Company LLC was consolidated.

Prior to August 31, 2022, Cenovus held a 50 percent interest in SOSP, which was jointly controlled with BP Canada Energy Group ULC ("bp Canada") and met the definition of a joint operation under IFRS 11. As such, Cenovus recognized its share of the assets, liabilities, revenues and expenses in its consolidated results. Subsequent to August 31, 2022, Cenovus controls SOSP, as defined under IFRS 10, and, accordingly, SOSP was consolidated.

In determining the classification of its joint arrangements under IFRS 11, the Company considered the following:

- The original intention of the joint arrangements was to form an integrated North American heavy oil business. Partnerships are “flow-through” entities.
- The agreements require the partners to make contributions if funds are insufficient to meet the obligations or liabilities of the corporation and partnerships. The past development of Toledo and SOSP, and the past and future development of WRB, is dependent on funding from the partners by way of capital contribution commitments, notes payable and loans.
- WRB has third-party debt facilities to cover short-term working capital requirements. SOSP had a third-party debt facility.
- Phillips 66, as operator of WRB, either directly or through wholly-owned subsidiaries, provides marketing services, purchases necessary feedstock, and arranges for transportation and storage, on the partners' behalf as the agreements prohibit the partners from undertaking these roles themselves. In addition, the joint arrangement does not have employees and, as such, is not capable of performing these roles.
- As the operator of Toledo until February 28, 2023, bp, either directly or through wholly-owned subsidiaries, purchased necessary feedstock, and arranged for transportation and storage, on the partners' behalf. SOSP was operated like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants in accordance with the partnership agreement.
- In each arrangement, output is taken by the partners, indicating that the partners have the rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

Exploration and Evaluation Assets

The application of the Company’s accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating expenses, as well as estimated reserves and resources are considered. In addition, Management uses judgment to determine when E&E assets are reclassified to PP&E. In making this determination, various factors are considered, including the existence of reserves, and whether the appropriate approvals have been received from regulatory bodies and the Company’s internal approval process.

Identification of Cash-Generating Units

CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretation. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure, and the manner in which Management monitors and makes decisions about its operations. The recoverability of the Company’s upstream, refining, crude-by-rail, railcars, storage tanks and corporate assets are assessed at the CGU level. As such, the determination of a CGU could have a significant impact on impairment losses and impairment reversals.

Assessment of Impairment Indicators or Impairment Reversals

PP&E, E&E assets and ROU assets are reviewed separately for indicators of impairment on a quarterly basis or when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. The identification of indicators of impairment or reversal of impairment requires significant judgment.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised.

The evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels could change assumptions used to determine the recoverable amount of the Company’s PP&E and E&E assets and could affect the carrying value of those assets, may affect future development or viability of exploration prospects, may curtail the expected useful lives of oil and gas assets thereby accelerating depreciation charges and may accelerate decommissioning obligations increasing the present value of the associated provisions. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain. Environmental considerations are built into estimates through the use of key assumptions used to estimate fair value including forward commodity prices, forward crack spreads and discount rates. The energy transition could impact the future prices of commodities. Pricing assumptions used in the determination of recoverable amounts incorporate market expectations and the evolving worldwide demand for energy.

Changes to assumptions could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that, if changed, could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Crude Oil and Natural Gas Reserves

There are a number of inherent uncertainties associated with estimating crude oil and natural gas reserves. Reserves estimates are dependent upon variables including the expected future production volumes, future development and operating expenses, forward commodity prices, estimated royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test recoverable amount and DD&A expense of the Company's crude oil and natural gas assets in the Oil Sands, Conventional and Offshore segments. The Company's reserves are evaluated annually and reported to the Company by its IQREs.

Recoverable Amounts

Determining the recoverable amount of a CGU or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. For the Company's upstream assets, these estimates include quantity of reserves, expected production volumes, future development and operating expenses, forward commodity prices and discount rates. Recoverable amounts for the Company's downstream assets use assumptions such as refined product production, forward crude oil prices, forward crack spreads, future operating expenses and capital expenditures and discount rates. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of the Company's upstream assets, refining assets and crude-by-rail terminal at the end of their economic lives. Management uses judgment to assess the existence of liabilities and estimate the future value. The actual cost of decommissioning and restoration is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit-adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

Fair Value of Assets Acquired and Liabilities Assumed in a Business Combination

The fair value of assets acquired, liabilities assumed and assets given up in a business combination, including contingent consideration and goodwill, is estimated based on information available at the date of acquisition. Various valuation techniques are applied for measuring fair value including market comparable transactions and discounted cash flows. For the Company's upstream assets, key assumptions in the discounted cash flow models used to estimate fair value include forward commodity prices, expected production volumes, quantity of reserves, discount rates, future development and operating expenses. Estimated production volumes and quantity of reserves for acquired oil and gas properties were developed by internal geology and engineering professionals and IQREs. For downstream assets, key assumptions used to estimate fair value include refined product production, forward crude oil prices, forward crack spreads, discount rates, operating expenses and future capital expenditures. Changes in these variables could significantly impact the carrying value of the net assets acquired.

Income Tax Provisions

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. There are usually a number of tax matters under review; therefore, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recorded to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. There are some transactions for which the ultimate tax determination is uncertain. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods.

New Accounting Standards and Interpretations Not Yet Adopted

There are new accounting standards, amendments to accounting standards and interpretations that are effective for annual periods beginning on or after January 1, 2024, and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2023. These standards and interpretations are not expected to have a material impact on the Company's Consolidated Financial Statements or the Company's business.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, assessed the design and effectiveness of ICFR and disclosure controls and procedures ("DC&P") as at December 31, 2023. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of ICFR. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2023.

The effectiveness of our ICFR was audited as at December 31, 2023 by PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, as stated in their Report of Independent Registered Public Accounting Firm, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2023.

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

ADVISORY

Oil and Gas Information

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

Forward-looking Information

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

This forward-looking information is identified by words such as "aim", "anticipate", "believe", "capacity", "commit", "continue", "could", "estimate", "expect", "focus", "forecast", "may", "objective", "opportunities", "plan", "position", "prioritize", "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; reducing operating, capital and general and administrative costs; realizing the full value of our integrated business; supporting long term value for Cenovus; safety performance; downstream reliability and profitability; cost leadership; advocating for our company and industry; executing major projects such as West White Rose, SeaRose ALE, Narrows Lake tie-back at Christina Lake, and Foster Creek Optimization on time and on budget; delivering first oil from the West White Rose project in 2026; being best in class operators; meeting targets for our five ESG focus areas; the Pathways Alliance foundational project; sustainability and sustainability leadership; maximizing long term profitability of our assets; our 2024 capital investment budget; returning incremental value to shareholders through share buybacks and/or variable dividends in accordance with the capital allocation framework; GHG emissions; infrastructure; operating and capital costs; capital investment, allocation, and structure; capital discipline; Free Funds Flow generation; resiliency; Excess Free Funds Flow allocation; flexibility in both high and low commodity price environments; funding near-term cash requirements; managing capital structure; dividends of any kind; share repurchases under the NCIB; deleveraging; meeting payment obligations; maintaining credit ratings; debt levels; Net Debt; Net Debt to Adjusted Funds Flow Ratio; Net Debt to Adjusted EBITDA Ratio; maintaining liquidity; production and production rates; crude throughput; consistent and reliable operations at all operated assets; operating performance; liabilities from legal proceedings; cash flow; price alignment and volatility management strategies; financial results; variable payments; provision for income taxes; capturing value; mitigating the impact of crude oil and refined product differentials; integrating the Toledo and Lima refineries; optimizing run rates at the Company's refineries achieving full operation of the Superior Refinery; 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

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	Bcf	billion cubic feet	MMBOE	million barrels of oil equivalent
				CO2e	carbon dioxide equivalent
				DD&A	depreciation, depletion and amortization
				GHG	greenhouse gas
				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

Scope 1 emissions are direct GHG emissions from owned or operated facilities by the reporting company. This includes emissions from fuel combustion, venting, flaring, industrial processes and fugitive leaks from equipment.

Scope 2 emissions are indirect GHG emissions associated with the purchase or acquisition of electricity, steam, heat or cooling for use at the owned or operated facility.

Cenovus accounts for emissions on a gross operatorship basis. The Company also reports its net-equity share of emissions from all of its assets.

SPECIFIED FINANCIAL MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS including Operating Margin, Operating Margin for the Upstream or Downstream operations, Operating Margin by asset, Adjusted Funds Flow, Adjusted Funds Flow Per Share – Basic, Adjusted Funds Flow Per Share – Diluted, Free Funds Flow, Excess Free Funds Flow, Gross Margin, Refining Margin, Unit Operating Expense, Per Unit DD&A and Netbacks (including the total netbacks per BOE).

These measures may not be comparable to similar measures presented by other issuers. These measures are described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation, if applicable, of each specified financial measure is presented in this Advisory and may also be presented in the Operating and Financial Results or Liquidity and Capital Resources sections of this MD&A. Refer to the Specified Financial Measures Advisory of our 2022 annual MD&A for reconciliations of Operating Margin, Adjusted Funds Flow, Free Funds Flow, Excess Free Funds Flow for quarters in 2022 and 2021 not found below.

Operating Margin

Operating Margin and Operating Margin by asset are non-GAAP financial measures, and Operating Margin for 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.

	2023	2022	2021	**2023**	2022	2021	**2023**	2022	2021
($ millions)	**Upstream (1)**			**Downstream (1)**			**Total**		
Revenues									
Gross Sales (2)	**31,082**	41,142	27,925	**32,626**	38,010	26,258	**63,708**	79,152	54,183
Less: Royalties	**3,270**	4,868	2,454	**—**	—	—	**3,270**	4,868	2,454
	27,812	36,274	25,471	**32,626**	38,010	26,258	**60,438**	74,284	51,729
Expenses									
Purchased Product (2)	**3,152**	6,741	4,059	**28,273**	32,409	23,111	**31,425**	39,150	27,170
Transportation and Blending (2)	**11,088**	12,301	8,795	**—**	—	—	**11,088**	12,301	8,795
Operating	**3,690**	3,789	3,241	**3,201**	3,050	2,258	**6,891**	6,839	5,499
Realized (Gain) Loss on Risk Management	**12**	1,619	788	**—**	112	104	**12**	1,731	892
Operating Margin	**9,870**	11,824	8,588	**1,152**	2,439	785	**11,022**	14,263	9,373

	2023											
	Upstream (1)				**Downstream (1)**				**Total**			
($ millions)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenues												
Gross Sales (2)	**7,797**	8,783	7,285	7,217	**8,404**	9,658	7,427	7,137	**16,201**	18,441	14,712	14,354
Less: Royalties	**902**	1,135	637	596	**—**	—	—	—	**902**	1,135	637	596
	6,895	7,648	6,648	6,621	**8,404**	9,658	7,427	7,137	**15,299**	17,306	14,075	13,758
Expenses												
Purchased Product (2)	**663**	900	751	838	**7,888**	7,947	6,447	5,991	**8,551**	8,847	7,198	6,829
Transportation and Blending (2)	**2,894**	2,397	2,770	3,027	**—**	—	—	—	**2,894**	2,397	2,770	3,027
Operating	**864**	914	883	1,029	**826**	778	843	754	**1,690**	1,692	1,726	1,783
Realized (Gain) Loss on Risk Management	**19**	(10)	(13)	16	**(6)**	11	(6)	1	**13**	1	(19)	17
Operating Margin	**2,455**	3,447	2,257	1,711	**(304)**	922	143	391	**2,151**	4,369	2,400	2,102

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Comparative periods prior to the third quarter of 2023 reflect certain revisions. See Note 39 of the Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

	2022											
	Upstream [1]				Downstream [1]				Total			
($ millions)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenues												
Gross Sales [2]	8,251	10,250	11,719	10,922	8,302	10,873	10,719	8,116	16,553	21,123	22,438	19,038
Less: Royalties	875	1,226	1,582	1,185	—	—	—	—	875	1,226	1,582	1,185
	7,376	9,024	10,137	9,737	8,302	10,873	10,719	8,116	15,678	19,897	20,856	17,853
Expenses												
Purchased Product [2]	1,079	2,383	1,461	1,818	6,993	9,680	8,919	6,817	8,072	12,063	10,380	8,635
Transportation and Blending [2]	2,984	2,826	3,272	3,219	—	—	—	—	2,984	2,826	3,272	3,219
Operating	955	915	1,010	909	759	780	866	645	1,714	1,695	1,876	1,554
Realized (Gain) Loss on Risk Management	134	51	563	871	(8)	(77)	87	110	126	(26)	650	981
Operating Margin	2,224	2,849	3,831	2,920	558	490	847	544	2,782	3,339	4,678	3,464

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Comparative periods prior to the third quarter of 2023 reflect certain revisions. See Note 39 of the Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Operating Margin by Asset

	Year Ended December 31, 2023		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore [1]**
Revenues			
Gross Sales	**400**	**1,217**	**1,617**
Less: Royalties	**15**	**84**	**99**
	385	**1,133**	**1,518**
Expenses			
Transportation and Blending	**16**	**—**	**16**
Operating	**262**	**122**	**384**
Operating Margin	**107**	**1,011**	**1,118**

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

	Year Ended December 31, 2022		
($ millions)	Atlantic	Asia Pacific	Offshore [1]
Revenues			
Gross Sales	578	1,442	2,020
Less: Royalties	(3)	80	77
	581	1,362	1,943
Expenses			
Transportation and Blending	15	—	15
Operating	204	114	318
Operating Margin	362	1,248	1,610

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

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

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

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

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

	Three Months Ended December 31,		Year Ended December 31,	
($ millions)	**2023**	2022	**2023**	2022
Cash From (Used in) Operating Activities	**2,946**	2,970	**7,388**	11,403
(Add) Deduct:				
Settlement of Decommissioning Liabilities	**(65)**	(49)	**(222)**	(150)
Net Change in Non-Cash Working Capital	**949**	673	**(1,193)**	575
Adjusted Funds Flow	**2,062**	2,346	**8,803**	10,978
Capital Investment	**1,170**	1,274	**4,298**	3,708
Free Funds Flow	**892**	1,072	**4,505**	7,270
Add (Deduct):				
Base Dividends Paid on Common Shares	**(261)**	(201)		
Dividends Paid on Preferred Shares	**(9)**	—		
Settlement of Decommissioning Liabilities	**(65)**	(49)		
Principal Repayment of Leases	**(72)**	(74)		
Acquisitions, Net of Cash Acquired	**(14)**	(7)		
Proceeds From Divestitures	**—**	45		
Payment on Divestiture of Assets	**—**	—		
Excess Free Funds Flow	**471**	786		

Gross Margin, Refining Margin and Unit Operating Expense

Gross Margin and Refining Margin are non-GAAP financial measures, or contain a non-GAAP financial measure, used to evaluate the performance of our downstream operations. We define Gross Margin as revenues less purchased product. We define Refining Margin as Gross Margin divided by barrels of crude oil unit throughput. Unit Operating Expenses are specified financial measures used to evaluate the performance of our upstream and downstream operations. We define Unit Operating Expense as operating expenses from our refineries and upgrader divided by barrels of crude oil unit throughput.

Canadian Refining

	Three Months Ended December 31, 2023				
	Basis of Refining Margin Calculation				
($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other (1)	Total Canadian Refining (2)
Revenues	1,191	263	1,454	103	1,557
Purchased Product	964	233	1,197	66	1,263
Gross Margin	227	30	257	37	294

	Operating Statistics		
	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
Heavy Crude Oil Unit Throughput (Mbbls/d)	73.6	26.7	100.3
Refining Margin ($/bbl)	33.48	11.96	27.74

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

Three Months Ended December 31, 2022					
	Basis of Refining Margin Calculation				
($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Refining [2]
Revenues	905	240	**1,145**	627	**1,772**
Purchased Product	574	170	**744**	580	**1,324**
Gross Margin	331	70	**401**	47	**448**

	Operating Statistics		
	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
Heavy Crude Oil Unit Throughput (Mbbls/d)	**68.4**	**25.9**	**94.3**
Refining Margin ($/bbl)	**52.60**	**29.36**	**46.21**

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

Year Ended December 31, 2023					
	Basis of Refining Margin Calculation				
($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Refining [2]
Revenues	**4,810**	**1,002**	**5,812**	**421**	**6,233**
Purchased Product	**3,890**	**744**	**4,634**	**285**	**4,919**
Gross Margin	**920**	**258**	**1,178**	**136**	**1,314**

	Operating Statistics		
	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
Heavy Crude Oil Unit Throughput (Mbbls/d)	**73.1**	**27.6**	**100.7**
Refining Margin ($/bbl)	**34.48**	**25.58**	**32.04**

(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.

Year Ended December 31, 2022					
	Basis of Refining Margin Calculation				
($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Refining [2]
Revenues	3,822	1,056	**4,878**	2,914	**7,792**
Purchased Product	2,918	809	**3,727**	2,662	**6,389**
Gross Margin	904	247	**1,151**	252	**1,403**

	Operating Statistics		
	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
Heavy Crude Oil Unit Throughput (Mbbls/d)	**68.7**	**24.2**	**92.9**
Refining Margin ($/bbl)	**36.04**	**27.91**	**33.92**

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

U.S. Refining

	Three Months Ended				
	2023				2022
($ millions)	**Q4**	Q3	Q2	Q1	Q4
Revenues [1] [2]	**6,847**	7,853	6,064	5,629	6,530
Purchased Product [1] [2]	**6,625**	6,467	5,364	4,898	5,669
Gross Margin	**222**	1,386	700	731	861
Crude Oil Unit Throughput (Mbbls/d)	**478.8**	555.9	442.5	359.2	379.0
Refining Margin ($/bbl)	**5.03**	27.10	17.40	22.62	24.70

	Year Ended December 31,	
($ millions)	**2023**	2022
Revenues [1] [2]	**26,393**	30,218
Purchased Product [1] [2]	**23,354**	26,020
Gross Margin	**3,039**	4,198
Crude Oil Unit Throughput (Mbbls/d)	**459.7**	400.8
Refining Margin ($/bbl)	**18.12**	28.70

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Comparative periods prior to the third quarter of 2023 reflect certain revisions. See Note 39 of the Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Per Unit DD&A

Per Unit DD&A is a specified financial measure used to measure DD&A on a per-unit basis in our upstream segments. We define Per Unit DD&A as the sum of upstream depletion on producing crude oil and natural gas properties and the associated asset retirement costs divided by sales volumes.

Netback Reconciliations

Netback per BOE 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 aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook. Netbacks per BOE reflect our margin on a per-barrel of oil equivalent basis. Netback is defined as gross sales less royalties, transportation and blending and operating expenses, and Netback per BOE is divided by sales volumes. Netbacks do not reflect non-cash write-downs or reversals of product inventory until it is realized when the product is sold, and exclude risk management activities. The sales price, transportation and blending expense, and sales volumes exclude the impact of purchased condensate. Condensate is blended with crude oil to transport it to market.

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

Oil Sands

	Basis of Netback Calculation						
Three Months Ended December 31, 2023 ($ millions)	Foster Creek	Christina Lake	Sunrise	Other Oil Sands (1)	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
Gross Sales	1,312	1,447	357	778	**3,894**	**2**	**3,896**
Royalties	353	366	32	86	**837**	**1**	**838**
Purchased Product	—	—	—	—	**—**	**—**	**—**
Transportation and Blending	200	161	58	39	**458**	**—**	**458**
Operating	174	167	65	203	**609**	**1**	**610**
Netback	585	753	202	450	**1,990**	**—**	**1,990**
Realized (Gain) Loss on Risk Management							**24**
Operating Margin							**1,966**

	Basis of Netback Calculation	Adjustments			
Three Months Ended December 31, 2023 ($ millions)	Total Oil Sands	Condensate	Third-party Sourced	Other (2)	Total Oil Sands (3)
Gross Sales	**3,896**	2,329	156	96	**6,477**
Royalties	**838**	—	—	3	**841**
Purchased Product	**—**	—	156	70	**226**
Transportation and Blending	**458**	2,329	—	22	**2,809**
Operating	**610**	—	—	5	**615**
Netback	**1,990**	—	—	(4)	**1,986**
Realized (Gain) Loss on Risk Management	**24**	—	—	—	**24**
Operating Margin	**1,966**	—	—	(4)	**1,962**

	Basis of Netback Calculation						
Three Months Ended December 31, 2022 ($ millions)	Foster Creek	Christina Lake	Sunrise	Other Oil Sands (1)	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
Gross Sales	1,282	1,453	222	745	**3,702**	**4**	**3,706**
Royalties	338	344	13	88	**783**	**1**	**784**
Purchased Product	—	—	—	—	**—**	**—**	**—**
Transportation and Blending	255	157	42	39	**493**	**—**	**493**
Operating	194	221	60	257	**732**	**3**	**735**
Netback	495	731	107	361	**1,694**	**—**	**1,694**
Realized (Gain) Loss on Risk Management							**59**
Operating Margin							**1,635**

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

(1) *Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.*
(2) *Other includes construction, transportation and blending margin.*
(3) *These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.*
(4) *Comparative periods prior to the third quarter of 2023 reflect certain revisions. See Note 39 of the Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.*

Year Ended December 31, 2023 ($ millions)	Basis of Netback Calculation						
	Foster Creek	Christina Lake	Sunrise	Other Oil Sands (1)	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
Gross Sales	5,347	5,848	1,298	3,208	**15,701**	**8**	**15,709**
Royalties	1,136	1,556	74	285	**3,051**	**5**	**3,056**
Purchased Product	—	—	—	—	**—**	**—**	**—**
Transportation and Blending	819	572	215	153	**1,759**	**—**	**1,759**
Operating	782	729	294	884	**2,689**	**9**	**2,698**
Netback	2,610	2,991	715	1,886	**8,202**	**(6)**	**8,196**
Realized (Gain) Loss on Risk Management							**17**
Operating Margin							**8,179**

Year Ended December 31, 2023 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced	Other (2)	Total Oil Sands (3)
Gross Sales	**15,709**	8,907	1,199	377	**26,192**
Royalties	**3,056**	—	—	3	**3,059**
Purchased Product	**—**	—	1,199	258	**1,457**
Transportation and Blending	**1,759**	8,907	—	108	**10,774**
Operating	**2,698**	—	—	18	**2,716**
Netback	**8,196**	—	—	(10)	**8,186**
Realized (Gain) Loss on Risk Management	**17**	—	—	—	**17**
Operating Margin	**8,179**	—	—	(10)	**8,169**

Year Ended December 31, 2022 ($ millions)	Basis of Netback Calculation						
	Foster Creek	Christina Lake	Sunrise	Other Oil Sands (1)	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
Gross Sales	6,723	7,951	950	3,967	**19,591**	**18**	**19,609**
Royalties	1,783	2,244	59	390	**4,476**	**6**	**4,482**
Purchased Product	—	—	—	—	**—**	**—**	**—**
Transportation and Blending	814	588	135	149	**1,686**	**—**	**1,686**
Operating	870	898	193	960	**2,921**	**20**	**2,941**
Netback	3,256	4,221	563	2,468	**10,508**	**(8)**	**10,500**
Realized (Gain) Loss on Risk Management							**1,527**
Operating Margin							**8,973**

Year Ended December 31, 2022 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands	Condensate	Third-party Sourced (4)	Other (2)	Total Oil Sands (3) (4)
Gross Sales	**19,609**	10,307	4,409	358	**34,683**
Royalties	**4,482**	—	—	11	**4,493**
Purchased Product	**—**	—	4,409	309	**4,718**
Transportation and Blending	**1,686**	10,307	—	43	**12,036**
Operating	**2,941**	—	—	(11)	**2,930**
Netback	**10,500**	—	—	6	**10,506**
Realized (Gain) Loss on Risk Management	**1,527**	—	—	—	**1,527**
Operating Margin	**8,973**	—	—	6	**8,979**

(1) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.
(2) Other includes construction, transportation and blending margin.
(3) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.
(4) Comparative periods prior to the third quarter of 2023 reflect certain revisions. See Note 39 of the Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Conventional

Three Months Ended December 31, 2023 ($ millions)	Basis of Netback Calculation **Conventional**	Adjustments **Third-party Sourced**	 **Other** (1)	**Conventional** (2)
Gross Sales	**331**	437	38	**806**
Royalties	**27**	—	—	**27**
Purchased Product	**—**	437	—	**437**
Transportation and Blending	**54**	—	24	**78**
Operating	**141**	—	5	**146**
Netback	**109**	—	9	**118**
Realized (Gain) Loss on Risk Management	**(5)**	—	—	**(5)**
Operating Margin	**114**	—	9	**123**

Three Months Ended December 31, 2022 ($ millions)	Basis of Netback Calculation **Conventional**	Adjustments **Third-party Sourced** (3)	 **Other** (1)	**Conventional** (2) (3)
Gross Sales	**555**	563	35	**1,153**
Royalties	**69**	—	1	**70**
Purchased Product	**—**	563	—	**563**
Transportation and Blending	**47**	—	12	**59**
Operating	**135**	—	3	**138**
Netback	**304**	—	19	**323**
Realized (Gain) Loss on Risk Management	**75**	—	—	**75**
Operating Margin	**229**	—	19	**248**

Year Ended December 31, 2023 ($ millions)	Basis of Netback Calculation **Conventional**	Adjustments **Third-party Sourced**	 **Other** (1)	**Conventional** (2)
Gross Sales	**1,390**	1,695	188	**3,273**
Royalties	**112**	—	—	**112**
Purchased Product	**—**	1,695	—	**1,695**
Transportation and Blending	**182**	—	116	**298**
Operating	**570**	—	20	**590**
Netback	**526**	—	52	**578**
Realized (Gain) Loss on Risk Management	**(5)**	—	—	**(5)**
Operating Margin	**531**	—	52	**583**

Year Ended December 31, 2022 ($ millions)	Basis of Netback Calculation **Conventional**	Adjustments **Third-party Sourced** (3)	 **Other** (1)	**Conventional** (2) (3)
Gross Sales	**2,238**	2,023	178	**4,439**
Royalties	**297**	—	1	**298**
Purchased Product	**—**	2,023	—	**2,023**
Transportation and Blending	**147**	—	103	**250**
Operating	**520**	—	21	**541**
Netback	**1,274**	—	53	**1,327**
Realized (Gain) Loss on Risk Management	**84**	8	—	**92**
Operating Margin	**1,190**	(8)	53	**1,235**

(1) Reflects Operating Margin from processing facilities.
(2) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.
(3) Comparative periods prior to the third quarter of 2023 reflect certain revisions. See Note 39 of the Consolidated Financial Statements and Prior Period Revisions found in the Advisory section of this MD&A for further details.

Offshore

	Basis of Netback Calculation					Adjustments		
Three Months Ended December 31, 2023 ($ millions)	**Atlantic**	**China**	**Indonesia (1)**	**Total Asia Pacific**	**Total Offshore**	**Equity Adjustment (1)**	**Other (2)**	**Total Offshore (3)**
Gross Sales	168	346	91	**437**	**605**	(91)	—	**514**
Royalties	4	30	18	**48**	**52**	(18)	—	**34**
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	7	—	—	**—**	**7**	—	—	**7**
Operating	71	29	17	**46**	**117**	(15)	1	**103**
Netback	86	287	56	**343**	**429**	(58)	(1)	**370**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**429**	(58)	(1)	**370**

	Basis of Netback Calculation					Adjustments		
Three Months Ended December 31, 2022 ($ millions)	**Atlantic**	**China**	**Indonesia (1)**	**Total Asia Pacific**	**Total Offshore**	**Equity Adjustment (1)**	**Other (2)**	**Total Offshore (3)**
Gross Sales	86	359	77	**436**	**522**	(77)	—	**445**
Royalties	1	20	27	**47**	**48**	(27)	—	**21**
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	3	—	—	**—**	**3**	—	—	**3**
Operating	48	24	17	**41**	**89**	(15)	10	**84**
Netback	34	315	33	**348**	**382**	(35)	(10)	**337**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**382**	(35)	(10)	**337**

	Basis of Netback Calculation					Adjustments		
Year Ended December 31, 2023 ($ millions)	**Atlantic**	**China**	**Indonesia (1)**	**Total Asia Pacific**	**Total Offshore**	**Equity Adjustment (1)**	**Other (2)**	**Total Offshore (3)**
Gross Sales	400	1,217	317	**1,534**	**1,934**	(317)	—	**1,617**
Royalties	15	84	74	**158**	**173**	(74)		**99**
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	16	—	—	**—**	**16**	—	—	**16**
Operating	239	111	58	**169**	**408**	(47)	23	**384**
Netback	130	1,022	185	**1,207**	**1,337**	(196)	(23)	**1,118**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**1,337**	(196)	(23)	**1,118**

	Basis of Netback Calculation					Adjustments		
Year Ended December 31, 2022 ($ millions)	**Atlantic**	**China**	**Indonesia (1)**	**Total Asia Pacific**	**Total Offshore**	**Equity Adjustment (1)**	**Other (2)**	**Total Offshore (3)**
Gross Sales	578	1,442	271	**1,713**	**2,291**	(271)	—	**2,020**
Royalties	(3)	80	116	**196**	**193**	(116)	—	**77**
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	15	—	—	**—**	**15**	—	—	**15**
Operating	175	99	51	**150**	**325**	(36)	29	**318**
Netback	391	1,263	104	**1,367**	**1,758**	(119)	(29)	**1,610**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**1,758**	(119)	(29)	**1,610**

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

Upstream Sales Volumes [1]

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

	Three Months Ended December 31,		Year Ended December 31,	
(MBOE/d)	**2023**	2022	**2023**	2022
Oil Sands				
Foster Creek	**192.6**	184.7	**187.4**	189.4
Christina Lake	**238.6**	246.5	**234.3**	247.5
Sunrise	**50.8**	42.0	**47.3**	30.2
Other Oil Sands	**123.4**	118.5	**120.5**	118.7
Total Oil Sands	**605.4**	591.7	**589.5**	585.8
Conventional	**123.8**	125.5	**119.9**	127.2
Offshore				
Atlantic	**15.0**	7.3	**9.6**	11.3
Asia Pacific				
China	**44.2**	47.1	**40.5**	48.2
Indonesia	**16.3**	12.8	**14.7**	10.5
Total Asia Pacific	**60.5**	59.9	**55.2**	58.7
Total Offshore	**75.5**	67.2	**64.8**	70.0
Sales Before Internal Consumption	**804.7**	784.4	**774.2**	783.0
Less: Internal Consumption [2]	**(104.5)**	(93.4)	**(92.6)**	(86.6)
Total Upstream Sales	**700.2**	691.0	**681.6**	696.4

(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 Earnings (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 Earnings (Loss). There was no impact to net earnings (loss), operating margin, segment income (loss), cash flows or financial position.

Change to Reporting Segments

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

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

($ millions)	Three Months Ended March 31, 2023 [1] Previously Reported	Revisions	Revised Balance	Three Months Ended June 30, 2023 [2] Previously Reported	Revisions	Revised Balance
Oil Sands Segment						
Gross Sales	5,911	(204)	**5,707**	6,556	(119)	**6,437**
Purchased Product	559	(204)	**355**	533	(119)	**414**
	5,352	—	**5,352**	6,023	—	**6,023**
Conventional Segment						
Gross Sales	1,031	6	**1,037**	615	5	**620**
Purchased Product	510	(27)	**483**	352	(15)	**337**
Transportation and Blending	48	33	**81**	46	20	**66**
	473	—	**473**	217	—	**217**
U.S. Refining Segment						
Gross Sales	5,860	(231)	**5,629**	6,198	(134)	**6,064**
Purchased Product	5,129	(231)	**4,898**	5,498	(134)	**5,364**
	731	—	**731**	700	—	**700**
Corporate and Eliminations Segment						
Gross Sales	(1,925)	429	**(1,496)**	(2,092)	248	**(1,844)**
Purchased Product	(1,499)	479	**(1,020)**	(1,757)	287	**(1,470)**
Transportation and Blending	(141)	(134)	**(275)**	(109)	(98)	**(207)**
Operating	(231)	84	**(147)**	(185)	59	**(126)**
	(54)	—	**(54)**	(41)	—	**(41)**
Consolidated						
Purchased Product	5,792	17	**5,809**	5,709	19	**5,728**
Transportation and Blending	2,853	(101)	**2,752**	2,641	(78)	**2,563**
Operating	1,552	84	**1,636**	1,541	59	**1,600**
	10,197	—	**10,197**	9,891	—	**9,891**

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

(2) *Includes revisions to gross sales and purchased product of $119 million in the Oil Sands segment, $15 million in the Conventional segment and $134 million in the U.S. Refining segment for the reasons noted above with an offsetting adjustment to the Corporate and Eliminations segment.*

($ millions)	Three Months Ended March 31, 2022 Previously Reported	Revisions	Segment Aggregation	Revised Balance	Three Months Ended June 30, 2022 Previously Reported	Revisions	Segment Aggregation	Revised Balance
Conventional Segment								
Gross Sales	1,112	25	—	**1,137**	1,079	34	—	**1,113**
Transportation and Blending	34	25	—	**59**	34	34	—	**68**
	1,078	—	—	**1,078**	1,045	—	—	**1,045**
Canadian Refining Segment								
Gross Sales	1,044	—	563	**1,607**	1,521	—	724	**2,245**
Purchased Product	804	2	529	**1,335**	1,296	(2)	686	**1,980**
Transportation and Blending	2	(2)	—	**—**	(2)	2	—	**—**
Operating	124	—	27	**151**	180	—	31	**211**
Depreciation, Depletion and Amortization	42	—	8	**50**	64	—	8	**72**
	72	—	(1)	**71**	(17)	—	(1)	**(18)**
Retail Segment								
Gross Sales	694	—	(694)	**—**	849	—	(849)	**—**
Purchased Product	660	—	(660)	**—**	811	—	(811)	**—**
Operating	27	—	(27)	**—**	31	—	(31)	**—**
Depreciation, Depletion and Amortization	8	—	(8)	**—**	8	—	(8)	**—**
	(1)	—	1	**—**	(1)	—	1	**—**
Corporate and Eliminations Segment								
Gross Sales	(1,761)	(25)	131	**(1,655)**	(1,782)	(34)	125	**(1,691)**
Purchased Product	(1,282)	39	131	**(1,112)**	(1,111)	69	125	**(917)**
Transportation and Blending	(221)	(110)	—	**(331)**	(188)	(145)	—	**(333)**
Operating	(267)	46	—	**(221)**	(395)	42	—	**(353)**
	9	—	—	**9**	(88)	—	—	**(88)**
Consolidated								
Purchased Product	7,482	41	—	**7,523**	9,396	67	—	**9,463**
Transportation and Blending	2,975	(87)	—	**2,888**	3,048	(109)	—	**2,939**
Operating	1,287	46	—	**1,333**	1,481	42	—	**1,523**
	11,744	—	—	**11,744**	13,925	—	—	**13,925**

($ millions)	Three Months Ended September 30, 2022 Previously Reported	Revisions	Segment Aggregation	Revised Balance	Three Months Ended December 31, 2022 Previously Reported	Revisions	Revised Balance
Oil Sands Segment							
Gross Sales	8,778	(14)	—	**8,764**	6,731	(78)	**6,653**
Purchased Product	1,933	(14)	—	**1,919**	594	(78)	**516**
	6,845	—	—	**6,845**	6,137	—	**6,137**
Conventional Segment							
Gross Sales	1,010	26	—	**1,036**	1,131	22	**1,153**
Transportation and Blending	38	26	—	**64**	37	22	**59**
	972	—	—	**972**	1,094	—	**1,094**
Canadian Refining Segment							
Gross Sales	1,478	—	690	**2,168**	1,772	—	**1,772**
Purchased Product	1,092	3	655	**1,750**	1,324	—	**1,324**
Transportation and Blending	3	(3)	—	**—**	—	—	**—**
Operating	134	—	38	**172**	170	—	**170**
Depreciation, Depletion and Amortization	37	—	5	**42**	44	—	**44**
	212	—	(8)	**204**	234	—	**234**
Retail Segment							
Gross Sales	881	—	(881)	**—**	—	—	**—**
Purchased Product	846	—	(846)	**—**	—	—	**—**
Operating	38	—	(38)	**—**	—	—	**—**
Depreciation, Depletion and Amortization	5	—	(5)	**—**	—	—	**—**
	(8)	—	8	**—**	—	—	**—**
U.S. Refining Segment							
Gross Sales	8,719	(14)	—	**8,705**	6,608	(78)	**6,530**
Purchased Product	7,944	(14)	—	**7,930**	5,747	(78)	**5,669**
	775	—	—	**775**	861	—	**861**
Corporate and Eliminations Segment							
Gross Sales	(2,619)	2	191	**(2,426)**	(1,749)	134	**(1,615)**
Purchased Product	(2,267)	65	191	**(2,011)**	(1,320)	168	**(1,152)**
Transportation and Blending	(119)	(128)	—	**(247)**	(136)	(128)	**(264)**
Operating	(256)	65	—	**(191)**	(352)	94	**(258)**
	23	—	—	**23**	59	—	**59**
Consolidated							
Purchased Product	10,012	40	—	**10,052**	6,908	12	**6,920**
Transportation and Blending	2,684	(105)	—	**2,579**	2,826	(106)	**2,720**
Operating	1,439	65	—	**1,504**	1,362	94	**1,456**
	14,135	—	—	**14,135**	11,096	—	**11,096**

	Twelve Months Ended December 31, 2022		
($ millions)	Previously Reported	Revisions	Revised Balance
Oil Sands Segment			
Gross Sales	34,775	(92)	**34,683**
Purchased Product	4,810	(92)	**4,718**
	29,965	—	**29,965**
Conventional Segment			
Gross Sales	4,332	107	**4,439**
Transportation and Blending	143	107	**250**
	4,189	—	**4,189**
U.S. Refining Segment			
Gross Sales	30,310	(92)	**30,218**
Purchased Product	26,112	(92)	**26,020**
	4,198	—	**4,198**
Corporate and Eliminations Segment			
Gross Sales	(7,464)	77	**(7,387)**
Purchased Product	(5,533)	341	**(5,192)**
Transportation and Blending	(664)	(511)	**(1,175)**
Operating	(1,270)	247	**(1,023)**
	3	—	**3**
Consolidated			
Purchased Product	33,801	157	**33,958**
Transportation and Blending	11,530	(404)	**11,126**
Operating	5,569	247	**5,816**
	50,900	—	**50,900**

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