Cenovus Energy Inc.

Management's Discussion and Analysis (unaudited)

For the Period Ended March 31, 2023

(Canadian Dollars)

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the period ended March 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, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) dated April 25, 2023 should be read in conjunction with our March 31, 2023 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2022 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2022 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of April 25, 2023 unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus management ("Management") prepared the MD&A. The Audit Committee of the Cenovus Board of Directors ("the Board"), reviewed and recommended the MD&A for approval by the Board, which occurred on April 25, 2023. Additional information about Cenovus, including our quarterly and annual reports, Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, 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, does not constitute part of this MD&A.

Basis of Presentation

This MD&A and the interim Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, (which includes references to "dollar" or "$"), except where another currency has been 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 the second largest Canadian-based crude oil and natural gas producer, with upstream operations in Canada and the Asia Pacific region, and the second largest Canadian-based refiner and upgrader, 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 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 and natural gas production through to the sale of finished products such as transportation fuels.

Our Strategy and Key Priorities for 2023

At Cenovus, our purpose is to energize the world to make people's lives better. Our strategy is focused on maximizing shareholder value through competitive cost structures and optimizing margins, while delivering top-tier safety performance and sustainability leadership. The Company prioritizes Free Funds Flow generation through all price cycles to manage our balance sheet, increase shareholder returns through dividend growth and share repurchases, reinvest in our business and diversify our portfolio. On December 6, 2022, we released our 2023 budget. Our 2023 guidance, as updated on April 25, 2023, is available on our website at cenovus.com. For further details see the Operating and Financial Results section of this MD&A.

In 2023, we aim to deliver on our strategy through five key objectives.

Top-Tier Safety and Operational Performance

Safe and reliable operations are our number one priority. We strive to ensure safe and reliable operations across our portfolio, including top-tier health and safety performance.

We will continue to target improved operating performance, including the safe return of the Superior Refinery to full operations and integration of the Toledo Refinery with a focus on demonstrating consistent and reliable performance at our operated assets.

Sustainability Leadership

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. Our five ESG focus areas are:

- Climate & GHG emissions.
- Water stewardship.
- Biodiversity.
- Indigenous reconciliation.
- Inclusion & diversity.

Additional information on Cenovus's efforts and performance across the ESG focus areas, including our ESG targets and plans to achieve them, are available in Cenovus's 2021 ESG report on our website at cenovus.com.

Cost Leadership

We aim to maximize shareholder value through competitive cost structures and optimized margins. While we strive to optimize our cost structure in all areas of our business, one of our focus areas is to optimize infrastructure, reduce operating and capital costs, and reduce GHG emissions at our conventional assets.

Financial Discipline and Free Funds Flow Growth

We are focused on achieving and maintaining targeted debt levels while positioning Cenovus for resiliency through all commodity price cycles. We plan to continue to deliver meaningful returns to shareholders in alignment with our financial and shareholder returns framework.

Returns-Focused Capital Allocation

We continue to take a disciplined approach to allocating capital to projects that generate returns at the bottom of the commodity price cycle and provide opportunities to sustainably grow shareholder returns.

We plan to materially progress the West White Rose project to deliver first oil in 2026.

Our Operations

The Company operates through the following reportable segments:

Upstream Segments

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

Downstream Segments

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

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 internal usage of natural gas production between segments, transloading services provided to the Oil Sands segment by the Company's crude-by-rail terminal, crude oil production used as feedstock by the Canadian Manufacturing and U.S. Manufacturing segments, the sale of condensate extracted from blended crude oil production in the Canadian Manufacturing segment and sold to the Oil Sands segment, and unrealized profits in inventory. Eliminations are recorded based on current market prices.

QUARTERLY RESULTS OVERVIEW

We delivered safe operations during the first quarter of 2023. Our financial results reflect declining commodity prices in our upstream business and operational challenges in our downstream business. In addition, production volumes declined in our upstream business primarily related to lower volumes at our Oil Sands assets as we prepare for the start-up of new well pads. In our downstream business, the majority of the unplanned operational issues, weather-related impacts and third-party pipeline outages experienced in December were resolved. The Lloydminster Upgrader (the "Upgrader") returned to full rates in the middle of January. At the Wood River and Borger refineries, we had unplanned outages and commenced planned turnarounds in the first quarter. The Borger turnaround and the first phase of the Wood River turnaround were completed in April. The Lima Refinery and Lloydminster Refinery ran at near full rates.

Refined product prices declined in the first quarter compared with the fourth and first quarters of 2022. Average market crack spreads declined slightly compared with the fourth quarter of 2022 and increased significantly compared with the first quarter of 2022. WTI averaged approximately US$76.13 per barrel, a decline of eight percent and 19 percent from the fourth and first quarters of 2022, respectively. The WTI-WCS differential at Hardisty of US$24.77 per barrel narrowed slightly compared with the fourth quarter of 2022, and widened significantly from the first quarter of 2022 (US$14.53 per barrel).

Summary of Quarterly Results

	2023	2022				2021			
($ millions, except where indicated)	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Upstream Production Volumes [1] (MBOE/d)	**779.0**	806.9	777.9	761.5	798.6	825.3	804.8	765.9	769.3
Downstream Crude Oil Unit Throughput [2] (Mbbls/d)	**457.9**	473.3	533.5	457.3	501.8	469.9	554.1	539.0	469.1
Downstream Production Volumes (Mbbls/d)	**485.4**	495.1	567.0	477.1	534.9	494.8	576.9	557.0	498.4
Revenues	**12,262**	14,063	17,471	19,165	16,198	13,726	12,701	10,637	9,293
Operating Margin [3]	**2,102**	2,782	3,339	4,678	3,464	2,600	2,710	2,184	1,879
Cash From (Used In) Operating Activities	**(286)**	2,970	4,089	2,979	1,365	2,184	2,138	1,369	228
Adjusted Funds Flow [3]	**1,395**	2,346	2,951	3,098	2,583	1,948	2,342	1,817	1,141
Per Share - Basic [3] ($)	**0.73**	1.22	1.53	1.57	1.30	0.97	1.16	0.90	0.57
Per Share - Diluted [3] ($)	**0.71**	1.19	1.49	1.53	1.27	0.97	1.15	0.89	0.56
Capital Investment	**1,101**	1,274	866	822	746	835	647	534	547
Free Funds Flow [3]	**294**	1,072	2,085	2,276	1,837	1,113	1,695	1,283	594
Excess Free Funds Flow [3]	**(499)**	786	1,756	2,020	2,615	1,169	1,626	1,244	462
Net Earnings (Loss) [4]	**636**	784	1,609	2,432	1,625	(408)	551	224	220
Per Share - Basic ($)	**0.33**	0.40	0.83	1.23	0.81	(0.21)	0.27	0.11	0.10
Per Share - Diluted ($)	**0.32**	0.39	0.81	1.19	0.79	(0.21)	0.27	0.11	0.10
Total Assets	**54,000**	55,869	55,086	55,894	55,655	54,104	54,594	53,384	53,378
Total Long-Term Liabilities	**19,917**	20,259	19,378	20,742	21,889	23,191	22,929	22,972	24,266
Long-Term Debt, Including Current Portion	**8,681**	8,691	8,774	11,228	11,744	12,385	12,986	13,380	13,947
Net Debt	**6,632**	4,282	5,280	7,535	8,407	9,591	11,024	12,390	13,340
Cash Returns to Shareholders									
Common Shares – Base Dividends	**200**	201	205	207	69	70	35	36	35
Base Dividends Per Common Share ($)	**0.105**	0.105	0.105	0.105	0.035	0.035	0.018	0.018	0.018
Common Shares – Variable Dividends	**—**	219	—	—	—	—	—	—	—
Variable Dividends Per Common Share ($)	**—**	0.114	—	—	—	—	—	—	—
Purchase of Common Shares Under NCIB	**40**	387	659	1,018	466	265	—	—	—
Preferred Share Dividends [5]	**18**	—	9	8	9	8	9	8	9

(1) Refer to the Operating and Financial Results section of this MD&A for a summary of total upstream production by product type.
(2) Represents Cenovus's net interest in refining operations.
(3) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(4) Net earnings (loss) for all periods in the table above is the same as net earnings (loss) from continuing operations.
(5) Preferred share dividends declared on November 1, 2022, were paid on January 3, 2023. Preferred share dividends declared on February 15, 2023, were paid on March 31, 2023.

Upstream production averaged 779.0 thousand BOE per day in the first quarter, compared with 806.9 thousand BOE per day in the fourth quarter of 2022 and 798.6 thousand BOE per day in the first quarter of 2022. See the Operating and Financial Results section of this MD&A for a summary of upstream production by product type.

Downstream crude oil throughput averaged 457.9 thousand barrels per day in the first quarter, a decrease of 15.4 thousand barrels per day compared with the fourth quarter of 2022, and a decline of 43.9 thousand barrels per day compared with the first quarter of 2022. Downstream refined products production volumes averaged 485.4 thousand barrels per day in the first quarter, a decrease of 9.7 thousand barrels per day compared with the fourth quarter of 2022, and a decline of 49.5 thousand barrels per day compared with the first quarter of 2022.

On February 28, 2023, 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"). The refinery partially restarted in April. At the Superior Refinery, we started circulating hydrocarbons in February and introduced crude oil in mid-March.

Revenue decreased 13 percent to $12.3 billion from the fourth quarter of 2022 and 24 percent from the first quarter of 2022, primarily due to lower commodity pricing. Our realized sales price from our upstream operations was $60.83 per BOE in the first quarter of 2023 down 13 percent compared with $69.77 per BOE in the fourth quarter of 2022 and down 35 percent compared with $94.12 per BOE in the first quarter of 2022.

In our Canadian downstream operations, realized per barrel refining margins declined six percent from the fourth quarter of 2022, and nearly doubled from the first quarter of 2022. Realized per barrel refining margins in our U.S. downstream operations decreased eight percent and 20 percent from the fourth and first quarter of 2022, respectively.

Operating margin was $2.1 billion, a decrease of 24 percent and 39 percent from the fourth and first quarters of 2022, respectively, primarily due to lower crude oil benchmark pricing. Cash used in operating activities was $286 million, compared with cash from operating activities of $3.0 billion and $1.4 billion in the fourth and first quarters of 2022, respectively. In addition to the decline in Operating Margin, cash from (used in) operating activities was negatively impacted by changes in non-cash working capital of $1.6 billion, driven largely by the payment of the December 31, 2022, $1.2 billion income tax liability. Adjusted Funds Flow was $1.4 billion in the first quarter of 2023, a decrease of 41 percent from the fourth quarter of 2022, and 46 percent from the first quarter of 2022.

Net Debt increased $2.4 billion to $6.6 billion during the quarter primarily due to:

- Changes in non-cash working capital as discussed above.
- Capital investment of $1.1 billion.
- Declines in operating margin as discussed above.
- Cash paid of $465 million primarily related to the close of the Toledo Acquisition.
- Returns to common shareholders of $240 million, including $200 million through base dividends of $0.105 per common share and the purchase of 1.6 million common shares for $40 million through our NCIB.
- Contingent payment of $92 million in connection with the acquisition of the remaining 50 percent interest in Sunrise.

Excess Free Funds Flow was negative $499 million.

On April 25, 2023, our second quarter dividend increased 33 percent from the first quarter dividend declared in February 2023. The increase is aligned with our long-term value proposition and our plans to sustainably grow our base dividend. The Board declared a second quarter base dividend of $0.140 per common share. The dividend is payable on June 30, 2023, to common shareholders of record as at June 15, 2023. The Board also declared second quarter dividends for our preferred shares of $9 million, payable on June 30, 2023, to preferred shareholders of record as at June 15, 2023.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results — Upstream

	Three Months Ended March 31,		
	2023	Percent Change	2022
Upstream Production Volumes by Segment [1] (MBOE/d)			
Oil Sands	**589.5**	**(1)**	597.0
Conventional	**123.9**	**(1)**	125.2
Offshore	**65.6**	**(14)**	76.4
Total Production Volumes	**779.0**	**(2)**	798.6
Upstream Production Volumes by Product			
Bitumen (Mbbls/d)	**570.7**	**(1)**	578.8
Heavy Crude Oil (Mbbls/d)	**16.8**	**4**	16.2
Light Crude Oil (Mbbls/d)	**15.3**	**(30)**	21.9
NGLs (Mbbls/d)	**33.4**	**(11)**	37.6
Conventional Natural Gas (MMcf/d)	**857.0**	**(1)**	865.3
Total Production Volumes (MBOE/d)	**779.0**	**(2)**	798.6
Total Upstream Sales Volumes [2] (MBOE/d)	**683.1**	**(6)**	724.5
Netback [3] [4] ($/BOE)	**29.11**	**(50)**	58.74

(1) Refer to the Oil Sands, Conventional or Offshore Reportable Segments section of this MD&A for a summary of production by product type.
(2) Total upstream sales volumes exclude natural gas volumes used for internal consumption by the Oil Sands segment of 541 MMcf per day for the three months ended March 31, 2023 (527 MMcf per day for the three months ended March 31, 2022).
(3) Upstream revenue as found in Note 1 of the interim Consolidated Financial Statements was $6.8 billion for the three months ended March 31, 2023 ($9.7 billion for the three months ended March 31, 2022).
(4) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.

In the first quarter of 2023, total crude oil, NGLs and natural gas production decreased slightly from the first quarter of 2022. The factors below increased production in 2023 compared with 2022:

- On August 31, 2022, we acquired the remaining 50 percent interest in Sunrise (the "Sunrise Acquisition") from BP Canada Energy Group ULC ("BP Canada").
- First oil at the Spruce Lake North thermal plant in the third quarter of 2022.
- First gas production at the MBH and MDA fields in Indonesia in the fourth quarter of 2022.

The factors below decreased production in 2023 compared with 2022:

- Changes to Liwan 3-1 production sharing contracts in China in the second quarter of 2022, concluding the amendment that temporarily increased sales volumes.
- The disposition of the Tucker and Wembley assets in the first quarter of 2022.
- The reduction of our working interest in the White Rose field and satellite extensions to our partner on May 31, 2022, by 12.5 percent.
- Declines at Foster Creek and Christina Lake as we prepare for the start-up of new well pads.
- Wells taken offline for redevelopment programs at our Sunrise and Lloydminster thermal assets.

Selected Operating Results — Downstream

	Three Months Ended March 31,		
	2023	**Percent Change**	2022
Downstream Crude Oil Unit Throughput (Mbbls/d)			
Canadian Manufacturing	**98.7**	**1**	98.1
U.S. Manufacturing	**359.2**	**(11)**	403.7
Total Throughput	**457.9**	**(9)**	501.8
Downstream Production Volumes (Mbbls/d)			
Canadian Manufacturing	**106.4**	**2**	104.3
U.S. Manufacturing	**379.0**	**(12)**	430.6
Total Downstream Production	**485.4**	**(9)**	534.9

In the Canadian Manufacturing segment, throughput was relatively unchanged year-over-year. The Upgrader was impacted by cold weather and operational outages in the fourth quarter of 2022 and returned to full rates by the middle of January. Throughput at the Upgrader was impacted by maintenance activities in the first quarter of 2022. The Lloydminster Refinery operated at or near capacity throughout the first quarter of 2023 and 2022.

In the U.S. Manufacturing segment, total throughput decreased 44.5 thousand barrels per day to 359.2 thousand barrels per day in the first quarter of 2023 compared with the first quarter of 2022. Total refined products output decreased 49.5 thousand barrels per day to 485.4 thousand barrels per day.

- The Lima Refinery performed very well. Throughput increased 31.1 thousand barrels per day to 167.2 thousand barrels per day.
- Throughput was relatively consistent at the Wood River and Borger refineries compared with 2022. Operational outages stemming from the fourth quarter of 2022 were resolved, including a main component for jet fuel production returning to service in mid-March. The outage had a significant negative impact on our gross margin.
- At the end of February, the first phase of a planned turnaround commenced at the Wood River Refinery which was completed in early April. The second phase, which will also impact throughput, started in mid-April and is expected to be completed in May.
- At the Borger Refinery a planned turnaround began at the end of March, which was completed by late April.
- On February 28, 2023, we closed the purchase of the remaining 50 percent interest in the Toledo Refinery from BP. The refinery partially restarted in April and is ramping up through the second quarter. In the first quarter of 2022, our share of throughput at the refinery was 72.1 thousand barrels per day.
- The Superior Refinery introduced crude oil starting in mid-March 2023 and is ramping up through the second quarter.

Selected Consolidated Financial Results

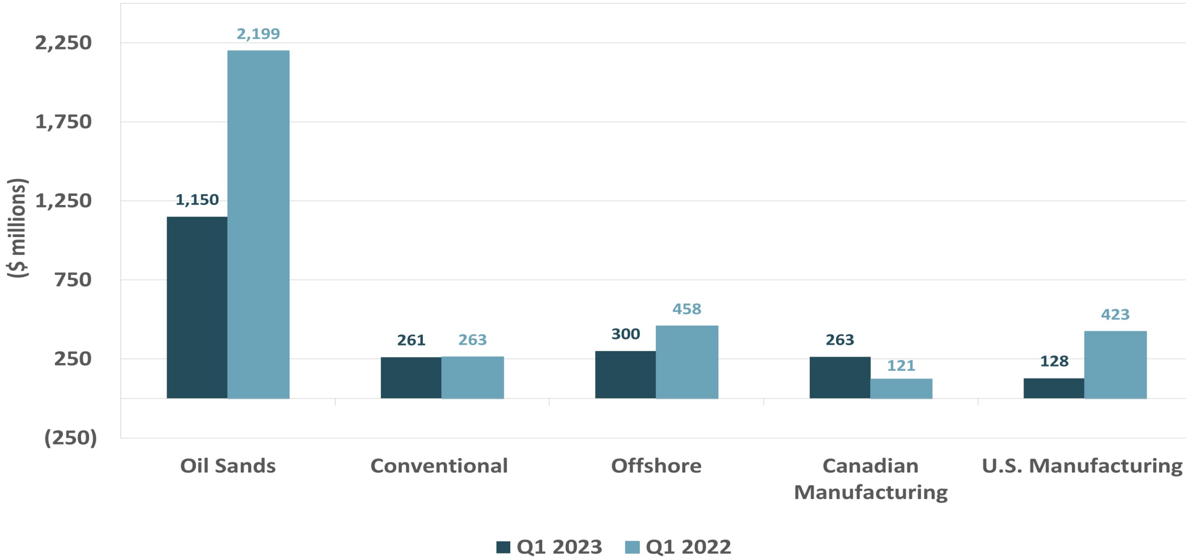
Operating Margin

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.

	Three Months Ended March 31,	
($ millions)	**2023**	2022
Gross Sales	**14,783**	19,013
Less: Royalties	**596**	1,185
Revenues	**14,187**	17,828
Expenses		
Purchased Product	**7,291**	8,635
Transportation and Blending	**2,994**	3,194
Operating Expenses	**1,783**	1,554
Realized (Gain) Loss on Risk Management Activities	**17**	981
Operating Margin	**2,102**	3,464

Operating Margin by Segment

Three Months Ended March 31, 2023



Operating Margin decreased in the three months ended March 31, 2023, compared with the same period in 2022, primarily due to:

- Lower realized crude oil sales prices resulting from lower benchmark pricing.
- Decreased sales volumes from our upstream business.
- Higher operating expenses in both our upstream and downstream operations.
- Lower gross margins in the U.S. Manufacturing segment resulting from the higher cost of feedstock processed in the first quarter of 2023 compared with 2022, lower refined product pricing and higher RINs costs.
- Planned and unplanned outages in our downstream operations in the first quarter of 2023, which impacted sales volumes.
- Higher transportation expenses from our upstream operations, primarily due to increased tariff rates and higher sales volumes to the U.S.

These decreases in Operating Margin were partially offset by:

- Significantly lower realized risk management losses on the settlement of benchmark prices relative to our risk management contract prices, due to a rising commodity price environment in the first quarter of 2022 and management's decision to liquidate our WTI positions related to crude oil sales price risk management in the second quarter of 2022.
- Decreased royalties in the Oil Sands segment, resulting from lower crude oil benchmark pricing.
- Lower blending costs due to decreased condensate prices.
- Higher gross margins in the Canadian Manufacturing segment due to a higher upgrading differential and higher margins on asphalt and industrial products.

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

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

	Three Months Ended March 31,	
($ millions)	**2023**	2022
Cash From (Used in) Operating Activities	**(286)**	1,365
(Add) Deduct:		
Settlement of Decommissioning Liabilities	**(48)**	(19)
Net Change in Non-Cash Working Capital	**(1,633)**	(1,199)
Adjusted Funds Flow	**1,395**	2,583

Cash used in operating activities was $286 million in the first quarter of 2023, compared with cash from operating activities of $1.4 billion in the same period in 2022. The change was primarily due to lower Operating Margin and changes in non-cash working capital. The net change in non-cash working capital in the first quarter of 2023 was $1.6 billion (2022 – $1.2 billion) mainly due to paying the December 31, 2022, $1.2 billion income tax liability. In addition, accounts payable decreased due to lower cost of feedstock, decreased natural gas prices and lower royalties.

Adjusted Funds Flow is lower in the three months ended March 31, 2023, compared with the same period in 2022, primarily due to decreased Operating Margin, as discussed above. The decrease was partially offset by the 2022 contingent payment associated with the 2017 acquisition of a 50 percent interest in the FCCL Partnership.

Net Earnings (Loss)

($ millions)	
Net Earnings (Loss), for the Three Months Ended March 31, 2022	**1,625**
Increase (Decrease) due to:	
Operating Margin	**(1,362)**
Corporate and Eliminations:	
General and Administrative	**41**
Finance Costs	**35**
Integration and Transaction Costs	**4**
Unrealized Foreign Exchange Gain (Loss)	**(153)**
Revaluation Gain (Loss)	**(33)**
Re-measurement of Contingent Payments	**219**
Gain (Loss) on Divestiture of Assets	**(241)**
Other Income (Loss), net	**(364)**
Other (1)	**(11)**
Unrealized Risk Management Gain (Loss)	**353**
Depreciation, Depletion and Amortization	**(75)**
Exploration Expense	**12**
Income Tax (Expense) Recovery	**586**
Net Earnings (Loss), for the Three Months Ended March 31, 2023	**636**

(1) Includes Corporate and Eliminations revenues, purchased product, transportation and blending expenses, operating expenses and (gain) loss on risk management; share of income (loss) from equity-accounted affiliates; interest income and realized foreign exchange (gains) losses.

Net earnings in the first quarter of 2023 decreased compared with the same period in 2022 due to declines in Operating Margin, lower other income due to the 2022 insurance proceeds related to the Superior Refinery incident, gains on the divestiture of the Tucker and Wembley assets in 2022 compared with minor divestitures in 2023, and unrealized foreign exchange losses compared with unrealized foreign exchange gains in 2022. The decrease in net earnings was partially offset by a deferred income tax recovery related to the Toledo Acquisition, unrealized risk management gains compared with losses in 2022 and the re-measurement of our contingent payments.

Net Debt

As at ($ millions)	**March 31, 2023**	December 31, 2022
Short-Term Borrowings	**—**	115
Current Portion of Long-Term Debt	**—**	—
Long-Term Portion of Long-Term Debt	**8,681**	8,691
Total Debt	**8,681**	8,806
Less: Cash and Cash Equivalents	**(2,049)**	(4,524)
Net Debt	**6,632**	4,282

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

Capital Investment [1]

($ millions)	Three Months Ended March 31, 2023	2022
Upstream		
Oil Sands	**635**	375
Conventional	**141**	88
Offshore	**100**	53
Total Upstream	**876**	516
Downstream		
Canadian Manufacturing	**27**	15
U.S. Manufacturing	**194**	207
Total Downstream	**221**	222
Corporate and Eliminations	**4**	8
Total Capital Investment	**1,101**	746

(1) Includes expenditures on property, plant and equipment ("PP&E"), exploration and evaluation ("E&E") assets, and capitalized interest. Excludes cost incurred in our equity-accounted investment in Indonesia.

Oil Sands capital investment in the first quarter of 2023 was mainly for sustaining activities at Christina Lake, Foster Creek, the Lloydminster thermal assets and Sunrise, and the drilling of stratigraphic test wells as part of our integrated winter program.

Conventional capital investment in the first quarter of 2023 focused on drilling, completion and tie-in activities, and infrastructure projects to support multi-year development.

Offshore capital investment in the first quarter of 2023 was primarily for the West White Rose project, and Terra Nova asset life extension ("ALE") project.

U.S. Manufacturing capital investment in the first quarter of 2023 focused primarily on the Superior Refinery rebuild, and refining reliability initiatives at the Wood River and Borger refineries.

Drilling Activity

	Net Stratigraphic Test Wells and Observation Wells		Net Production Wells [1]	
Three Months Ended March 31,	**2023**	2022	**2023**	2022
Foster Creek	**87**	68	**3**	5
Christina Lake	**53**	—	**3**	8
Sunrise	**38**	15	**—**	2
Lloydminster Thermal	**1**	1	**—**	19
Lloydminster Conventional Heavy Oil	**1**	—	**3**	—
Other [2]	**3**	6	**—**	—
	183	90	**9**	34

(1) SAGD well pairs in the Oil Sands segment are counted as a single producing well.
(2) Includes new resource plays and the Tucker asset sold on January 31, 2022.

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

	Three Months Ended March 31, 2023			Three Months Ended March 31, 2022		
(net wells)	**Drilled**	**Completed**	**Tied-in**	Drilled	Completed	Tied-in
Conventional	**14**	**15**	**16**	13	20	20

In the Offshore segment, we drilled and completed one (0.4 net) planned development well at the MAC field in Indonesia in the first quarter of 2023 (2022 — drilled and completed two (0.8 net) planned development wells at the MBH field in Indonesia).

Future Capital Investment

Future Capital Investment is a specified financial measure. See the Specified Financial Measures Advisory of this MD&A. Our 2023 guidance, as updated on April 25, 2023, is available on our website at cenovus.com.

Our updated guidance reflects an updated outlook for commodity prices and cash tax, in addition to:

- Lower production guidance, which includes the removal of Terra Nova production volumes.
- Lower throughput at our non-operated refineries due to unplanned outages in the first quarter and a longer ramp up period for the Toledo Refinery.
- A decline in Oil Sands unit operating expenses to reflect lower natural gas price assumptions for the remainder of 2023 and an increase in U.S. Manufacturing and Atlantic unit operating expenses as a result of reductions in throughput and production, respectively.

The following table shows guidance for 2023:

	Capital Investment ($ millions)	**Production** (MBOE/d)	**Crude Throughput** (Mbbls/d)
Upstream			
Oil Sands	**2,200 - 2,400**	**582 - 642**	
Conventional	**350 - 450**	**125 - 140**	
Offshore	**600 - 700**	**55 - 68**	
Downstream	**800 - 900**		**580 - 610**
Corporate and Eliminations	**40 - 50**		

2023 guidance for total capital investment is between $4.0 billion and $4.5 billion. This includes sustaining capital of approximately $2.8 billion, and between $1.2 billion and $1.7 billion in optimization and growth capital. Capital investment guidance did not change as part of the April 25, 2023 update.

Further information on the changes in our financial and operating results can be found in the Reportable Segments section of this MD&A. Information on our risk management activities can be found in the Risk Management and Risk Factors section of this MD&A and in the notes to the interim Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates [(1)]

(Average US$/bbl, unless otherwise indicated)	Q1 2023	Percent Change	Q1 2022	Q4 2022
Dated Brent	**81.27**	**(20)**	101.41	88.71
WTI	**76.13**	**(19)**	94.29	82.65
Differential Dated Brent-WTI	**5.14**	**(28)**	7.12	6.06
WCS at Hardisty	**51.36**	**(36)**	79.76	56.99
Differential WTI-WCS	**24.77**	**70**	14.53	25.66
WCS (C$/bbl)	**69.44**	**(31)**	101.01	77.42
WCS at Nederland	**62.49**	**(30)**	89.19	67.65
Differential WTI-WCS at Nederland	**13.64**	**167**	5.10	15.00
Condensate (C5 @ Edmonton)	**79.87**	**(17)**	96.09	83.40
Differential WTI-Condensate (Premium)/Discount	**(3.74)**	**108**	(1.80)	(0.75)
Differential WCS [(2)]-Condensate (Premium)/Discount	**(28.51)**	**75**	(16.33)	(26.41)
Average (C$/bbl)	**107.95**	**(11)**	121.69	113.25
Synthetic @ Edmonton	**78.18**	**(16)**	93.05	86.79
Differential WTI-Synthetic (Premium)/Discount	**(2.05)**	**(265)**	1.24	(4.14)
Refined Product Prices				
Chicago Regular Unleaded Gasoline ("RUL")	**99.82**	**(9)**	109.16	102.80
Chicago Ultra-low Sulphur Diesel ("ULSD")	**115.39**	**(4)**	119.60	140.95
Refining Benchmarks				
Chicago 3-2-1 Crack Spread [(3)]	**28.88**	**57**	18.35	32.87
Group 3 3-2-1 Crack Spread [(3)]	**31.35**	**57**	19.94	29.99
Renewable Identification Numbers ("RINs")	**8.20**	**27**	6.44	8.54
Natural Gas Prices				
AECO (C$/Mcf)	**4.34**	**(5)**	4.59	5.58
NYMEX (US$/Mcf)	**3.42**	**(31)**	4.95	6.26
Foreign Exchange Rates				
US$ per C$1 - Average	**0.739**	**(6)**	0.790	0.737
US$ per C$1 - End of Period	**0.739**	**(8)**	0.800	0.738
RMB per C$1 - Average	**5.059**	**1**	5.014	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.

Crude Oil and Condensate Benchmarks

In the first quarter of 2023, global crude oil prices continued to decline compared with all quarters in 2022. Prices declined due to macroeconomic slowdown concerns and resilient Russian exports. Concerns over Russian supply disruptions eased and nearly all short-term supply sources have been accessed to meet demand, including unprecedented releases of U.S. government strategic petroleum reserves ("SPRs") in 2022. Seasonal demand weakness also impacted the decline from the fourth quarter of 2022. On April 2, 2023, OPEC+ announced a cut to the group's production quotas which is supportive of pricing.

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.

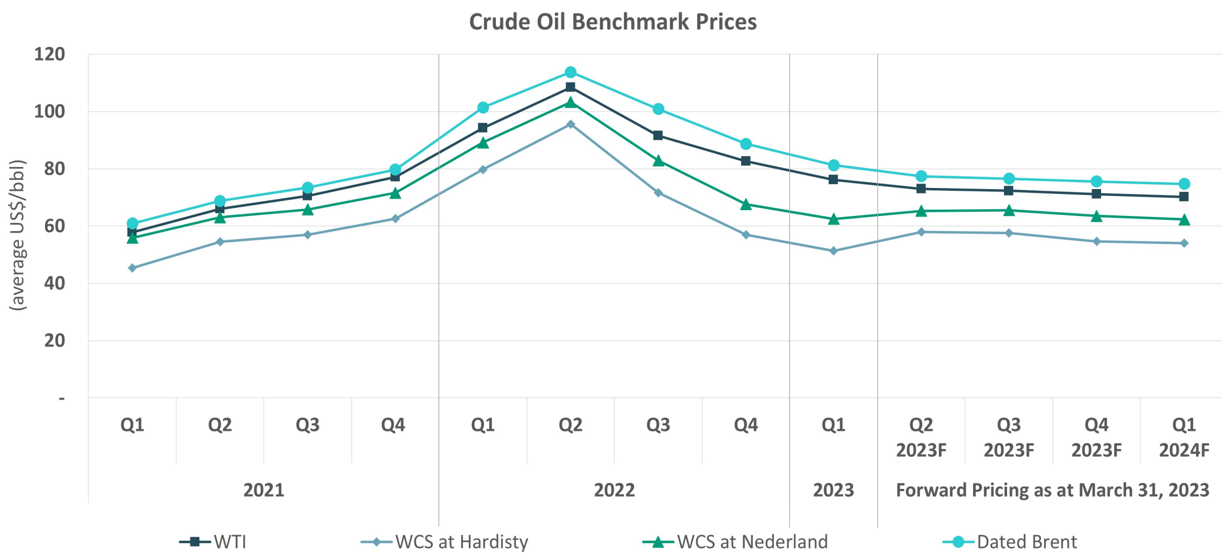
The price received for our Atlantic crude oil and Asia Pacific NGLs is primarily driven by the price of Brent. The Brent-WTI differential narrowed slightly compared with the first and fourth quarters of 2022 due to declining inventories at Cushing and strong crude demand from Midwest refiners.

WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WCS at Hardisty differential to WTI is a function of the quality differential of light and heavy crude and the cost of transport. In the first quarter of 2023, the average WTI-WCS differential at Hardisty widened significantly compared with the first quarter of 2022, primarily due to a wider quality differential at the U.S. Gulf Coast ("USGC") outlined below, as well as higher production activity in Western Canada.

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 widened significantly from the first quarter of 2022, mainly attributed to reduced demand due to planned and unplanned refinery maintenance, high global refining utilization, volatile refined product pricing and increased supply due to incremental medium and heavy oil barrels entering the market from OPEC.

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

In the first quarter of 2023, synthetic crude at Edmonton was at a premium to WTI compared with a discount in the first quarter of 2022. The premium decreased compared with the fourth quarter of 2022. Synthetic crude prices were particularly elevated in the second half of 2022 as a result of widespread upgrader maintenance in Western Canada and strong refinery demand for light crude oil.



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 22 percent to 35 percent. The WCS-Condensate differential, which widened to US$28.51 per barrel in the first quarter of 2023, 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.

The average Edmonton condensate premium to WTI widened compared with the first and fourth quarters of 2022 as Alberta demand for condensate was strong and supply remains tight.

Refining Benchmarks

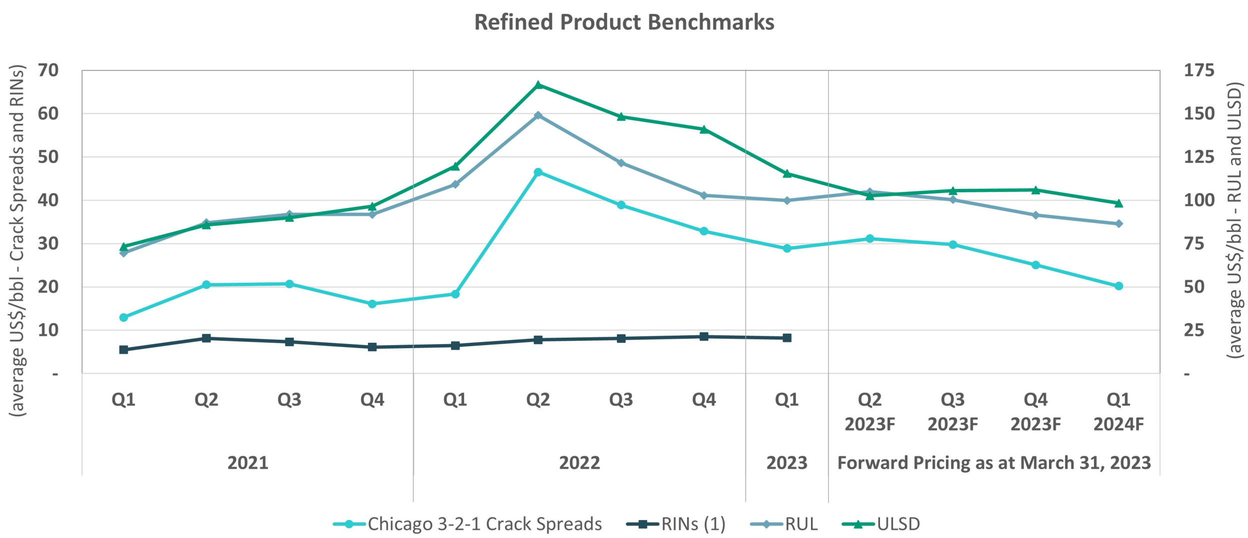
RUL and ULSD benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 market crack spread. The 3-2-1 market crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded 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 Borger Refinery.

Refined product prices declined in the first quarter compared with the fourth and first quarters of 2022. The strength in market crack spreads and refined product prices has been driven by growing demand, refinery rationalization since the beginning of the COVID-19 pandemic, unplanned maintenance leading to high refinery utilization globally, combined with low global inventories of refined products. RINs costs increased from the first quarter of 2022 and declined slightly with the fourth quarter of 2022. RINs costs remain high as a result of a tight biofuel market, rising feedstock prices and uncertainty around policies that drive RINs demand.

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 realized crack spreads are affected by many other factors such as the variety of crude oil feedstock; refinery configuration and product output; where feedstocks are acquired and the time lag between the purchase and delivery of crude oil feedstock; and the cost of feedstock, which 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 natural gas prices decreased compared with the first and fourth quarters of 2022, due to mild winter conditions weighing on U.S. domestic demand coupled with record high natural gas production. Average AECO prices also declined along with NYMEX prices, but not to the same extent due to stronger Canadian domestic demand. The price received for our Asia Pacific natural gas production is largely based on long-term contracts.

Foreign Exchange Benchmarks

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

In the first quarter of 2023, the Canadian dollar on average weakened relative to the U.S. dollar compared with the first quarter of 2022, positively impacting our reported revenues quarter-over-quarter. The Canadian dollar was flat relative to the U.S. dollar as at March 31, 2023, compared with December 31, 2022, resulting in minimal unrealized foreign exchange impacts on the translation of our U.S. dollar debt into Canadian dollars.

A portion of our long-term sales contracts in the Asia Pacific are priced in RMB. An increase in the value of the Canadian dollar relative to the RMB will decrease the revenues received in Canadian dollars from the sale of natural gas commodities in the region. In the first quarter of 2023, the Canadian dollar on average was relatively flat with RMB compared with the first quarter of 2022, resulting in minimal impact on our revenues quarter-over-quarter.

Interest Rate Benchmarks

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

As at March 31, 2023, the Bank of Canada's Policy Interest Rate was 4.50 percent, an increase of 0.25 percent from December 31, 2022, due to concerns over inflation.

OUTLOOK

COMMODITY PRICE OUTLOOK

Crude oil prices have declined gradually since the second quarter of 2022 due to demand concerns amid a weakening macroeconomic environment. The geopolitical premium associated with Russian supply uncertainty also faded in the back half of 2022 as Russian exports of crude oil and refined products remained resilient. 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 shifting global trade patterns. OPEC+ policy will continue to be a key driver of crude oil prices and the April 2, 2023, announcement of a cut to the group's production quotas is supportive of pricing.

Overall, we expect the general outlook for crude oil and refined product prices will be volatile and impacted by the duration and severity of the ongoing Russian invasion of Ukraine, the extent to which Russian exports are reduced by sanctions, the timing and ability of producers and governments to replace reduced supply, the refilling or release of SPRs and OPEC+ policy. In addition, potential incremental COVID-19 outbreaks and variants, weakening global economic activity, inflation and rising interest rates, 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 that the WTI-WCS 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 anticipated start-up of the Trans Mountain pipeline expansion in 2024 to have a narrowing impact on WTI-WCS differentials.
- We expect market crack spreads will remain volatile. Economic effects of the ongoing Russian invasion of Ukraine and central bank policies could impact demand. Refining 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 due to strong supply and ample 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 crude oil prices, 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, and emerging macro-economic factors.

Most of our upstream crude oil and downstream refined products production are exposed to movements in the WTI crude oil price. Our physically integrated upstream and downstream operations help us to mitigate the impact of commodity price volatility. Natural gas and NGLs production associated with our Conventional operations provide economic integration for the fuel, solvent and blending requirements at our Oil Sands operations. Crude oil production in our upstream assets is used as feedstock by our downstream operations, and condensate extracted from our blended crude oil production is sold back to our Oil Sands operations.

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

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

- Transportation commitments and arrangements – using our existing firm service commitments for takeaway capacity and supporting transportation projects that move crude oil from our production areas to consuming markets, including tidewater markets.
- Integration – heavy oil refining capacity allows us to capture value from both the WTI-WCS differential for Canadian crude oil as well as from spreads on refined products.
- Dynamic storage – our ability to use the significant storage capacity in our oil sands reservoirs provides us flexibility on timing of production and sales of our inventory. We will continue to manage our production rates in response to pipeline capacity constraints, voluntary and mandated production curtailments and crude oil price differentials.
- Traditional crude oil storage tanks in various geographic locations.

REPORTABLE SEGMENTS

UPSTREAM

Oil Sands

In the first quarter of 2023, we:

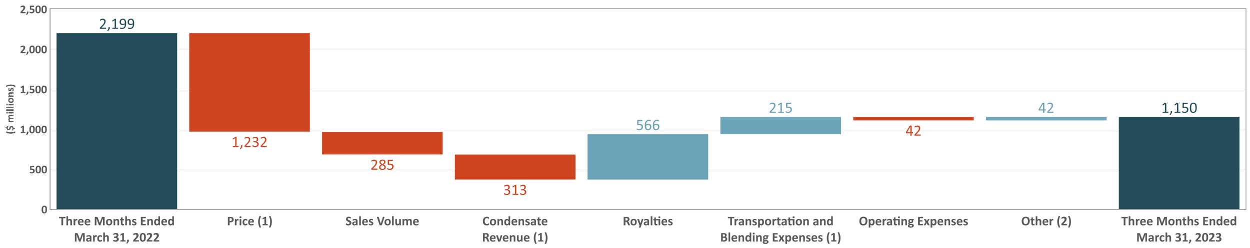
- Delivered safe operations.
- Produced 587.5 thousand barrels of crude oil per day.
- Generated Operating Margin of $1.2 billion, a decrease of $1.0 billion compared with 2022 primarily due to lower average realized sales prices.
- Invested capital of $635 million primarily for sustaining activities at Christina Lake, Foster Creek, the Lloydminster thermal assets and Sunrise, and the drilling of stratigraphic test wells as part of our integrated winter program.
- Achieved a Netback of $22.55 per BOE.

Financial Results

	Three Months Ended March 31,	
($ millions)	**2023**	2022
Revenues		
Gross Sales	**5,911**	9,218
Less: Royalties	**516**	1,082
	5,395	8,136
Expenses		
Purchased Product	**559**	1,212
Transportation and Blending	**2,941**	3,156
Operating	**737**	702
Realized (Gain) Loss on Risk Management	**8**	867
Operating Margin	**1,150**	2,199
Unrealized (Gain) Loss on Risk Management	**(34)**	266
Depreciation, Depletion and Amortization	**715**	635
Exploration Expense	**2**	1
Segment Income (Loss)	**467**	1,297

Operating Margin Variance

Three Months Ended March 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) Other includes third-party sourced volumes, construction and other activities not attributable to the production of crude oil, NGLs or natural gas.

Operating Results

	Three Months Ended March 31,	
	2023	2022
Total Sales Volumes (MBOE/d)	**577.0**	609.9
Total Realized Price (1) ($/BOE)	**55.60**	95.90
Crude Oil Production by Asset (Mbbls/d)		
Foster Creek	**190.0**	197.9
Christina Lake	**237.2**	254.1
Sunrise (2)	**44.5**	24.1
Lloydminster Thermal	**99.0**	96.3
Lloydminster Conventional Heavy Oil	**16.8**	16.2
Tucker (3)	**—**	6.4
Total Crude Oil Production (4) (Mbbls/d)	**587.5**	595.0
Natural Gas (5) (MMcf/d)	**12.0**	12.8
Total Production (MBOE/d)	**589.5**	597.0
Effective Royalty Rate (percent)	**21.4**	22.3
Transportation and Blending Expense (1) ($/BOE)	**9.07**	7.23
Operating Expense (1) ($/BOE)	**14.04**	12.51
Per Unit DD&A (1) ($/BOE)	**12.72**	11.80

(1) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(2) On August 31, 2022, we acquired the remaining 50 percent interest in Sunrise from BP Canada.
(3) The Tucker asset was sold on January 31, 2022.
(4) Oil Sands production is primarily bitumen, except for Lloydminster conventional heavy oil, which is heavy crude oil.
(5) Conventional natural gas product type.

Revenues

Price

Our heavy oil and bitumen production must be blended with condensate to reduce its viscosity to transport it to market through pipelines. Our realized bitumen sales price does not include the sale of condensate; however, it is influenced by the price of condensate. As the cost of condensate increases relative to the price of blended crude oil, our realized heavy oil and bitumen sales price decreases. In the first quarter of 2023, condensate benchmark pricing was at a US$28.51 per barrel premium to WCS at Hardisty, which widened slightly compared with the fourth quarter of 2022 and widened significantly from US$16.33 per barrel in the first quarter of 2022. The increases had a negative impact on our realized bitumen sales price. Up to three months may lapse from when we purchase condensate to when we sell our blended production.

Our realized sales price averaged $55.60 per BOE in the first quarter of 2023 compared with $95.90 per BOE in 2022 due to lower WTI benchmark prices and wider WTI-WCS differentials. The WTI-WSC differential at Hardisty widened significantly to US$24.77 per barrel compared with US$14.53 per barrel in the first quarter of 2022. To improve our realized sales price, we sold approximately 25 percent (2022 – 25 percent) of our crude oil volumes at U.S. destinations.

For the three months ended March 31, 2023, gross sales included $498 million (2022 – $1.1 billion), from third-party sourced volumes which are not included in our realized price or our Netbacks. Refer to the Specified Financial Measures Advisory of this MD&A for more detail.

For the three months ended March 31, 2023, gross sales included $80 million (2022 – $52 million), relating to construction, transportation and blending activities. These amounts are not included in our realized price or our Netbacks. Refer to the Specified Financial Measures Advisory of this MD&A for more detail.

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

In the first three months of 2023, we incurred realized risk management losses of $8 million (2022 – $867 million) due to the settlement of benchmark prices rising above our risk management contract prices. The change is due to a rising commodity price environment in the first quarter of 2022 and management's decision to liquidate our WTI positions related to crude oil sales price risk management in the second quarter of 2022. In the first three months of 2023, we recorded unrealized risk management gains of $34 million (2022 – losses of $266 million) on our crude oil and condensate financial instruments primarily due to changes in forward benchmark pricing relative to our risk management contract prices that related to future periods.

Production Volumes

Oil Sands crude oil production decreased slightly to 587.5 thousand barrels per day in the first quarter of 2023 compared with 595.0 thousand barrels per day in 2022.

Production at Foster Creek decreased 7.9 thousand barrels per day to 190.0 thousand barrels per day in 2023 compared with 2022. Production at Christina Lake decreased 16.9 thousand barrels per day to 237.2 thousand barrels per day in 2023 compared with 2022. Production at Foster Creek and Christina Lake was lower as we prepare for the start-up of new well pads. Foster Creek and Christina Lake each have three additional well pads expected to be brought online in the last half of 2023.

The Sunrise Acquisition was completed on August 31, 2022. Production at Sunrise increased 20.4 thousand barrels per day in the first quarter of 2023 compared with 2022. The increase in production related to the acquisition was partially offset by wells taken offline in preparation for a 2023 redevelopment program.

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

Lloydminster conventional heavy oil production increased in 2023 compared with 2022.

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.

Effective royalty rates decreased compared with 2022 primarily due to lower realized pricing and lower Alberta oil sands sliding scale royalty rates, partially offset by a higher Christina Lake effective royalty rate related to annual adjustments on the end-of-period filings. For the three months ended March 31, 2023, royalties were $516 million (2022 – $1.1 billion).

Expenses

Transportation and Blending

In the first quarter of 2023, blending costs decreased $308 million to $2.5 billion compared with 2022. The decline was largely due to lower condensate prices and volumes.

Transportation costs increased $93 million to $490 million in the first three months of 2023 compared with 2022. The increases were primarily due to higher costs as discussed below, partially offset by lower sales volumes.

Per-unit Transportation Expenses

Transportation costs were $9.07 per BOE in the first quarter of 2023 compared with $7.23 per BOE in 2022.

At Foster Creek, per-unit transportation costs increased 36 percent to $13.45 per barrel in 2023 compared with 2022. The increase was mainly due to lower sales volumes. In addition, in 2023 we shipped 49 percent of our volumes from Foster Creek to U.S. destinations compared with 38 percent in 2022.

At Christina Lake, transportation costs were $7.70 per barrel in 2023, an increase from $6.37 per barrel in 2022, primarily due to lower sales volumes and increased tariff rates. In 2023 we shipped 15 percent (2022 – 17 percent) of our volumes from Christina Lake to U.S. destinations.

At Sunrise, transportation costs were $12.67 per barrel in 2023, a decrease from $13.15 per barrel in 2022, as we shipped 46 percent (2022 – 67 percent) of our total volumes to the U.S. The decrease is partially offset by lower gross sales volumes and higher tariff rates in 2023.

At our Other Oil Sands assets, transportation costs in 2023 were $3.74 per barrel, consistent with $3.51 per barrel in 2022.

Operating

Primary drivers of our operating expenses in the first quarter of 2023 were fuel, workforce, chemicals, and repairs and maintenance. Total operating expenses increased due to higher repairs and maintenance, workforce, fluid and waste handling, and electricity costs. The increases were partially offset by lower fuel costs as a result of AECO benchmark prices decreasing five percent from the first quarter of 2022.

Unit Operating Expenses [1]

	Three Months Ended March 31,		
($/BOE)	**2023**	**Percent Change**	2022
Foster Creek			
Fuel	**5.11**	**8**	4.71
Non-Fuel	**7.88**	**22**	6.48
Total	**12.99**	**16**	11.19
Christina Lake			
Fuel	**3.75**	**(17)**	4.51
Non-Fuel	**5.36**	**14**	4.71
Total	**9.11**	**(1)**	9.22
Sunrise			
Fuel	**6.66**	**2**	6.53
Non-Fuel	**15.37**	**48**	10.42
Total	**22.03**	**30**	16.95
Other Oil Sands [2]			
Fuel	**5.93**	**(15)**	7.00
Non-Fuel	**17.15**	**26**	13.63
Total	**23.08**	**12**	20.63
Total	**14.04**	**12**	12.51

(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 fuel prices decreased overall due to lower natural gas prices as discussed above. Per-unit fuel prices are also impacted by the timing and value of sales out of inventory. In a decreasing fuel price environment, the value of inventory is typically higher than when the sale occurs, resulting in higher fuel operating costs.

Foster Creek per-unit non-fuel costs increased 22 percent to $7.88 per barrel compared with 2022, due to lower sales volumes, combined with higher repairs and maintenance, chemical and workforce costs.

Christina Lake per unit non-fuel costs increased 14 percent to $5.36 per barrel compared with 2022, due to lower sales volumes, combined with higher workforce costs.

Sunrise per unit non-fuel costs increased 48 percent to $15.37 per barrel compared with 2022, driven by lower gross sales volumes in 2023 and higher workforce, electricity, and water hauling and trucking costs. Gross sales volumes in 2023 were 39.8 thousand barrels per day compared with 50.6 thousand barrels per day in 2022.

Per-unit non-fuel costs at our Other Oil Sands assets increased 26 percent to $17.15 per barrel compared with 2022, primarily due to higher repairs and maintenance and workover activity combined with lower sales volumes.

Netbacks

	Three Months Ended March 31,	
($/BOE)	**2023**	2022
Sales Price (1)	**55.60**	95.90
Royalties (1)	**9.94**	19.72
Transportation (1)	**9.07**	7.23
Operating Expenses (1)	**14.04**	12.51
Netback (2)	**22.55**	56.44

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

DD&A

In the three months ended March 31, 2023, DD&A was $715 million, compared with $635 million in 2022. The average depletion rate for the three months ended March 31, 2023, was $12.72 per BOE, compared with $11.80 per BOE in 2022.

Conventional

In the first quarter of 2023, we:

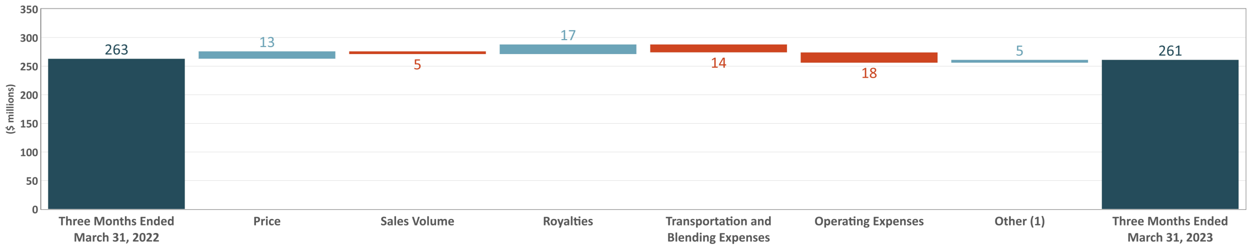
- Delivered safe and reliable operations.
- Generated Operating Margin of $261 million, a slight decrease compared with 2022.
- Invested capital of $141 million focused on drilling, completion and tie-in activities, and infrastructure projects to support multi-year development.
- Achieved a Netback of $22.08 per BOE.

Financial Results

	Three Months Ended March 31,	
($ millions)	**2023**	2022
Revenues		
Gross Sales	**1,031**	1,112
Less: Royalties	**54**	71
	977	1,041
Expenses		
Purchased Product	**510**	606
Transportation and Blending	**48**	34
Operating	**150**	134
Realized (Gain) Loss on Risk Management	**8**	4
Operating Margin	**261**	263
Unrealized (Gain) Loss on Risk Management	**(20)**	—
Depreciation, Depletion and Amortization	**95**	80
Segment Income (Loss)	**186**	183

Operating Margin Variance

Three Months Ended March 31, 2023



(1) Reflects Operating Margin from processing facilities.

Operating Results

	Three Months Ended March 31,	
	2023	2022
Total Sales Volumes (MBOE/d)	**123.9**	125.2
Total Realized Price [(1)] ($/BOE)	**44.30**	42.84
Light Crude Oil ($/bbl)	**102.80**	112.67
NGLs ($/bbl)	**48.05**	55.39
Conventional Natural Gas ($/Mcf)	**6.58**	5.55
Production by Product		
Light Crude Oil (Mbbls/d)	**6.4**	8.2
NGLs (Mbbls/d)	**22.0**	24.5
Conventional Natural Gas (MMcf/d)	**572.9**	555.0
Total Production (MBOE/d)	**123.9**	125.2
Conventional Natural Gas Production (percentage of total)	**77**	74
Crude Oil and NGLs Production (percentage of total)	**23**	26
Effective Royalty Rate (percent)	**17.3**	15.9
Transportation Costs [(1)] ($/BOE)	**4.34**	3.18
Operating Expense [(1)] ($/BOE)	**13.07**	11.33
Per Unit DD&A [(1)] ($/BOE)	**8.41**	8.16

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

Revenues

Price

Our total realized sales price was consistent compared with 2022 due to higher realized natural gas prices, offset by decreased realized crude oil and NGL prices. AECO benchmark natural gas prices decreased five percent from 2022 and our total realized natural gas sales price increased 19 percent from 2022, as we realized significantly higher prices on volumes sold at U.S. destinations. Our realized oil and NGL prices decreased due to lower benchmark pricing.

For the three months ended March 31, 2023, gross sales included $510 million (2022 – $606 million), relating to third-party sourced volumes, which are not included in our realized prices or our Netbacks. Refer to the Specified Financial Measures Advisory of this MD&A for more detail.

For the three months ended March 31, 2023, gross sales included amounts relating to processing and transportation activities undertaken for third-parties of $27 million (2022 – $24 million), which are not included in our realized prices or our Netbacks. Refer to the Specified Financial Measures Advisory of this MD&A for more detail.

Production Volumes

Production volumes were flat compared with 2022. We brought 16 net new wells online during the quarter (2022 – 20 net new wells). These positive impacts were offset by natural declines and the sale of the Wembley asset on February 28, 2022.

Royalties

The Conventional assets are subject to royalty regimes in Alberta and British Columbia. Total royalties decreased from 2022 due to lower royalty rates and increased gas cost allowance ("GCA") deductions. In Alberta, natural gas wells benefit from the GCA which reduces royalties to account for capital and operating costs incurred to process and transport the Crown's portion of natural gas production. Effective royalty rates increased from 2022 due to lower sales volumes.

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 $14 million to $48 million compared with 2022. Per-unit transportation costs averaged $4.34 per BOE in 2023, compared with $3.18 per BOE in 2022.

Operating

Primary drivers of our operating expenses in the first quarter of 2023 were repairs and maintenance, workforce, property taxes and lease costs, and electricity. Operating expenses per BOE increased $1.74 per BOE to $13.07 per BOE in the first quarter of 2023 compared with 2022, primarily due to higher workforce, repairs and maintenance, and workover costs. Total operating expenses increased $16 million to $150 million in 2023 compared with 2022.

Netbacks

	Three Months Ended March 31,	
($/BOE)	**2023**	2022
Sales Price (1)	**44.30**	42.84
Royalties (1)	**4.81**	6.29
Transportation and Blending (1)	**4.34**	3.18
Operating Expenses (1)	**13.07**	11.33
Netback (2)	**22.08**	22.04

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

DD&A

For the three months ended March 31, 2023, total Conventional DD&A was $95 million (2022 – $80 million). The average depletion rate for the first quarter of 2023 was $8.41 per BOE (2022 – $8.16 per BOE).

Offshore

In the first quarter of 2023, we:

- Delivered safe operations.
- Generated Operating Margin of $300 million, a decrease of $158 million compared with 2022, largely due to lower sales volumes from our China operations and declines in benchmark pricing. In addition, operating expenses from our Atlantic operations increased leading up to the start of major construction at the West White Rose project. Major construction began in late March.
- Earned a Netback of $57.06 per BOE.
- Invested capital of $100 million mainly for the West White Rose project and Terra Nova ALE project in the Atlantic region.

On May 31, 2022, Cenovus and its partners announced the restart of the West White Rose project resulting in a 12.5 percent reduction of our working interest in the White Rose field and satellite extensions. The West White Rose project is anticipated to have peak production of 80 thousand barrels per day (45 thousand barrels per day, net to Cenovus) with first oil expected in the first half of 2026. Total capital required to achieve first oil is expected to be approximately $2.0 billion to $2.3 billion net to Cenovus. At March 31, 2023, the project was around 65 percent complete. Since our decision to restart the project, we have invested approximately $155 million.

At Terra Nova, preparation and maintenance activities continue on the floating production, storage and offloading unit ("FPSO") and we are evaluating the schedule.

At our equity-accounted assets in Indonesia, we drilled and completed the third of three planned development wells at the MAC field. We expect first gas production from the field in the third quarter of 2023.

In China, we finalized an agreement in the second quarter of 2022 that increases gas sales at Liuhua 29-1 for the duration of the contract. This partially offsets some of the reduction in contracted natural gas sales from Liwan 3-1, due to the conclusion of an amendment in the second quarter of 2022 that temporarily increased sales volumes. Starting in 2023, contracted gas sales volumes decreased further as part of the Liwan 3-1 contract.

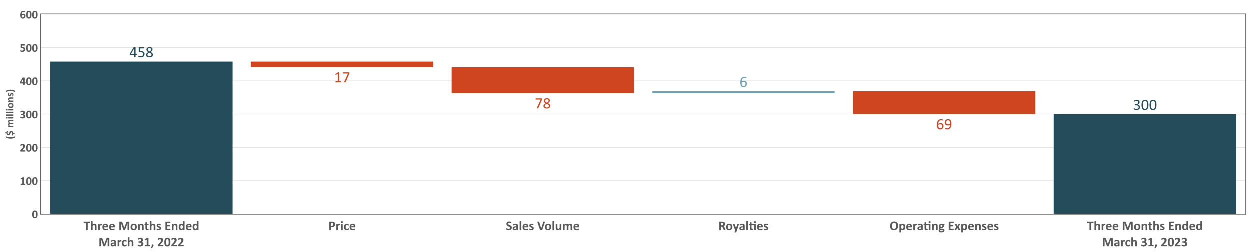
Financial Results

	Three Months Ended March 31,					
	2023			2022		
($ millions)	**Asia Pacific**	**Atlantic**	**Offshore**	Asia Pacific	Atlantic	Offshore
Revenues						
Gross Sales	**324**	**149**	**473**	395	172	567
Less: Royalties	**18**	**8**	**26**	22	10	32
	306	**141**	**447**	373	162	535
Expenses						
Transportation and Blending	**—**	**5**	**5**	—	4	4
Operating	**25**	**117**	**142**	27	46	73
Operating Margin (1)	**281**	**19**	**300**	346	112	458
Depreciation, Depletion and Amortization			**128**			150
Exploration Expense			**2**			15
(Income) Loss from Equity-Accounted Affiliates			**(6)**			(4)
Segment Income (Loss)			**176**			297

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

Operating Margin Variance

Three Months Ended March 31, 2023



Operating Results

	Three Months Ended March 31,	
	2023	2022
Sales Volumes		
Atlantic (Mbbls/d)	**15.7**	14.6
Asia Pacific (MBOE/d)		
China	**43.0**	53.6
Indonesia (1)	**13.7**	9.1
Asia Pacific Total	**56.7**	62.7
Total Sales Volumes (MBOE/d)	**72.4**	77.3
Total Realized Price (2) ($/BOE)	**83.64**	90.44
Atlantic - Light Crude Oil ($/bbl)	**104.98**	130.87
Asia Pacific (1) ($/BOE)	**77.71**	81.04
NGLs ($/bbl)	**96.45**	110.30
Conventional Natural Gas ($/Mcf)	**12.17**	12.22
Production by Product		
Atlantic - Light Crude Oil (Mbbls/d)	**8.9**	13.7
Asia Pacific (1)		
NGLs (Mbbls/d)	**11.4**	13.1
Conventional Natural Gas (MMcf/d)	**272.1**	297.5
Asia Pacific Total (MBOE/d)	**56.7**	62.7
Total Production (MBOE/d)	**65.6**	76.4
Effective Royalty Rate (percent)		
Atlantic	**5.3**	6.1
Asia Pacific (1)	**10.2**	10.8
Operating Expense (2) ($/BOE)	**18.50**	11.63
Atlantic	**59.73**	36.06
Asia Pacific (1)	**7.05**	5.95
Per Unit DD&A (2) ($/BOE)	**31.09**	29.86

(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 the first quarter of 2023 compared with 2022, primarily due to lower Brent benchmark pricing.

Production Volumes

Atlantic production decreased 4.8 thousand barrels per day to 8.9 thousand barrels per day compared with 2022, due to the decrease in Cenovus's working interest at the White Rose field and satellite extensions in the second quarter of 2022. In addition, production was impacted by turnaround work on the SeaRose FPSO, originally planned for later in the year that was advanced to the first quarter. Production resumed in late April. Light crude oil from production at 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 slightly in the first quarter of 2023 compared with 2022, due to changes to contracts at Liwan 3-1 and Liuhua 29-1 in the second quarter of 2022, resulting 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.

Royalties

In the first quarter of 2023, Atlantic royalties were $8 million (2022 – $10 million).

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 first quarter of 2023 was 10.2 percent (2022 – 10.8 percent).

Expenses

Operating

Primary drivers of our Atlantic operating expenses in the first quarter of 2023 were repairs and maintenance, vessel and helicopter costs, and workforce. Total operating expenses increased mainly due to costs related to the ramp up of the West White Rose project leading up to the start of major construction in late March. In addition, continued preparations and maintenance activities for the Terra Nova FPSO's return to operation increased operating expenses. The increase was partially offset by the working interest restructuring on the White Rose fields in the second quarter of 2022. Per-unit operating expenses increased due to increased costs at Terra Nova discussed above.

Primary drivers of our Asia Pacific operating expenses in the first quarter of 2023 were repairs and maintenance, insurance and workforce. Total operating expenses were relatively consistent with 2022. Per-unit operating expenses increased $1.10 per BOE to $7.05 per BOE in the first quarter of 2023 mainly due to lower sales volumes and the MBH and MDA fields in Indonesia coming online in the fourth quarter of 2022.

Transportation

Transportation in the Atlantic region remained consistent compared with 2022 and includes the cost of transporting crude oil from the SeaRose FPSO unit to onshore via tankers, as well as storage costs.

Netbacks

	Three Months Ended March 31, 2023			
($/BOE, except where indicated)	**China**	**Indonesia** [1]	**Atlantic** ($/bbl)	**Total Offshore**
Sales Price [2]	**83.50**	**59.46**	**104.98**	**83.64**
Royalties [2]	**4.60**	**18.31**	**5.53**	**7.39**
Transportation and Blending [2]	**—**	**—**	**3.16**	**0.69**
Operating Expenses [2]	**5.58**	**11.69**	**59.73**	**18.50**
Netback [3]	**73.32**	**29.46**	**36.56**	**57.06**

	Three Months Ended March 31, 2022			
($/BOE, except where indicated)	China	Indonesia [1]	Atlantic ($/bbl)	Total Offshore
Sales Price [2]	82.09	74.82	130.87	90.44
Royalties [2]	4.43	34.23	7.81	8.58
Transportation and Blending [2]	—	—	3.51	0.66
Operating Expenses [2]	4.66	13.51	36.06	11.63
Netback [3]	73.00	27.08	83.49	69.57

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

DD&A

In the first quarter of 2023, total Offshore DD&A was $128 million (2022 – $150 million). The average depletion rate in the first quarter of 2023 was $31.09 per BOE, (2022 – $29.86 per BOE).

DOWNSTREAM

Canadian Manufacturing

In the first quarter of 2023, we:

- Delivered safe operations.
- Achieved crude utilization of 99 percent at the Lloydminster Refinery and averaged crude utilization of 86 percent at the Upgrader.
- Generated Operating Margin of $263 million, an increase of $142 million compared with 2022, primarily due to a higher upgrading differential, and higher margins on asphalt and industrial products.

Financial Results

	Three Months Ended March 31,	
($ millions)	**2023**	2022
Revenues	**1,508**	1,607
Purchased Product	**1,093**	1,335
Gross Margin [1]	**415**	272
Expenses		
Operating	**152**	151
Operating Margin	**263**	121
Depreciation, Depletion and Amortization	**43**	50
Segment Income (Loss)	**220**	71

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

Select Operating Results

	Three Months Ended March 31,	
	2023	2022
Heavy Crude Oil Unit Throughput Capacity (Mbbls/d)	**110.5**	110.5
Lloydminster Upgrader	**81.5**	81.5
Lloydminster Refinery	**29.0**	29.0
Heavy Crude Oil Unit Throughput (Mbbls/d)	**98.7**	98.1
Lloydminster Upgrader	**70.0**	70.7
Lloydminster Refinery	**28.7**	27.4
Crude Utilization [1] (percent)	**89**	89
Total Production (Mbbls/d)	**106.4**	104.3
Refined Products	**101.3**	99.4
Ethanol	**5.1**	4.9
Upgrading Differential [2] ($/bbl)	**41.75**	20.50
Refining Margin [3] ($/bbl)	**43.30**	24.28
Lloydminster Upgrader	**48.53**	26.98
Lloydminster Refinery	**30.53**	17.33
Unit Operating Expense [4] ($/bbl)	**12.46**	10.99
Rail		
Volumes Loaded [5] (Mbbls/d)	**2.2**	3.0

(1) Based on crude oil unit throughput volumes and results of operations at the Upgrader and Lloydminster Refinery.
(2) Based on benchmark price differential between heavy oil feedstock and synthetic crude.
(3) Contains a Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A. Revenues from the Upgrader and commercial fuels business for the three months ended March 31, 2023, were $1.2 billion (2022 – $756 million from the Upgrader). Revenues from the Lloydminster Refinery for the three months ended March 31, 2023, were $188 million (2022 – $186 million).
(4) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.
(5) Volumes transported outside of Alberta, Canada.

Throughput at the Upgrader decreased marginally from the first quarter of 2022 to 70.0 thousand barrels per day. The Upgrader returned to full rates by the middle of January 2023 after being impacted by cold weather and operational outages in the fourth quarter of 2022. Throughput at the Upgrader was impacted by maintenance activities in the first quarter of 2022.

Throughput at the Lloydminster Refinery increased slightly from the first quarter of 2022 to 28.7 thousand barrels per day. The refinery operated at or near capacity throughout the first quarter of 2023 and 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 increase during paving season, which typically runs from May through October each year.

The Upgrader sources crude oil feedstock primarily from our Lloydminster thermal production. The Lloydminster Refinery sources crude oil feedstock from our Lloydminster thermal and Lloydminster conventional heavy oil production.

In the first quarter of 2023, revenues decreased by $99 million to $1.5 billion, mainly due to the disposition of our retail network in the third quarter of 2022.

Gross margin increased $143 million in the first quarter of 2023 compared with 2022, as the upgrading differential doubled, combined with higher margins on asphalt and industrial product sales. The increase was partially offset by the disposition of the retail fuels business in the third quarter of 2022.

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

Operating Expenses

Primary drivers of operating expenses in the first quarter of 2023 were repairs and maintenance, workforce and energy costs. Total operating costs were consistent compared with 2022, due to higher repairs and maintenance costs at the Upgrader, offset by lower costs related to the retail assets divested in the third quarter of 2022.

Per-unit operating expenses increased primarily due to higher repairs and maintenance costs at the Upgrader. Per-unit operating costs apply only to operating costs and throughput at the Upgrader and Lloydminster Refinery.

DD&A

In the first quarter of 2023, Canadian Manufacturing DD&A was $43 million, compared with $50 million in 2022.

U.S. Manufacturing

In the first quarter of 2023, we:

- Delivered safe operations.
- Generated Operating Margin of $128 million, a decrease of $295 million compared with 2022, largely due to a lower per barrel refining margin, lower crude oil throughput and refined product output, and higher operating expenses.
- Achieved crude utilization of 94 percent at the Lima Refinery.
- Averaged crude utilization of 67 percent and crude oil throughput of 359.2 thousand barrels per day across all U.S. Manufacturing assets. Crude utilization excludes the throughput and capacity of the Superior Refinery.
- Commenced a planned turnaround at the Borger Refinery and the first phase of a planned turnaround at the Wood River Refinery, which were completed in April.
- Started circulating hydrocarbons at the Superior Refinery in February and introduced crude oil in mid-March. The refinery is ramping up through the second quarter.
- Invested capital of $194 million focused primarily on the Superior Refinery rebuild, and refining reliability initiatives at the Wood River and Borger refineries.

On February 28, 2023, we closed the purchase of the remaining 50 percent interest in the Toledo Refinery from BP for cash of US$368 million, including working capital. The Toledo Acquisition provides us with full ownership and operatorship and further integrates our heavy oil production and refining capabilities. The transaction gives us an additional 80.0 thousand barrels per day of downstream throughput capacity, including 45.0 thousand barrels per day of heavy oil refining capacity.

Financial Results

($ millions)	Three Months Ended March 31, 2023	2022
Revenues	**5,860**	6,509
Purchased Product	**5,129**	5,482
Gross Margin [1]	**731**	1,027
Expenses		
Operating	**602**	494
Realized (Gain) Loss on Risk Management	**1**	110
Operating Margin	**128**	423
Unrealized (Gain) Loss on Risk Management	**(6)**	27
Depreciation, Depletion and Amortization	**103**	85
Segment Income (Loss)	**31**	311

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

Select Operating Results

	Three Months Ended March 31, 2023	2022
Crude Oil Unit Throughput Capacity [1] (Mbbls/d)	**635.2**	502.5
Lima Refinery [2]	**178.7**	175.0
Superior Refinery	**49.0**	—
Toledo Refinery [3]	**160.0**	80.0
Wood River and Borger Refineries [4]	**247.5**	247.5
Crude Oil Unit Throughput (Mbbls/d)	**359.2**	403.7
Lima Refinery	**167.2**	136.1
Superior Refinery	**0.2**	—
Toledo Refinery [3]	**—**	72.1
Wood River and Borger Refineries [4]	**191.8**	195.5
Crude Oil Unit Throughput by Product (Mbbls/d)		
Heavy Crude Oil	**114.7**	153.8
Light and Medium Crude Oil	**244.5**	249.9
Crude Utilization [5] (percent)	**67**	80
Production (Mbbls/d)	**379.0**	430.6
Refining Margin [6] [7] ($/bbl)	**22.62**	28.26
Unit Operating Expense [7] [8] ($/bbl)	**18.63**	13.59

(1) Based on crude oil name plate capacity.
(2) The name plate capacity at the Lima Refinery increased effective January 1, 2023.
(3) Cenovus acquired the remaining 50 percent interest in the Toledo Refinery from BP on February 28, 2023.
(4) Represents Cenovus's 50 percent interest in the non-operated Wood River and Borger refinery operations.
(5) The Superior Refinery's crude oil throughput and crude oil throughput capacity are not included in the crude utilization calculation. The Toledo Refinery's crude utilization includes a weighted average crude oil capacity with full ownership acquired on February 28, 2023.
(6) Contains a Non-GAAP financial measure. See the Specified Financial Measures Advisory of this MD&A.
(7) Based on crude oil throughput volumes and operating results at Wood River, Borger, Lima, Toledo and Superior refineries.
(8) Specified financial measure. See the Specified Financial Measures Advisory of this MD&A.

In the first quarter of 2023, total crude utilization across the segment was 67 percent (2022 – 80 percent):

- The Lima Refinery returned to normal rates in early January 2023 following the impacts of winter storm Elliott events in December 2022. The refinery performed very well during the quarter, achieving crude utilization of 94 percent (2022 – 78 percent).
- The Toledo Refinery remained shut down in the first quarter of 2023. Crude utilization in the first quarter of 2022 was 90 percent. Repairs to the damaged units are ongoing. The refinery partially restarted in April 2023 and is ramping up through the second quarter.
- In December 2022, an incident occurred at the Wood River Refinery that reduced throughput. Crude utilization has steadily increased since the first week of January with a main component for jet fuel production returning to service in mid-March. In late February, the first phase of a planned turnaround commenced at the refinery which was completed by early April. The second phase, which will also impact throughput, started in mid-April and is expected to be completed in May.
- The Borger Refinery had unplanned operational outages in the fourth quarter of 2022 and returned to full rates in January 2023. Additional minor unplanned outages occurred in the first quarter and a planned turnaround commenced at the refinery at the end of March which was completed by late April.
- Combined crude utilization for the Wood River and Borger refineries was 77 percent (2022 – 79 percent).

At the Superior Refinery, we started circulating hydrocarbons in February and introduced crude oil in mid-March 2023. The refinery is ramping up through the second quarter.

Revenues and Gross Margin

Market crack spreads do not precisely mirror the configuration and product output of our refineries; however, they are used as a general market indicator. 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.

Revenues decreased $649 million to $5.9 billion in the first quarter of 2023 compared with 2022. The decrease was primarily due to lower refined product output and lower refined product pricing.

Gross margin decreased $296 million to $731 million in the first quarter of 2023 compared with 2022, primarily due to higher cost of feedstock processed from inventory, lower refined product pricing and lower production. As a result of an incident at the Wood River Refinery in December, the refinery was unable to produce jet fuel until mid-March. In the quarter, jet fuel purchased to fulfill supply contracts negatively impacted gross margin. In the first quarter of 2023, RINs costs were $281 million (2022 – $233 million). RINs prices averaged US$8.20 per barrel in the first three months of 2023, compared with US$6.44 per barrel in 2022.

In the three months ended March 31, 2023, we incurred realized risk management losses of $1 million (2022 – $110 million). The decrease is due to a rising commodity price environment in the first quarter of 2022. In the first quarter of 2023, we recorded unrealized risk management gains of $6 million (2022 – losses of $27 million) on our crude oil and refined products financial instruments.

Operating Expenses

Primary drivers of operating expenses in the first quarter of 2023 were repairs and maintenance, workforce, and electricity costs.

Operating expenses increased $108 million to $602 million in the first three months of 2023, compared with 2022. The increase was mainly due to:

- Increased maintenance and preparation work at the Superior Refinery.
- Acquiring full ownership of the Toledo Refinery on February 28, 2023.
- Repairs and maintenance costs related to the planned turnarounds at the Wood River and Borger refineries, and operational issues at the Wood River Refinery as discussed above.
- Increased workforce and chemical costs.
- Higher electricity pricing.

The increase was partially offset by costs associated with 2022 turnaround activity at the Wood River and Toledo refineries.

In the first quarter of 2023, per-unit operating expenses increased $5.04 per barrel of crude throughput to $18.63 per barrel compared with 2022. The increase was primarily due to the same factors as discussed above, combined with lower crude throughput. Superior Refinery operating expenses are included in per-unit operating expenses.

DD&A

U.S. Manufacturing DD&A was $103 million in the first quarter of 2023, compared with $85 million in 2022.

CORPORATE AND ELIMINATIONS

In the first quarter of 2023, our corporate risk management activities resulted in:

- Realized risk management losses of $7 million (2022 – gains of $7 million) related to foreign exchange risk management contracts.
- Unrealized risk management losses of $30 million (2022 – $18 million) related to renewable power contracts and foreign exchange risk management contracts.

Financial Results

($ millions)	Three Months Ended March 31, 2023	2022
General and Administrative	**158**	199
Finance Costs	**194**	229
Interest Income	**(33)**	(15)
Integration and Transaction Costs	**20**	24
Foreign Exchange (Gain) Loss, Net	**(7)**	(102)
Revaluation (Gain) Loss	**33**	—
Re-measurement of Contingent Payments	**17**	236
(Gain) Loss on Divestiture of Assets	**(1)**	(242)
Other (Income) Loss, Net	**(6)**	(370)
	375	(41)

General and Administrative

Primary drivers of our general and administrative expenses were workforce costs, information technology costs and employee long-term incentive costs. General and administrative expenses decreased $41 million compared with 2022 primarily due to lower long-term incentive costs as a result of changes in our share price, partially offset by increased information technology costs. Our closing common share price on March 31, 2023, was $23.58, a decrease from $26.27 on December 31, 2022. Our closing common share price on March 31, 2022, was $20.84, an increase from $15.51 on December 31, 2021.

Finance Costs

Finance costs decreased by $35 million in the first three months of 2023 compared with 2022, primarily as a result of debt purchases in 2022 that lowered the Company's average long-term debt. Refer to the Liquidity and Capital Resources section of this MD&A for further details on long-term debt.

The weighted average interest rate of outstanding debt for the year ended March 31, 2023, was 4.7 percent (2022 – 4.7 percent).

Integration and Transaction Costs

In the first quarter of 2023, we incurred integration and transaction costs of $20 million associated with the Toledo Acquisition.

Integration and transaction costs of $24 million in the first quarter of 2022 related to the integration of Cenovus and Husky Energy Inc.

Foreign Exchange

($ millions)	Three Months Ended March 31, 2023	2022
Unrealized Foreign Exchange (Gain) Loss	**14**	(139)
Realized Foreign Exchange (Gain) Loss	**(21)**	37
	(7)	(102)

In the first quarter of 2023, unrealized foreign exchange losses and realized foreign exchange gains were mainly related to working capital.

Revaluation (Gain) Loss

Cenovus recognized a revaluation loss of $33 million in the first quarter of 2023 as part of the Toledo Acquisition. 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 4 of the interim Consolidated Financial Statements for further details.

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 16 of the interim Consolidated Financial Statements for further details.

The contingent payment is accounted for as a financial option with changes in fair value recognized in net earnings (loss). As at March 31, 2023, the fair value of the variable payment was estimated to be $394 million resulting in a non-cash re-measurement loss of $17 million. In the first quarter of 2023, we paid $92 million under this agreement, which was recognized in cash from (used in) investing activities with no impact to Adjusted Funds Flow. As at March 31, 2023, $42 million is payable under this agreement. As of March 31, 2023, average WCS forward pricing for the remaining term of the variable payment is approximately $77.54 per barrel.

The contingent payment associated with the acquisition of a 50 percent interest in the FCCL Partnership from ConocoPhillips Company and certain of its subsidiaries ended on May 17, 2022, and the final payment was made in July 2022. In the first quarter of 2022, we paid $160 million under this agreement, which was recognized in cash from (used in) operating activities and reduced Adjusted Funds Flow. In the first quarter of 2022, a non-cash remeasurement loss of $236 million was recorded.

(Gain) Loss on Divestiture of Assets

In the first quarter of 2022, we recognized a gain on divestiture of assets of $242 million, primarily due to the sale of our Tucker and Wembley assets.

Other (Income) Loss, Net

In the first three months of 2023, other income was $6 million (2022 – $370 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.

DD&A

DD&A for the three months ended March 31, 2023, was $21 million (2022 – $30 million).

Income Taxes

	Three Months Ended March 31,	
($ millions)	**2023**	2022
Current Tax		
Canada	**258**	367
United States	**17**	20
Asia Pacific	**46**	38
Other International	**6**	—
Total Current Tax Expense (Recovery)	**327**	425
Deferred Tax Expense (Recovery)	**(370)**	118
	(43)	543

For the three months ended March 31, 2023, the Company recorded a current tax expense related to operations in all jurisdictions that Cenovus operates. The decrease is due to lower earnings compared with 2022. In addition, Cenovus recorded a deferred tax recovery of $370 million of which $176 million related to a step-up in the tax basis on the Toledo Acquisition, contributing to a negative 7.3 percent effective tax rate. Excluding the impact of the Toledo Acquisition, the effective tax rate would be consistent with the statutory rate.

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

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

LIQUIDITY AND CAPITAL RESOURCES

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

	Three Months Ended March 31,	
($ millions)	**2023**	2022
Cash From (Used In)		
Operating Activities	**(286)**	1,365
Investing Activities	**(1,755)**	337
Net Cash Provided (Used) Before Financing Activities	**(2,041)**	1,702
Financing Activities	**(435)**	(1,093)
Effect of Foreign Exchange on Cash and Cash Equivalents	**1**	(83)
Increase (Decrease) in Cash and Cash Equivalents	**(2,475)**	526

As at ($ millions)	**March 31, 2023**	December 31, 2022
Cash and Cash Equivalents	**2,049**	4,524
Total Debt	**8,681**	8,806

Cash From (Used in) Operating Activities

For the three months ended March 31, 2023, cash used in operating activities was $286 million compared with cash from operating activities of $1.4 billion in the same period in 2022. The change was due to lower Operating Margin and a working capital build driven largely by the payment of the December 31, 2022 income tax liability of $1.2 billion.

Cash From (Used in) Investing Activities

Cash used in investing activities was $1.8 billion in the first quarter of 2023 compared with cash from investing activities of $337 million in 2022. The change was largely due to proceeds from divestitures in the first quarter of 2022, the closing of the Toledo Acquisition and higher capital spending in 2023. In addition, non-cash working capital decreased in 2023 primarily due to the Sunrise contingent payment and insurance proceeds in 2022 related to the Superior incident.

Cash From (Used in) Financing Activities

Cash used in financing activities was $435 million in the first quarter of 2023 (2022 – $1.1 billion). The decrease was mainly due to debt purchases of US$402 million in 2022 and higher common share purchases through our NCIB in 2022, partially offset by higher base dividend payments in 2023.

In the first quarter of 2023, the Company purchased 1.6 million common shares (2022 – 24.6 million) through our NCIB, at a volume weighted average price of $25.54 per common share for a total of $40 million (2022 – $466 million). The common shares were subsequently cancelled. In the first three months of 2023, we paid base dividends of $200 million on our common shares (2022 – $69 million).

In the first quarter of 2023, we repaid $115 million in short-term borrowings.

Working Capital

Excluding the contingent payment, our adjusted working capital at March 31, 2023, was $4.2 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 the Company has after financing its capital programs. Excess Free Funds Flow is a non-GAAP financial measure used by the Company to deliver shareholder returns and allocate capital according to our shareholder returns plan.

	Three Months Ended March 31,	
($ millions)	**2023**	2022
Cash From (Used in) Operating Activities	**(286)**	1,365
(Add) Deduct:		
Settlement of Decommissioning Liabilities	**(48)**	(19)
Net Change in Non-Cash Working Capital	**(1,633)**	(1,199)
Adjusted Funds Flow	**1,395**	2,583
Capital Investment	**1,101**	746
Free Funds Flow	**294**	1,837
Add (Deduct):		
Base Dividends Paid on Common Shares	**(200)**	(69)
Dividends Paid on Preferred Shares	**(18)**	(9)
Settlement of Decommissioning Liabilities	**(48)**	(19)
Principal Repayment of Leases	**(70)**	(75)
Acquisitions, Net of Cash Acquired	**(465)**	—
Proceeds From Divestitures	**8**	950
Excess Free Funds Flow	**(499)**	2,615

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 December 31, 2022, our long-term debt was $8.7 billion, resulting in a Net Debt position of $4.3 billion. Therefore, our returns to shareholders target for the three months ended March 31, 2023, was 50 percent of that quarter's Excess Free Funds Flow. During the three months ended March 31, 2023, Excess Free Funds Flow was negative $499 million. As such our target return was $nil and no variable dividend was declared for the second quarter. We returned $40 million to our shareholders through share buybacks in the quarter.

($ millions)	Three Months Ended March 31, 2023
Excess Free Funds Flow	**(499)**
Target Return	**—**
Less: Purchase of Common Shares Under NCIBs	**(40)**
Amount Available for Variable Dividend	**—**

On March 31, 2023, our Net Debt position was $6.6 billion and as a result our returns to shareholders target for the three months ended June 30, 2023, will be 50 percent of the second quarter's Excess Free Funds Flow.

Short-Term Borrowings

As at March 31, 2023, $nil was drawn on the WRB uncommitted demand facilities (December 31, 2022 – the Company's proportionate share was US$85 million (C$115 million)).

Long-Term Debt and Total Debt

Total debt and long-term debt as at March 31, 2023, was $8.7 billion. As at December 31, 2022, total debt was $8.8 billion which included $8.7 billion of long-term debt.

As at March 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 March 31, 2023:

($ millions)	Maturity	Amount Available
Cash and Cash Equivalents	**N/A**	**2,049**
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**	**964**
WRB (3)	**N/A**	**304**

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

(2) Our uncommitted demand facilities includes $1.9 billion, of which $1.4 billion may be drawn for general purposes, or the full amount can be available to issue letters of credit. As at March 31, 2023, there were outstanding letters of credit aggregating to $461 million (December 31, 2022 – $490 million) and no direct borrowings.

(3) Represents Cenovus's proportionate share of US$225 million available to cover short-term working capital requirements. As at March 31, 2023, $nil 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.

U.S. Dollar Denominated Unsecured Notes and Canadian Dollar Unsecured Notes

At March 31, 2023, the total outstanding principal amount of U.S. dollar denominated unsecured notes was US$4.8 billion (December 31, 2022 – US$4.8 billion) and the total outstanding principal amount of Canadian dollar denominated unsecured notes was $2.0 billion (December 31, 2022 – $2.0 billion).

Base Shelf Prospectus

We have a base shelf prospectus that allows us to offer, from time to time, up to US$5.0 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere, where permitted by law. The base shelf prospectus will expire in November 2023. As at March 31, 2023, US$4.7 billion remained available under the base shelf prospectus for permitted offerings (December 31, 2022 – US$4.7 billion). Offerings under the base shelf prospectus are subject to market availability.

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 14 of the interim Consolidated Financial Statements for further details.

We define Net Debt as short-term borrowings and the current and long-term portions of long-term debt, net of cash and cash equivalents and short-term investments. The components of the ratios include Capitalization, Adjusted Funds Flow and Adjusted EBITDA. We define Capitalization as Net Debt plus 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 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	**March 31, 2023**	December 31, 2022
Net Debt to Capitalization Ratio (percent)	**19**	13
Net Debt to Adjusted Funds Flow Ratio (times)	**0.7**	0.4
Net Debt to Adjusted EBITDA Ratio (times)	**0.6**	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 March 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 March 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 common share purchase warrants (“Cenovus Warrants”) are listed on the Toronto Stock Exchange (“TSX”) and New York Stock Exchange (“NYSE”). Our cumulative redeemable preferred shares series 1, 2, 3, 5 and 7 are listed on the TSX.

As at March 31, 2023, there were approximately 1,908.4 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 19 of the interim Consolidated Financial Statements for further details.

Cenovus has an NCIB program to purchase up to 136.7 million common shares during the period from November 9, 2022, to November 8, 2023. In the first three months of 2023, Cenovus purchased and cancelled 1.6 million common shares for $40 million (2022 – 24.6 million common shares for $466 million), at a volume weighted average price of $25.54 per common share (2022 – $18.91 per common share) through our NCIB program. Paid in surplus was reduced by $27 million (2022 – $256 million), representing the excess of the purchase price of the common shares over their average carrying value. From April 1, 2023, to April 21, 2023, the Company purchased an additional 2.1 million common shares for $51 million. As at April 21, 2023, 121.5 million common shares remain available for purchase under the NCIB, which expires on November 8, 2023.

As at March 31, 2023, there were approximately 55.3 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 19 of the interim Consolidated Financial Statements for further details.

Refer to Note 21 of the interim Consolidated Financial Statements for further details on our stock option plans and our performance share unit, restricted share unit and deferred share unit plans.

Our outstanding share data is as follows:

As at April 21, 2023	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares	**1,906,854**	**N/A**
Cenovus Warrants	**55,273**	**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	**17,276**	**11,931**
Other Stock-Based Compensation Plans	**18,998**	**1,648**

Common Share Dividends

In the first quarter of 2023, we paid base dividends of $200 million or $0.105 per common share (2022 – $69 million or $0.035 per common share).

The Board declared a second quarter base dividend of $0.140 per common share, payable on June 30, 2023, to common shareholders of record as at June 15, 2023, an increase of 33 percent from our first quarter dividend declared in February 2023.

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

Cumulative Redeemable Preferred Share Dividends

In the first quarter of 2023, dividends of $18 million were paid on the series 1, 2, 3, 5 and 7 preferred shares (2022 — $9 million) representing the dividends declared by the Board for the fourth quarter of 2022 and first quarter of 2023. The declaration of preferred share dividends is at the sole discretion of the Board and is considered quarterly. The Board declared a second quarter dividend on the series 1, 2, 3, 5 and 7 preferred shares of $9 million, payable on June 30, 2023, to preferred shareholders of record as of June 15, 2023.

Capital Investment Decisions

Our 2023 capital program is forecast to be between $4.0 billion and $4.5 billion, including approximately $2.8 billion of sustaining capital and between $1.2 billion to $1.7 billion of optimization and growth capital. Our Future Capital Investment is focused on disciplined capital allocation, investment plans to progress opportunities across our integrated portfolio, cost control and positioning the Company for continued growth in shareholder returns. We expect our annual upstream production to average between 790 thousand BOE per day and 810 thousand BOE per day and our downstream crude oil throughput average between 580 thousand barrels per day to 610 thousand barrels per day in 2023. Our guidance as updated on April 25, 2023, is available at our website at cenovus.com.

Contractual Obligations and Commitments

We have obligations for goods and services entered into in the normal course of business. Obligations that have original maturities of less than one year are excluded. For further information, see Note 26 to the interim Consolidated Financial Statements.

Our total commitments were $25.8 billion as at March 31, 2023, of which $20.7 billion are for various transportation and storage commitments and $1.8 billion are for product purchase commitments. Transportation commitments include $9.1 billion that are subject to regulatory approval or have been approved, but are not yet in service. Terms are up to 20 years subsequent to the date of commencement and should help align with the Company’s future transportation requirements.

We acquired $538 million of commitments as part of the Toledo Acquisition.

Our commitments with HMLP at March 31, 2023, include $2.2 billion related to long-term transportation and storage commitments.

As at March 31, 2023, outstanding letters of credit issued as security for performance under certain contracts totaled $461 million.

Legal Proceedings

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

Transactions with Related Parties

Cenovus holds a 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. We are also the contractor for HMLP and construct its assets on a cost recovery basis with certain restrictions. For the three months ended March 31, 2023, we charged HMLP $32 million for construction and management services (2022 – $48 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. For the three months ended March 31, 2023, we incurred costs of $67 million for the use of HMLP's pipeline systems, as well as transportation and storage services (2022 – $68 million).

RISK MANAGEMENT AND RISK FACTORS

For a full understanding of the risks that impact us, the following discussion should be read in conjunction with the Risk Management and Risk Factors section of our 2022 annual MD&A.

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

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATION UNCERTAINTIES AND ACCOUNTING POLICIES

Management is required to make estimates and assumptions, as well as use judgment in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our material accounting policies are reviewed annually by the Audit Committee of the Board. Further details on the basis of preparation and our material accounting policies can be found in the notes to the Consolidated Financial Statements for the year ended December 31, 2022.

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

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in our annual and interim Consolidated Financial Statements. A full list of the critical judgments used in applying accounting policies and key sources of estimation uncertainty can be found in our Consolidated Financial Statements for the year ended December 31, 2022. There have been no changes to our critical judgments used in applying accounting policies and key sources of measurement uncertainty during the three months ended March 31, 2023.

New Accounting Standards and Interpretations not yet Adopted

There are new accounting standards, amendments to accounting standards and interpretations that were effective for annual periods beginning on or after January 1, 2023, but are not material to Cenovus's operations. There were no new or amended accounting standards or interpretations issued during the three months ended March 31, 2023, that are expected to have a material impact on the Company's interim Consolidated Financial Statements.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at March 31, 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 March 31, 2023.

On February 28, 2023, Cenovus closed the Toledo Acquisition. As permitted by and in accordance with, National Instrument 52-109, *"Certification of Disclosure in Issuers' Annual and Interim Filings"*, and guidance issued by the U.S. Securities and Exchange Commission, Management has limited the scope and design of ICFR and DC&P to exclude the controls, policies and procedures in respect of the business acquired from BP. Such scope limitation is primarily due to the time required for Management to assess the ICFR and DC&P relating to BP in a manner consistent with our other operations. Further integration will take place throughout the remainder of the year as processes and systems align.

Assets acquired from BP represented approximately one percent of Cenovus's total assets at March 31, 2023. Revenues attributable to assets acquired from BP were less than one percent of Cenovus's total revenues for the three months ended March 31, 2023. Operating expenses attributable to assets acquired from BP were less than three percent of Cenovus's total operating expenses for the three months ended March 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 have been 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", "future", "may", "on track", "objective", "opportunities", "plan", "prioritize", "strive", "target", and "will", or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: shareholder value and returns; cost structure and control; GHG emissions; interest expense; margins; infrastructure; operating and capital costs; capital investment, allocation, and structure; capital discipline; safety performance; sustainability leadership; Free Funds Flow; Excess Free Funds Flow; balance sheet management; dividends of any kind; share repurchases under the NCIB; reinvestment in the business; diversifying the portfolio; deleveraging; risk profile; near-term funding requirements; meeting payment obligations; maintaining credit ratings; debt; Net Debt; Net Debt to Adjusted Funds Flow Ratio; Net Debt to Adjusted EBITDA Ratio; drawing on credit facilities; liquidity; resiliency; flexibility; capital expenditures; production and production rates; throughput; consistent and reliable operations at all operated assets; downstream operating performance; liabilities from legal proceedings; cash flow; financial results; planned turnarounds; variable payments; provision for income tax; financial resilience; capturing value; monitoring market fundamentals; mitigating the impact of commodity differentials; plans to achieve targets for: climate and GHG emissions, water stewardship, biodiversity, indigenous reconciliation, Inclusion and diversity; the focus of our 2023 budget; optimizing run rates at the Company's refineries; return of the Superior Refinery to full operations; integration of the Toledo Refinery and ramp up to full rates; transportation and storage commitments; progressing the West White Rose project, including delivering first oil and achieving peak production; resuming production at the Terra Nova ALE project; first gas production from the MAC field in Indonesia; 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 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 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 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 2023 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.

2023 guidance, as updated on April 25, 2023, and available on cenovus.com, assumes: Brent prices of US$80.00 per barrel, WTI prices of US$75.00 per barrel; WCS of US$57.00 per barrel; Differential WTI-WCS of US$18.00 per barrel; AECO natural gas prices of $3.10 per Mcf; Chicago 3-2-1 crack spread of US$28.00 per barrel; and an exchange rate of $0.74 US$/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 effect of the COVID-19 pandemic, including any variants thereof, on the Company's business, including any related restrictions, containment, and treatment measures taken by varying levels of government in the jurisdictions in which the Company operates; the success of the Company's COVID-19 workplace policies; 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 is 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 manufacturing 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 manufacturing 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 sedar.com, 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 have been used in this document:

Crude Oil		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
WTI	West Texas Intermediate	MMcf/d	million cubic feet per day	MBOE/d	thousand barrels of oil equivalent per day
WCS	Western Canadian Select			OPEC	Organization of Petroleum Exporting Countries
				OPEC+	OPEC and a group of 10 non-OPEC members
				GHG	Greenhouse Gas
				AECO	Alberta Energy Company
				NCIB	Normal Course Issuer Bid
				NYMEX	New York Mercantile Exchange
				SAGD	steam-assisted gravity drainage

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 have been 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 for the Upstream or Downstream segment, 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 the Upstream or Downstream segment 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.

	Three Months Ended March 31,					
	2023	2022	**2023**	2022	**2023**	2022
($ millions)	**Upstream** [1]		**Downstream** [1]		**Total**	
Revenues						
Gross Sales	**7,415**	10,897	**7,368**	8,116	**14,783**	19,013
Less: Royalties	**596**	1,185	**—**	—	**596**	1,185
	6,819	9,712	**7,368**	8,116	**14,187**	17,828
Expenses						
Purchased Product	**1,069**	1,818	**6,222**	6,817	**7,291**	8,635
Transportation and Blending	**2,994**	3,194	**—**	—	**2,994**	3,194
Operating	**1,029**	909	**754**	645	**1,783**	1,554
Realized (Gain) Loss on Risk Management	**16**	871	**1**	110	**17**	981
Operating Margin	**1,711**	2,920	**391**	544	**2,102**	3,464

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

Operating Margin by Asset

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

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

Operating Margin by Asset

($ millions)	Three Months Ended March 31, 2022 Asia Pacific	Atlantic	Offshore [1]
Revenues			
Gross Sales	395	172	567
Less: Royalties	22	10	32
	373	162	535
Expenses			
Transportation and Blending	—	4	4
Operating	27	46	73
Operating Margin	346	112	458

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

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

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

($ millions)	Three Months Ended March 31, **2023**	2022
Cash From (Used in) Operating Activities	**(286)**	1,365
(Add) Deduct:		
Settlement of Decommissioning Liabilities	**(48)**	(19)
Net Change in Non-Cash Working Capital	**(1,633)**	(1,199)
Adjusted Funds Flow	**1,395**	2,583
Capital Investment	**1,101**	746
Free Funds Flow	**294**	1,837
Add (Deduct):		
Base Dividends Paid on Common Shares	**(200)**	(69)
Dividends Paid on Preferred Shares	**(18)**	(9)
Settlement of Decommissioning Liabilities	**(48)**	(19)
Principal Repayment of Leases	**(70)**	(75)
Acquisitions, Net of Cash Acquired	**(465)**	—
Proceeds From Divestitures	**8**	950
Excess Free Funds Flow	**(499)**	2,615

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 divided by barrels of crude oil unit throughput in our downstream operations.

Canadian Manufacturing

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

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

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

	Three Months Ended March 31, 2022				
	Basis of Refining Margin Calculation				
($ millions)	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Manufacturing [2]
Revenues	756	186	942	665	1,607
Purchased Product	585	143	728	607	1,335
Gross Margin	171	43	214	58	272

	Operating Statistics		
	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
Heavy Crude Oil Unit Throughput (Mbbls/d)	70.7	27.4	98.1
Refining Margin ($/bbl)	26.98	17.33	24.28

(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. Manufacturing

	Three Months Ended March 31,	
($ millions)	**2023**	2022
Revenues [1]	5,860	6,509
Purchased Product [1]	5,129	5,482
Gross Margin	731	1,027
Crude Oil Unit Throughput (Mbbls/d)	359.2	403.7
Refining Margin ($/bbl)	22.62	28.26

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

Per Unit DD&A

Per Unit DD&A is a specified financial measure used to measure DD&A on a per-unit basis. We define Per Unit DD&A as DD&A divided by sales volumes.

Netback Reconciliations

Netback is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring operating performance and is also presented on a per-unit basis. 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.

Total Production

Upstream Financial Results

		Adjustments					Basis of Netback Calculation
Three Months Ended March 31, 2023 ($ millions)	Total Upstream (1)	Condensate	Third-Party Sourced	Internal Consumption (2)	Equity Adjustment (3)	Other (4)	Total Upstream
Gross Sales	**7,415**	**(2,445)**	**(1,008)**	**(187)**	**73**	**(107)**	**3,741**
Royalties	**596**	**—**	**—**	**—**	**23**	**—**	**619**
Purchased Product	**1,069**	**—**	**(1,008)**	**—**	**—**	**(61)**	**—**
Transportation and Blending	**2,994**	**(2,445)**	**—**	**—**	**—**	**(26)**	**523**
Operating	**1,029**	**—**	**—**	**(187)**	**10**	**(43)**	**809**
Netback	**1,727**	**—**	**—**	**—**	**40**	**23**	**1,790**
Realized (Gain) Loss on Risk Management	**16**	**—**	**—**	**—**	**—**	**(1)**	**15**
Operating Margin	**1,711**	**—**	**—**	**—**	**40**	**24**	**1,775**

		Adjustments					Basis of Netback Calculation
Three Months Ended March 31, 2022 ($ millions)	Total Upstream (1)	Condensate	Third-Party Sourced	Internal Consumption (2)	Equity Adjustment (3)	Other (4)	Total Upstream
Gross Sales	**10,897**	(2,758)	(1,750)	(239)	61	(76)	**6,135**
Royalties	**1,185**	—	—	—	28	—	**1,213**
Purchased Product	**1,818**	—	(1,750)	—	—	(68)	**—**
Transportation and Blending	**3,194**	(2,758)	—	—	—	1	**437**
Operating	**909**	—	—	(239)	7	(21)	**656**
Netback	**3,791**	—	—	—	26	12	**3,829**
Realized (Gain) Loss on Risk Management	**871**	—	(4)	—	—	—	**867**
Operating Margin	**2,920**	—	4	—	26	12	**2,962**

(1) These amounts, excluding netback, are found in Note 1 of the interim Consolidated Financial Statements.
(2) Represents natural gas volumes produced by the Conventional segment used for internal consumption by the Oil Sands segment.
(3) Revenues and expenses related to the HCML joint venture are accounted for using the equity method in the consolidated financial statements.
(4) Other includes construction, transportation and blending and third-party processing margin.

Oil Sands

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

	Basis of Netback Calculation	Adjustments			
Three Months Ended March 31, 2023 ($ millions)	Total Oil Sands	Condensate	Third-party Sourced	Other (2)	Total Oil Sands (3)
Gross Sales	**2,888**	**2,445**	**498**	**80**	**5,911**
Royalties	**516**	**—**	**—**	**—**	**516**
Purchased Product	**—**	**—**	**498**	**61**	**559**
Transportation and Blending	**470**	**2,445**	**—**	**26**	**2,941**
Operating	**729**	**—**	**—**	**8**	**737**
Netback	**1,173**	**—**	**—**	**(15)**	**1,158**
Realized (Gain) Loss on Risk Management	**7**	**—**	**—**	**1**	**8**
Operating Margin	**1,166**	**—**	**—**	**(16)**	**1,150**

	Basis of Netback Calculation						
Three Months Ended March 31, 2022 ($ millions)	Foster Creek	Christina Lake	Sunrise	Other Oil Sands (1)	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
Gross Sales	1,820	2,232	232	976	**5,260**	4	**5,264**
Royalties	388	584	11	99	**1,082**	—	**1,082**
Purchased Product	—	—	—	—	**—**	—	**—**
Transportation and Blending	178	151	30	38	**397**	—	**397**
Operating	202	219	39	221	**681**	6	**687**
Netback	1,052	1,278	152	618	**3,100**	(2)	**3,098**
Realized (Gain) Loss on Risk Management							**867**
Operating Margin							**2,231**

	Basis of Netback Calculation	Adjustments			
Three Months Ended March 31, 2022 ($ millions)	Total Oil Sands	Condensate	Third-party Sourced	Other (2)	Total Oil Sands (3)
Gross Sales	**5,264**	2,758	1,144	52	**9,218**
Royalties	**1,082**	—	—	—	**1,082**
Purchased Product	**—**	—	1,144	68	**1,212**
Transportation and Blending	**397**	2,758	—	1	**3,156**
Operating	**687**	—	—	15	**702**
Netback	**3,098**	—	—	(32)	**3,066**
Realized (Gain) Loss on Risk Management	**867**	—	—	—	**867**
Operating Margin	**2,231**	—	—	(32)	**2,199**

(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.

Conventional

	Basis of Netback Calculation	Adjustments		
Three Months Ended March 31, 2023 ($ millions)	Conventional	Third-party Sourced	Other (1)	Conventional (2)
Gross Sales	494	510	27	1,031
Royalties	54	—	—	54
Purchased Product	—	510	—	510
Transportation and Blending	48	—	—	48
Operating	146	—	4	150
Netback	246	—	23	269
Realized (Gain) Loss on Risk Management	8	—	—	8
Operating Margin	238	—	23	261

	Basis of Netback Calculation	Adjustments		
Three Months Ended March 31, 2022 ($ millions)	Conventional	Third-party Sourced	Other (1)	Conventional (2)
Gross Sales	482	606	24	1,112
Royalties	71	—	—	71
Purchased Product	—	606	—	606
Transportation and Blending	36	—	(2)	34
Operating	128	—	6	134
Netback	247	—	20	267
Realized (Gain) Loss on Risk Management	—	4	—	4
Operating Margin	247	(4)	20	263

(1) Reflects Operating Margin from processing facilities.
(2) These amounts, excluding netback, are found in Note 1 of the interim Consolidated Financial Statements.

Offshore

	Basis of Netback Calculation					Adjustments		
Three Months Ended March 31, 2023 ($ millions)	China	Indonesia (1)	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment (1)	Other (2)	Total Offshore (3)
Gross Sales	324	73	397	149	546	(73)	—	473
Royalties	18	23	41	8	49	(23)	—	26
Purchased Product	—	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	5	5	—	—	5
Operating	22	14	36	85	121	(10)	31	142
Netback	284	36	320	51	371	(40)	(31)	300
Realized (Gain) Loss on Risk Management					—	—	—	—
Operating Margin					371	(40)	(31)	300

	Basis of Netback Calculation					Adjustments		
Three Months Ended March 31, 2022 ($ millions)	China	Indonesia (1)	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment (1)	Other (2)	Total Offshore (3)
Gross Sales	395	61	456	172	628	(61)	—	567
Royalties	22	28	50	10	60	(28)	—	32
Purchased Product	—	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	4	4	—	—	4
Operating	23	11	34	46	80	(7)	—	73
Netback	350	22	372	112	484	(26)	—	458
Realized (Gain) Loss on Risk Management					—	—	—	—
Operating Margin					484	(26)	—	458

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

Sales Volumes [1]

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

	Three Months Ended March 31,	
(MBOE/d)	**2023**	2022
Oil Sands		
Foster Creek	**183.6**	200.1
Christina Lake	**237.9**	263.4
Sunrise	**39.8**	25.3
Other Oil Sands	**115.7**	121.1
Total Oil Sands	**577.0**	609.9
Conventional	**123.9**	125.2
Sales before Internal Consumption	**700.9**	735.1
Less: Internal Consumption [2]	**(90.2)**	(87.9)
Sales after Internal Consumption	**610.7**	647.2
Offshore		
Asia Pacific - China	**43.0**	53.6
Asia Pacific - Indonesia	**13.7**	9.1
Asia Pacific - Total	**56.7**	62.7
Atlantic	**15.7**	14.6
Total Offshore	**72.4**	77.3
Total Sales	**683.1**	724.5

(1) Presented on a dry bitumen basis.
(2) Less natural gas volumes used for internal consumption by the Oil Sands segment.