2022 ANNUAL REPORT

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For additional information about forward-looking statements, specified financial measures and reserves contained in this Annual Report, see the Advisory on page 163.

At Cenovus, our purpose is to energize the world to make people's lives better.

INCREASING OUR RESILIENCY BY GROWING AND OPTIMIZING OUR PORTFOLIO

The targeted enhancement of our portfolio has been a key focus over the last two years as we shape a resilient Cenovus built for the future. This includes strategic divestitures and acquisitions, and disciplined investment in focused growth and optimization projects.

During 2022, we closed the acquisition of Sunrise, giving us full ownership, having an immediate positive impact on production and cash flow. We're now working to unlock further value by integrating the Cenovus operating model into that facility. We also rebalanced our Atlantic portfolio, reaching an agreement to restart the West White Rose project, which included a reduced interest of 12.5 percent transferred to our partner. First oil from West White Rose is expected in 2026. In a separate agreement, we exited our position in the undeveloped Bay du Nord field.

In 2022, we closed the sale of more than 300 gas stations in our retail network, as well as a number of conventional oil and natural gas properties.

We fully own and operate the Toledo Refinery in Ohio, providing an opportunity to further integrate our heavy oil production and refining capabilities, solidify our refining footprint in the U.S. Midwest and increase our ability to capture margin throughout the value chain. The transaction, announced in August 2022, closed in February 2023.

We will continue our focus on disciplined investment in 2023 with further optimization including debottlenecking plans for Foster Creek and the Lloydminster Refinery, the Narrows Lake tie-in at Christina Lake, and preparing the Lloydminster Upgrader and Refinery to access feedstock from Foster Creek in addition to the current crude supply from the Lloydminster area.

Our investments will also progress plans to reduce our carbon footprint, and we're putting capital aside to do just that. Over the next five years, Cenovus plans to spend approximately $1 billion on initiatives that advance our emissions reductions goals. This includes advancing carbon capture projects at the Minnedosa Ethanol Plant, Elmworth gas plant, Lloydminster Upgrader and Christina Lake, as well as methane reduction initiatives across conventional operations. We will also continue our work with the Pathways Alliance, which we jointly founded, on the goal of net zero emissions from oil sands production by 2050.

MAKING PROGRESS ON OUR COMMITMENT TO BIODIVERSITY

Biodiversity has long been a focus for Cenovus. We are more than halfway to our target of reclaiming 3,000 decommissioned well sites by year-end 2025. We also have restored more than 200,000 acres of caribou habitat, contributing to our goal of restoring more habitat than we use in the Cold Lake caribou range by year-end 2030.

In 2022, we received more than 500 reclamation certificates for well sites and associated facilities.

We've also seen positive results from the restoration of old seismic lines in the Cold Lake area. Linear features such as seismic lines, roads and pipelines create highway-type corridors through the forest that can allow predators to hunt caribou faster and further. However, a multi-year study we conducted in collaboration with partners in government and academia found that treating areas for restoration through the use of trees, rough surfaces and woody material reduced travel speeds of caribou and predators like wolves and bears, making the chances of an encounter less likely. We continue to develop, test and refine evidence-based techniques for land restoration using studies such as these.

MESSAGE FROM OUR PRESIDENT & CHIEF EXECUTIVE OFFICER

2021 was about establishing Cenovus as a resilient new energy leader and in 2022 we demonstrated what this new company can do.

As I prepare to take on the role of Executive Chair of our Board of Directors, I know Cenovus is well positioned for long-term success. And I know our incoming President & CEO Jon McKenzie will continue to unlock additional opportunities over the coming year and beyond, entrenching our position as a leader in delivering total shareholder returns.

The capital allocation framework we implemented in April 2022 is clear about how we maintain balance sheet strength while delivering returns to shareholders. We employed that framework to provide annual shareholder returns in 2022 of more than $3.4 billion, including share purchases, our first-ever variable dividend, and our base dividend, which we tripled. Our total shareholder returns continued to outperform the S&P/TSX composite and energy indices in 2022, while we also drove down net debt by more than $5.3 billion through the year, further fortifying our balance sheet.

However, we can't truly consider ourselves successful unless we can point to an equally strong safety record. Cenovus improved its safety performance year over year with notable improvements in our recordable injury frequency at Lima Refinery and in our well delivery group. However, some of the recent incidents at our non-operated assets are an important reminder that we must never become complacent or take our safety performance for granted. We will be unrelenting in our efforts to ensure that Cenovus's strong safety culture is embedded at every site where we operate.

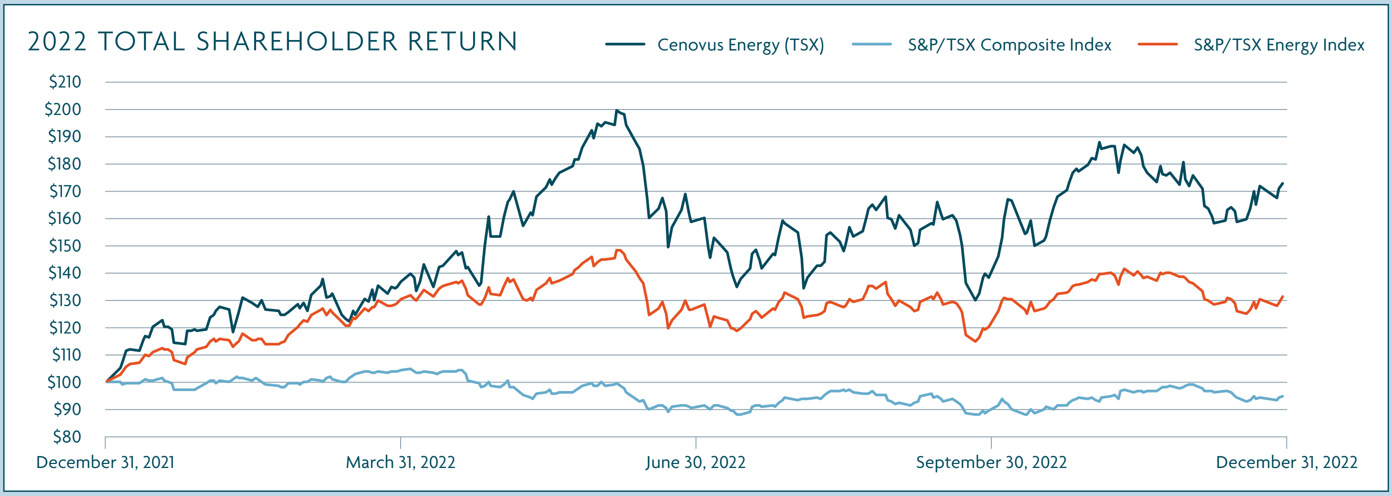
Jon and I have worked closely over the past few years to build our integrated strategy. In 2022, we further refined our portfolio with a focus on strategic growth and optimization, while also increasing the physical integration of our upstream and downstream businesses. We completed several asset sales, including the divestment of our Tucker and Wembley assets and our retail fuels network. We are now the sole owner of Sunrise, de-risked our Atlantic portfolio and in February 2023 closed the transaction to fully own and operate the Toledo Refinery. At Superior, the refinery is safely ramping up to full operations.

We added new production at existing operations with the startup of our Spruce Lake North thermal project in Saskatchewan and first gas at the MBH and MDA fields offshore Indonesia, exiting the year with overall production of more than 800,000 barrels of oil equivalent per day. While our downstream throughput in 2022 was affected by turnarounds and unplanned outages, we expect stronger performance this year, bolstered in part by the addition of barrels from Superior and Toledo.

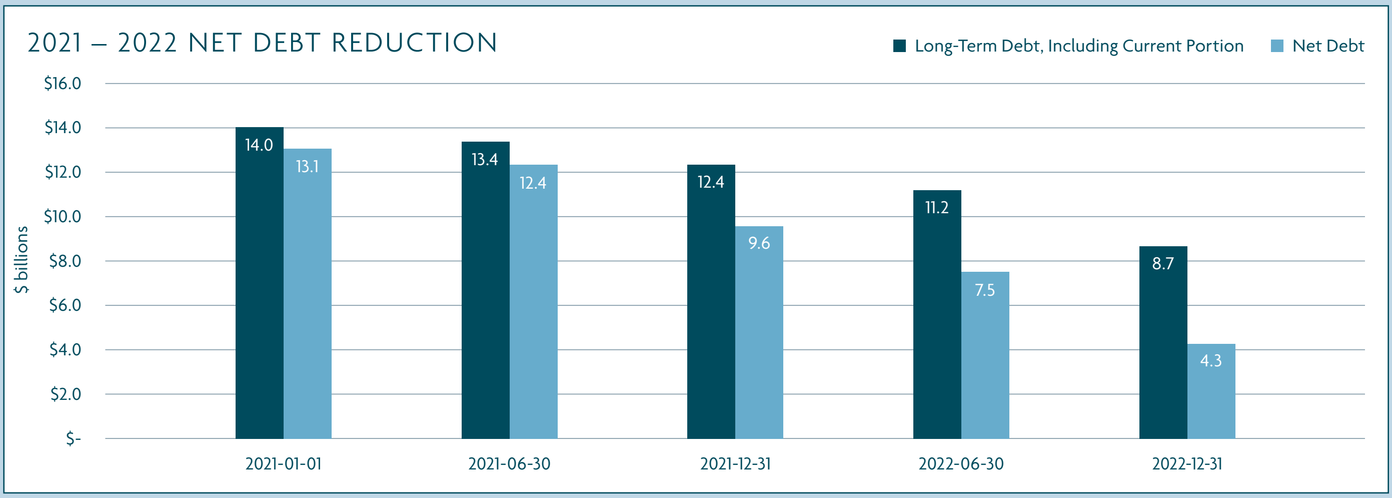
Our reliable operating performance and disciplined capital allocation, combined with strong commodity prices, have helped us accelerate our debt reduction. During the year, we reduced our long-term debt including current portion by $8.7 billion from $12.4 billion at the end of 2021, and drove down net debt by more than half. In 2022, the company returned more than $2.5 billion in value through its share buyback program and delivered over $900 million to shareholders in both base and variable dividends. In November 2022, we received TSX approval to purchase up to approximately 137 million additional shares by November 2023 and will continue to view buybacks opportunistically.

Cenovus remains focused on helping support economic self-sustainability in Indigenous communities as part of our environmental, social and governance (ESG) focus on Indigenous reconciliation. Last year we spent the equivalent of about $1 million a day on goods and services from Indigenous-owned businesses in Canada. And we've nearly achieved our minimum target of spending at least $1.2 billion between 2019 and year-end 2025.

A highlight of my tenure as CEO was getting to see first-hand the difference our Indigenous Housing Initiative is having for families. Since 2020, this program has funded 81 new homes in six First Nations and Métis communities near our Christina Lake and Foster Creek operations. It was gratifying and humbling to visit with some of the people living in these new homes and hear how we are making a



Source: Bloomberg



tangible difference in helping address the critical housing situation in Indigenous communities.

We continue to progress another of our ESG targets, reducing our absolute emissions. Over the next five years, Cenovus plans to spend approximately $1 billion on initiatives that advance our emissions reduction goals, ranging from carbon capture projects, methane reduction initiatives and increasing energy efficiency.

It is these efforts to decarbonize that will enable Canada to be the globally preferred barrel in a lower carbon future and allow us to continue to be a significant contributor to the Canadian economy. We know two things – that we must help address the challenge of climate change and also that oil and gas is going to play a significant role in meeting the world's energy needs for decades to come. Canada is well positioned to continue to provide the reliable, affordable energy the world needs.

It's why we continue to work with our peers and all levels of government to meet Canada's and our own net zero ambition. As a co-founder of the Pathways Alliance, we have an ambitious, actionable plan to reduce GHG emissions from the oil sands, in phases. While many different solutions will be needed, significant progress has been achieved on the early-stage work for the Pathways Alliance foundational carbon capture and storage project, including an agreement with the Government of Alberta that allows us to start a detailed evaluation of the proposed underground carbon dioxide storage hub. As other regulatory pieces advance at the federal and provincial levels, we'll be able to progress the project further toward construction. I look forward to playing a leading role in these efforts.

I want to thank all our staff and shareholders for their support over the last five plus years. I also want to extend my appreciation to our retiring Board Chair Keith MacPhail. Keith's extensive business and energy sector expertise has been a great benefit to the Board and our company as we navigated through a period of significant transformation, accelerating our growth and developing a solid strategy, which we believe will support Cenovus's continued success. We have a world-class suite of assets and a solid plan for further sustainable growth and optimization, carrying our existing momentum well into the future.

/s/ Alex Pourbaix
President & Chief Executive Officer

MESSAGE FROM OUR BOARD CHAIR

As we went to print on last year's annual report the world was reeling from the Russian invasion of Ukraine.

Unfortunately, this conflict continues and became one of the dominant news and energy stories of 2022. This war has impacted commodity prices and highlights not only the continuing need for oil and gas, but the importance of secure, reliable sources of that energy. That narrative has continued as we enter 2023, with many analysts predicting another turbulent year for commodities.

We are keenly aware that simply being a reliable supplier of oil and gas isn't enough – Cenovus and Canada need to be leaders in providing lower carbon energy in order to help the country meet its climate goals and for our company to remain competitive in the longer term. As I retire as Board Chair and Alex steps into his new role as Executive Chair, he will remain focused on advancing policy that supports a competitive Canadian energy sector.

Not only was our Board very engaged with our leadership team over the last year discussing methods of reducing our carbon footprint but also on advancing the company's safety, financial and sustainability commitments. In April 2022, the Board approved a new shareholder returns framework which guides how we increase returns, and resulted in our first-ever variable dividend. Buoyed by strong commodity prices and our focused deleveraging of the balance sheet, we exited 2022 with significant reductions in our long-term debt and net debt, at the same time returning approximately $3.4 billion dollars to our shareholders through share buybacks and dividends.

While we are mindful of our current operational and financial strengths, we recognize the need for continued investment to optimize opportunities across our portfolio. With that in mind, the Board approved increased capital spending as part of the company's 2023 budget guidance. Over the next five years, we expect growth to come largely through the extension or expansion of our existing assets in addition to debottlenecking opportunities.

As I look back over my five years as a member of this Board, three as its Chair, I am reminded of the significant transformation the company has undergone, and how the Husky acquisition and other strategic acquisitions and divestitures made us a more resilient, integrated company. I'm also proud of the steps we've taken to increase the diversity of experience on the Board.

Melanie A. Little joined the Board on January 1, 2023, bringing a breadth of operations and regulatory experience in the midstream business, particularly in the U.S. We welcome her perspective and expertise as we unlock further value from our U.S.-based assets. Melanie's addition to the Board, along with Alex's new role as Executive Chair and Jon as a new Director nominee, supports our commitment to a strong and talented Board. This year we also achieved our goal of having at least 30% of our independent directors represented by women by the 2023 Annual Meeting of Shareholders.

As Alex remains an employee and officer of the company in his Executive Chair role, the Board demonstrated its continued commitment to good governance best practices, choosing Claude Mongeau as Lead Director. This will ensure the Board will continue to operate independently with an Executive Chair. Claude will be available to engage with you and other stakeholders on behalf of the Board.

I am confident the measures our management team has taken will ensure Cenovus is positioned for success at multiple commodity price points, and that the focus will remain on executing the strategic plan and disciplined capital allocation.

I want to thank our shareholders and our Board for their support and confidence over the past five years. As a shareholder, I look forward to watching Alex, Claude, Jon and the rest of the Board and Management skillfully navigate the company into the future following the course that we've set out over the past few years.

/s/ Keith MacPhail
Board Chair

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEAR ENDED DECEMBER 31, 2022

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 February 15, 2023 should be read in conjunction with our December 31, 2022 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). All of the information and statements contained in this MD&A are made as of February 15, 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 February 15, 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 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 Advisory section for commonly used oil and gas terms.

OVERVIEW OF CENOVUS

We are a Canadian-based integrated energy company headquartered in Calgary, Alberta. 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. 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."). On January 1, 2021, Cenovus and Husky Energy Inc. ("Husky") closed a transaction to combine the two companies through a plan of arrangement (the "Arrangement").

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 and natural gas 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

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 announced our 2023 budget 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. Our 2023 guidance dated December 5, 2022, is available on our website at cenovus.com. For further details see the Operating and Financial Results section of this MD&A.

Shareholder Returns and Capital Allocation Framework

Maintaining a strong balance sheet with the resilience to withstand price volatility and capitalize on opportunities throughout the commodity price cycle is a key element of Cenovus's capital allocation framework. In April 2022, we announced our updated capital allocation framework to continue to strengthen our balance sheet, which enables flexibility in both high and low commodity price environments, and improves our shareholder value proposition. We have set an ultimate Net Debt Target of $4 billion, which serves as a floor on Net Debt. 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.

Excess Free Funds Flow for the quarter is defined as Free Funds Flow(1):

- Minus base dividends paid on common shares.
- Minus dividends paid on preferred shares.
- Minus other uses of cash, including settlement of decommissioning liabilities and principal repayment of leases.
- Minus any net acquisition costs from acquisition activities closing in the quarter.
- Plus any proceeds from, or less any payments related to, divestiture activities closing in the quarter.

The Company's capital allocation 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. 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 price cycle.

Share buybacks will continue to be 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.

(1) See the Liquidity and Capital Resources section of this MD&A for the calculation of Free Funds Flow.

On September 30, 2022, our long-term debt was $8.8 billion, resulting in a Net Debt position of $5.3 billion. Therefore, our returns to shareholders target for the three months ended December 31, 2022, was 50 percent of that quarter's Excess Free Funds Flow. During the three months ended December 31, 2022, we generated cash from operating activities of $3.0 billion, Excess Free Funds Flow of $786 million and returned $387 million to our shareholders through share buybacks. Returns to shareholders through share buybacks were within $50 million of our Target Return, as such no variable dividend was declared for the quarter.

($ millions)	Three Months Ended December 31, 2022
Excess Free Funds Flow [(1)]	786
Target Return [(2)]	393
Less: Purchase of Common Shares Under our Normal Course Issuer Bid (“NCIB”)	(387)
Amount Available for Variable Dividend	6

(1) Non-GAAP financial measure. See the Advisory.
(2) Based on our capital allocation framework, as a result of Net Debt as at September 30, 2022, being less than $9 billion and greater than $4 billion, target return was determined to be 50 percent of Excess Free Funds Flow for the three months ended December 31, 2022.

On December 31, 2022, our Net Debt position was $4.3 billion and as a result our returns to shareholders target for the three months ended March 31, 2023, will be 50 percent of the first quarter’s Excess Free Funds Flow.

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 Refinery and Superior Refinery, the jointly-owned Wood River and Borger refineries (jointly owned with operator Phillips 66) and the jointly-owned Toledo Refinery (jointly owned with operator BP Products North America Inc. (“BP”)). Cenovus also markets some of its own and third-party volumes of refined petroleum products including gasoline, diesel and jet fuel.

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.

In September 2022, the Company completed the divestiture of the majority of the retail fuels business. As a result, Management elected to aggregate the remaining commercial fuels business and the historical retail fuels business into the Canadian Manufacturing segment. The marketing operations of the Canadian Manufacturing segment have similar products and services, customer types, distribution methods and operate in the same regulatory environment as the commercial fuels business. The commercial fuels business includes cardlock, bulk plant and travel centre locations across Canada. Comparative periods have been re-presented to reflect this change.

YEAR IN REVIEW

In 2022, we continued to focus on health and safety and drive competitive cost structures. High commodity prices in both our upstream and downstream businesses combined with solid upstream operating performance and good operating performance in our operated downstream assets drove strong financial results and allowed us to significantly reduce our total debt. We optimized our asset portfolio as we closed the acquisition of Sunrise and announced the acquisition of Toledo, which will provide us full ownership and operatorship of both assets. In addition, we completed the restructuring of our Atlantic assets and reached an agreement with our partners to restart the West White Rose project. We also sold our Tucker, Wembley and retail assets. These transactions enhanced Cenovus's core strength in the oil sands and will further optimize margins through increased physical integration of our upstream and downstream assets. Lastly, we improved our shareholder value proposition through an updated shareholder returns and capital allocation framework. The framework returns incremental value back to shareholders through share buybacks and/or variable dividends.

Summary of Annual Results

($ millions, except where indicated)	2022	Percent Change	2021	Percent Change	2020
Upstream Production Volumes [1] (MBOE/d)	**786.2**	**(1)**	791.5	68	471.7
Downstream Crude Oil Throughput [2] (Mbbls/d)	**493.7**	**(3)**	508.0	173	185.9
Revenues [3]	**66,897**	**44**	46,357	242	13,543
Operating Margin [4]	**14,263**	**52**	9,373	918	921
Cash From (Used In) Operating Activities	**11,403**	**93**	5,919	2,068	273
Adjusted Funds Flow [4]	**10,978**	**51**	7,248	6,095	117
Per Share – Basic [4] ($)	**5.63**	**57**	3.59	3,490	0.10
Per Share – Diluted [4] ($)	**5.47**	**55**	3.54	3,440	0.10
Capital Investment	**3,708**	**45**	2,563	205	841
Free Funds Flow [4]	**7,270**	**55**	4,685	N/A	(724)
Net Earnings (Loss) [5]	**6,450**	**999**	587	N/A	(2,379)
Per Share – Basic ($)	**3.29**	**1,119**	0.27	N/A	(1.94)
Per Share – Diluted ($)	**3.20**	**1,085**	0.27	N/A	(1.94)

(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) Prior period results have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.
(4) Non-GAAP financial measures or contains a non-GAAP financial measure. See the Advisory.
(5) Net earnings (loss) for all periods in the table above is the same as net earnings (loss) from continuing operations.

Summary of Annual Results

($ millions, except where indicated)	2022	Percent Change	2021	Percent Change	2020
Total Assets	**55,869**	**3**	54,104	65	32,770
Total Long-Term Liabilities	**20,259**	**(13)**	23,191	69	13,704
Long-Term Debt, Including Current Portion	**8,691**	**(30)**	12,385	66	7,441
Net Debt	**4,282**	**(55)**	9,591	34	7,184
Cash Returns to Shareholders					
Common Shares – Base Dividends	**682**	**288**	176	129	77
Base Dividends Per Common Share ($)	**0.350**	**298**	0.088	40	0.063
Common Shares – Variable Dividends	**219**	**N/A**	—	—	—
Variable Dividends Per Common Share ($)	**0.114**	**N/A**	—	—	—
Purchase of Common Shares Under NCIB	**2,530**	**855**	265	N/A	—
Preferred Share Dividends	**26**	**(24)**	34	N/A	—

In 2022, we delivered on our strategy through five key strategic objectives:

Top Tier Safety Performance and Sustainability Leadership

Underpinning everything we do is the safety of our people and communities, and the integrity of our assets. Safety, asset integrity and corporate governance are foundational to our business, and are the backbone for all of our operations. We promote a safety culture in all aspects of our work and use a variety of programs to always keep safety top of mind. In 2022, we:

- Delivered safe operations at our operated assets.
- Completed planned turnarounds at the operated Lloydminster Upgrader (the "Upgrader") and Lloydminster Refinery in our downstream operations. In addition, we completed a planned turnaround at Christina Lake in our upstream operations in the second quarter.
- Completed planned turnarounds at the non-operated Toledo, Wood River and Borger refineries in our downstream operations.
- Continued our focus on achieving our targets in each of our five Environmental, Social and Governance ("ESG") focus areas. Additional information on management's efforts and performance across ESG topics, including our ESG targets and plans to achieve them, are available in Cenovus's 2021 ESG report at cenovus.com.
- Actively participated in industry collaborations including the Pathways Alliance.

We continue to work with our partners of our non-operated downstream assets to improve the safety performance.

Competitive Cost Structures and Optimizing Margins

In 2022, we:

- Targeted additional cost savings and margin enhancements through further physical integration of upstream assets with downstream assets, which shortened the value chain and reduced condensate costs associated with heavy oil transportation.
- Improved efficiencies across Cenovus to drive incremental capital, operating, and general and administrative cost reductions.

Maintaining and Further Reducing Debt Levels

In 2022, we generated cash from operating activities of $11.4 billion and Free Funds Flow of $7.3 billion, enabling us to substantially decrease Net Debt.

- As at December 31, 2022, our long-term debt, including current portion, was $8.7 billion (December 31, 2021 – $12.4 billion) and our Net Debt position was $4.3 billion (December 31, 2021 – $9.6 billion).
- We deleveraged our balance sheet by purchasing US$2.6 billion in principal of notes due between 2023 and 2043, and $750 million in principal of notes due in 2025.
- Our Net Debt to Adjusted EBITDA Ratio was 0.3 times and our Net Debt to Adjusted Funds Flow Ratio was 0.4 times at December 31, 2022.

Growing Free Funds Flow Through Pricing Cycles

Our top-tier assets and low-cost structure position us to grow Free Funds Flow through pricing cycles. Cenovus's diversified asset and product mix generates predictable and stable Free Funds Flow and reduces risk and cash flow volatility by leveraging pipelines, logistics and marketing to optimize the value chain. We are able to generate strong margins with modest capital investment.

In 2022, we generated cash from operating activities of $11.4 billion and Free Funds Flow of $7.3 billion, primarily due to high commodity prices combined with solid upstream operating performance. WTI averaged approximately US$94 per barrel in 2022, the highest annual average since 2013, and an increase of approximately 40 percent from 2021. North American market crack spreads also reached historic highs during the year.

In 2022, we continued to optimize our top-tier asset portfolio and grow Free Funds Flow.

In our upstream business:

- We sold our Tucker asset and our Wembley assets for total net proceeds of $951 million.
- We reached an agreement with our partners to restart the West White Rose project in the Atlantic region offshore Newfoundland and Labrador. Major construction is expected to restart in the first quarter of 2023.
- We acquired the remaining 50 percent interest in Sunrise (the "Sunrise Acquisition") from BP Canada Energy Group ULC ("BP Canada") for net proceeds of $394 million, a variable payment with a maximum cumulative value of $600 million expiring in eight quarters subsequent to August 31, 2022, and our 35 percent position in the undeveloped Bay du Nord project offshore Newfoundland and Labrador.
- We achieved first oil at our Spruce Lake North thermal plant in the third quarter of 2022.
- In Indonesia, we achieved first gas production from the MBH and MDA fields in the fourth quarter of 2022.
- Received regulatory approval in December 2022 to develop the Ipiatik asset in the Foster Creek area.

In our downstream business:

- We announced an agreement to purchase the remaining 50 percent interest in the Toledo Refinery from BP (the "Toledo Acquisition"). The transaction is expected to close at the end of February 2023.
- We closed the sale of 337 gas stations within our retail fuels network for net cash proceeds of $404 million.

In addition, we sold our investment in Headwater Exploration Inc. for proceeds of $110 million.

Returns-focused Capital Allocation

The Company's sustaining capital program and base dividend are sustainable at US$45 WTI per barrel and provide opportunities to sustainably grow shareholder returns. In 2022:

- We renewed our NCIB, which expired on November 8, 2022. Under our new NCIB (the "2023 NCIB"), we are authorized to purchase up to 136.7 million of the Company's common shares between November 9, 2022, and November 8, 2023.
- We purchased and cancelled 112 million common shares for $2.5 billion through our NCIBs in 2022.
- We returned $901 million to common shareholders through base dividends of $0.350 per common share and variable dividends of $0.114 per common share.

We declared dividends for the first quarter of 2023:

- On February 15, 2023, the Board declared a first quarter base dividend of $0.105 per common share payable on March 31, 2023, to common shareholders of record as at March 15, 2023.
- On February 15, 2023, the Board declared first quarter dividends for our preferred shares of $9 million, payable on March 31, 2023, to preferred shareholders of record as at March 15, 2023.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results — Upstream

	2022	Percent Change	2021	Percent Change	2020
Upstream Production Volumes by Segment [1] (MBOE/d)					
Oil Sands	**588.7**	**1**	583.6	53	381.7
Conventional	**127.2**	**(5)**	133.6	49	89.9
Offshore	**70.3**	**(6)**	74.4	N/A	—
Total Production Volumes	**786.2**	**(1)**	791.5	68	471.7
Upstream Production Volumes by Product					
Bitumen (Mbbls/d)	**570.3**	**2**	561.3	47	381.7
Heavy Crude Oil (Mbbls/d)	**16.3**	**(19)**	20.2	648	2.7
Light Crude Oil (Mbbls/d)	**19.1**	**(15)**	22.5	400	4.5
NGLs (Mbbls/d)	**36.2**	**(5)**	38.3	96	19.5
Conventional Natural Gas (MMcf/d)	**866.1**	**(3)**	895.5	136	379.0
Total Production Volumes (MBOE/d)	**786.2**	**(1)**	791.5	68	471.7
Total Upstream Sales Volumes [2] (MBOE/d)	**696.4**	**(1)**	700.8	67	420.5
Netback [3][4] ($/BOE)	**53.21**	**44**	37.04	267	10.09
Oil and Gas Reserves (MMBOE)					
Total Proved	**6,082**	**—**	6,077	21	5,030
Probable	**2,787**	**27**	2,201	33	1,656
Total Proved Plus Probable	**8,869**	**7**	8,278	24	6,686

(1) Refer to the Oil Sands, Conventional or Offshore Operating Results 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 520 MMcf per day for the year ended December 31, 2022 (517 MMcf per day for the year ended December 31, 2021).
(3) Upstream revenue as found in Note 1 of the Consolidated Financial Statements was $36.3 billion for the year ended December 31, 2022 ($25.4 billion for the year ended December 31, 2021).
(4) Contains a non-GAAP financial measure. See the Advisory.

In 2022, total crude oil, NGLs and natural gas production was consistent with 2021. The factors below increased production in 2022 compared with 2021:

- New wells coming online at Foster Creek and Christina Lake in 2022 and the second half of 2021.
- The Sunrise Acquisition on August 31, 2022.
- First oil at the Spruce Lake North thermal plant in the third quarter of 2022.
- A planned turnaround and operational outages at Foster Creek in the second quarter of 2021.
- First gas production at the MBH and MDA fields in Indonesia in the fourth quarter of 2022.

The factors below decreased production in 2022 compared with 2021:

- The disposition of the Tucker asset on January 31, 2022.
- Planned maintenance and an unplanned outage at Foster Creek in the third quarter of 2022.
- Planned turnaround activity at Christina Lake in the second quarter of 2022.
- The disposition of the Wembley asset on February 28, 2022, and the East Clearwater and Kaybob divestitures in the second half of 2021.
- As part of the decision to restart the West White Rose project, we transferred a 12.5 percent working interest in the White Rose field and satellite extensions to our partner on May 31, 2022.

Oil and Gas Reserves

Based on our reserves reports prepared by independent qualified reserves evaluators ("IQREs"), total proved reserves and total proved plus probable reserves at December 31, 2022 were approximately 6.1 billion BOE and 8.9 billion BOE, respectively. Total proved reserves were consistent with 2021, and proved plus probable reserves increased seven percent compared with 2021.

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

Selected Operating Results — Downstream

	2022	Percent Change	2021	Percent Change	2020
Downstream Crude Oil Throughput (Mbbls/d)					
Canadian Manufacturing	**92.9**	**(13)**	106.5	N/A	—
U.S. Manufacturing	**400.8**	**—**	401.5	116	185.9
Total Throughput	**493.7**	**(3)**	508.0	173	185.9
Fuel Sales [(1)] (millions of litres/d)	**6.2**	**(10)**	6.9	N/A	—

(1) On September 13, 2022, we closed the sale of 337 gas stations within our retail fuels network. We retained our commercial fuels business, which includes cardlock, bulk plant and travel centre locations.

In the Canadian Manufacturing segment, throughput decreased 13.6 thousand barrels per day in 2022 compared with 2021. We completed planned turnarounds at both the Lloydminster Upgrader and Lloydminster Refinery in the second quarter of 2022. In addition, there were multiple temporary unplanned outages at the Upgrader in 2022. In 2021, the Upgrader and Lloydminster Refinery ran at or near capacity throughout the year.

In the U.S. Manufacturing segment, total throughput was consistent in 2022 compared with 2021:

- The Lima Refinery had unplanned operational issues in the first quarter of 2022 coming out of the 2021 fourth quarter turnaround. The refinery performed well during the remainder of the year, achieving crude utilization of 90 percent in 2022.
- At the Toledo Refinery, we completed a significant planned turnaround from April to early August 2022. The refinery remains shut down in a safe state following an incident on September 20, 2022.
- We completed two planned turnarounds at the Wood River Refinery in the second and fourth quarters of 2022. The second quarter turnaround was delayed due to cold weather, resulting in labour shortages and cost overruns. In early December, there was an incident at the Wood River Refinery that resulted in damage to one of the units and reduced throughput.
- We completed a turnaround at the Borger Refinery in the first and second quarter of 2022. In addition, the refinery had unplanned operational outages in the fourth quarter of 2022.
- We commenced commissioning for the restart of the Superior Refinery in December 2022.

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.

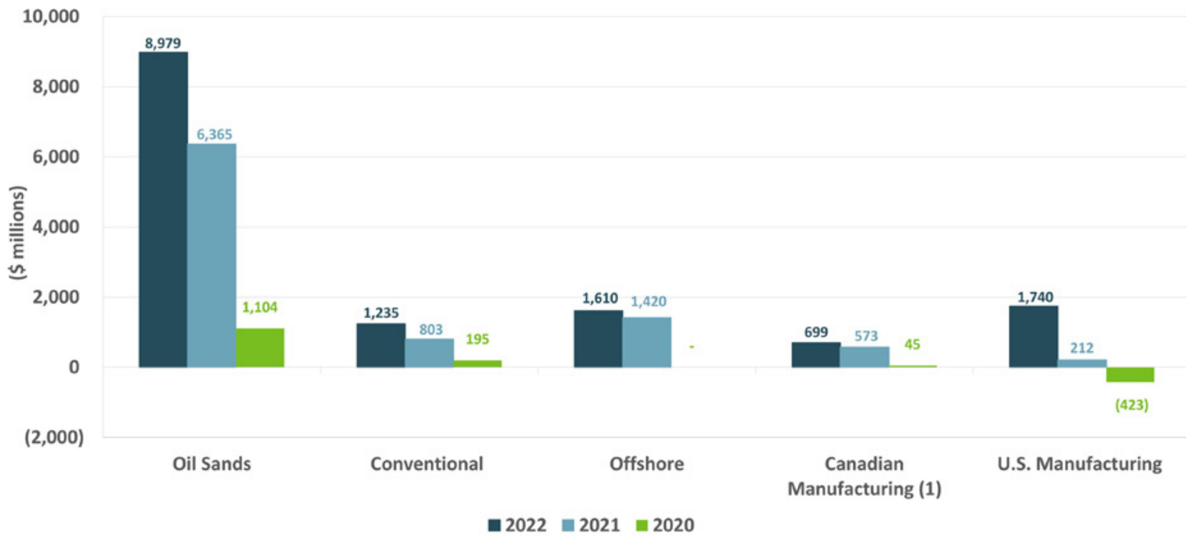
($ millions)	2022	2021 [(1)(2)]	2020
Gross Sales	**79,229**	54,102	14,523
Less: Royalties	**4,868**	2,454	371
Revenues	**74,361**	51,648	14,152
Expenses			
Purchased Product	**39,334**	27,170	5,959
Transportation and Blending	**12,194**	8,714	4,764
Operating Expenses	**6,839**	5,499	2,261
Realized (Gain) Loss on Risk Management Activities	**1,731**	892	247
Operating Margin	**14,263**	9,373	921

(1) Prior period results have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.

(2) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details. There has been no change to total Operating Margin.

Operating Margin by Segment

Year Ended December 31, 2022



(1) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuel business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details.

Operating Margin increased in 2022, mainly due to higher average realized sales prices, resulting from higher benchmark pricing. In addition, realized refining margins almost doubled in our downstream business due to significantly higher market crack spreads from 2021.

These increases in Operating Margin were partially offset by:

- Increased blending costs due to higher condensate prices.
- Higher royalties and fuel costs in our upstream operations, both resulting from significantly higher commodity pricing.
- Increased realized risk management losses on the settlement of benchmark prices relative to our risk management contract prices in 2022. In the second quarter of 2022, all WTI risk management contracts related to our crude oil sales price risk management activities were closed.
- Planned turnarounds and unplanned outages in our downstream operations in 2022, which impacted sales volumes and operating expenses.
- In our realized margin, higher Renewable Identification Numbers ("RINs") costs impacting our U.S. Manufacturing segment.
- Increased transportation costs due to increased tariffs combined with higher sales volumes at Foster Creek, Christina Lake and Sunrise.
- Higher operating expenses at the Superior Refinery. Costs increased compared with 2021 as we prepared for restart.
- Increased electricity and chemical costs in our upstream operations.

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

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

($ millions)	**2022**	2021	2020
Cash From (Used in) Operating Activities	**11,403**	5,919	273
(Add) Deduct:			
Settlement of Decommissioning Liabilities	**(150)**	(102)	(42)
Net Change in Non-Cash Working Capital	**575**	(1,227)	198
Adjusted Funds Flow	**10,978**	7,248	117

Cash from operating activities and Adjusted Funds Flow were higher in 2022, primarily due to:

- Increased Operating Margin, as discussed above.
- Lower finance costs which decreased $262 million in 2022 compared with 2021, primarily due to long-term debt purchases in 2021 and 2022.
- Decreased integration and transaction costs, a decline of $243 million in 2022 compared with 2021. The integration of Cenovus and Husky is substantially complete.

The increase was partially offset by higher cash taxes and higher quarterly contingent payments in 2022.

Cash from operating activities also increased as the net change in non-cash working capital increased by $1.8 billion compared to 2021. The increase was due to higher income tax payable and lower accounts receivable, offset by higher inventory at December 31, 2022 compared with December 31, 2021.

Net Earnings (Loss)

($ millions)	**2022 vs. 2021**	2021 vs. 2020
Net Earnings (Loss), Comparative Year	**587**	(2,379)
Increase (Decrease) due to:		
Operating Margin	**4,890**	8,452
Corporate and Eliminations:		
General and Administrative	**(16)**	(557)
Finance Costs	**262**	(546)
Integration and Transaction Costs	**243**	(320)
Unrealized Foreign Exchange Gain (Loss)	**(677)**	181
Revaluation Gains	**549**	—
Re-measurement of Contingent Payments	**413**	(655)
Gain (Loss) on Divestiture of Assets	**40**	148
Other Income (Loss), net	**223**	349
Other (1)	**308**	(194)
Unrealized Risk Management Gain (Loss)	**57**	36
Depreciation, Depletion and Amortization	**1,207**	(2,422)
Exploration Expense	**(83)**	73
Income Tax Recovery (Expense)	**(1,553)**	(1,579)
Net Earnings (Loss), Current Year	**6,450**	587

(1) Includes Corporate and Eliminations revenues, purchased product, transportation and blending, 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 improved significantly compared with 2021 due to:

- Increased Operating Margin, as discussed above.
- Net impairment charges in the fourth quarter of 2022 of $266 million, compared with net impairment charges of $1.6 billion in the fourth quarter of 2021.
- Revaluation gains of $549 million related to the Sunrise Acquisition in the third quarter of 2022.
- A loss on re-measurement of the contingent payments of $162 million compared with $575 million in 2021. The final payment related to the FCCL Partnership was made in July 2022. Re-measurements related to the Sunrise Acquisition began in the third quarter of 2022.
- Finance costs of $820 million compared with $1.1 billion in 2021, mainly due to a lower average long-term debt balance in 2022.
- Integration and transaction costs of $106 million, compared with $349 million in 2021.
- Higher other income primarily due to insurance proceeds related to the Superior Refinery.
- A realized foreign exchange gain of $22 million in 2022 compared to realized foreign exchange losses of $138 million in 2021. The gains in 2022 related to working capital were partially offset by losses on the purchase of debt.

The increase in net earnings in 2022 was partially offset by:

- Higher income tax expense.
- Unrealized foreign exchange losses as the Canadian dollar at December 31, 2022, weakened relative to the U.S. dollar.

Net Debt

As at ($ millions)	**December 31, 2022**	December 31, 2021
Short-Term Borrowings	**115**	79
Current Portion of Long-Term Debt	**—**	—
Long-Term Debt	**8,691**	12,385
Total Debt	**8,806**	12,464
Less: Cash and Cash Equivalents	**(4,524)**	(2,873)
Net Debt	**4,282**	9,591

Long-term debt decreased by $3.7 billion and Net Debt decreased by $5.3 billion from December 31, 2021. In 2022, we purchased US$2.6 billion of principal related to notes due between 2023 and 2043, and paid a premium on redemption of US$41 million, collectively. In addition, we paid $750 million to purchase the full principal amount outstanding of our 3.55 percent unsecured notes due in 2025 at par. The decrease in long-term debt was partially offset as the Canadian dollar weakened relative to the U.S. dollar on December 31, 2022, impacting our U.S. dollar debt.

Capital Investment (1)

($ millions)	**2022**	2021	2020
Upstream			
Oil Sands	**1,792**	1,019	427
Conventional	**344**	222	78
Offshore	**310**	175	—
Total Upstream	**2,446**	1,416	505
Downstream			
Canadian Manufacturing (2)	**117**	68	33
U.S. Manufacturing	**1,059**	995	243
Total Downstream	**1,176**	1,063	276
Corporate and Eliminations	**86**	84	60
Total Capital Investment	**3,708**	2,563	841

(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.

(2) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details.

Oil Sands capital investment in 2022 was primarily focused on 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 2022 focused on drilling, completion and tie-in activities, and infrastructure projects to support multi-year development.

Offshore capital investment in 2022 was primarily for the Terra Nova asset life extension ("ALE") project and capital for the West White Rose project in the Atlantic region. On May 31, 2022, Cenovus and our partners announced the restart of the West White Rose project offshore Newfoundland and Labrador.

U.S. Manufacturing capital investment in 2022 focused primarily on the Superior Refinery rebuild, and refining reliability initiatives at the Wood River, Borger and Toledo refineries, and yield optimization projects at the Wood River Refinery.

Drilling Activity

	Net Stratigraphic Test Wells and Observation Wells			**Net Production Wells** (1)		
	2022	2021	2020	**2022**	2021	2020
Foster Creek (2)	**68**	32	38	**29**	6	—
Christina Lake (3)	**—**	25	117	**31**	18	—
Sunrise	**15**	—	—	**10**	2	—
Lloydminster Thermal	**98**	115	—	**33**	46	—
Lloydminster Conventional Heavy Oil	**8**	15	—	**11**	3	—
Tucker (4)	**6**	—	—	**—**	—	—
	195	187	155	**114**	75	—

(1) SAGD well pairs in the Oil Sands segment are counted as a single producing well.

(2) Includes Ipiatik.

(3) Includes Narrows Lake.

(4) The Tucker asset was 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.

	2022			2021			2020		
(net wells)	**Drilled**	**Completed**	**Tied-in**	Drilled	Completed	Tied-in	Drilled	Completed	Tied-in
Conventional	**31**	**35**	**36**	27	19	18	6	1	3

In the Offshore segment, we drilled and completed nine (3.6 net) planned development wells at the MBH, MDA and MAC fields in Indonesia in 2022 (2021 — drilled one exploration well in China). We achieved first gas production at the MBH and MDA fields in the fourth quarter of 2022.

Future Capital Investment

Future Capital Investment is a specified financial measure. See the Advisory. Our 2023 guidance dated December 5, 2022, is available on our website at cenovus.com.

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**	**65 - 78**	
Downstream	**800 - 900**		**610 - 660**
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.

Sustaining capital is mainly related to:

- Investment in the Oil Sands segment.
- Safety and reliability initiatives in the Canadian Manufacturing segment.
- The planned restart of the Superior Refinery.
- Offsetting natural declines and optimizing gas handling infrastructure in the Conventional segment.

Optimization and growth capital including downstream initiatives that will further mitigate the Company's exposure to light-heavy differentials. Optimization and growth capital is mainly related to:

- Construction of the West White Rose project and the completion of the Terra Nova ALE project.
- Progressing the Narrows Lake tie-back to Christina Lake.
- Continued optimization of Foster Creek and the Lloydminster thermal projects.
- Application of Cenovus's operating model at Sunrise.
- Margin expansion and debottlenecking opportunities in our downstream assets, which include feedstock replacement at the Lloydminster Refinery as part of the Company's Rewire Alberta initiative.
- Increasing heavy crude oil conversion capacity and distillate output at the Wood River and Borger refineries.

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 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$/bbl, unless otherwise indicated)	2022	Percent Change	2021	2020	Q4 2022	Q4 2021
Dated Brent	**101.19**	**43**	70.73	41.67	**88.71**	79.73
WTI	**94.23**	**39**	67.91	39.40	**82.65**	77.19
Differential Dated Brent-WTI	**6.96**	**147**	2.82	2.27	**6.06**	2.54
WCS at Hardisty	**76.01**	**39**	54.87	26.80	**56.99**	62.55
Differential WTI-WCS	**18.22**	**40**	13.04	12.60	**25.66**	14.64
WCS (C$/bbl)	**98.51**	**43**	68.73	35.59	**77.42**	78.71
WCS at Nederland	**85.77**	**34**	64.09	35.86	**67.65**	71.62
Differential WTI-WCS at Nederland	**8.46**	**121**	3.82	3.54	**15.00**	5.57
Condensate (C5 @ Edmonton)	**93.78**	**38**	68.20	37.16	**83.40**	79.13
Differential WTI-Condensate (Premium)/Discount	**0.45**	**N/A**	(0.29)	2.24	**(0.75)**	(1.94)
Differential WCS-Condensate (Premium)/Discount	**(17.77)**	**(33)**	(13.33)	(10.36)	**(26.41)**	(16.58)
Average (C$/bbl)	**121.78**	**42**	85.47	49.44	**113.25**	99.64
Synthetic @ Edmonton	**98.66**	**49**	66.28	36.25	**86.79**	75.40
Differential WTI-Synthetic (Premium)/Discount	**(4.43)**	**N/A**	1.63	3.15	**(4.14)**	1.79
Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**120.63**	**42**	85.07	45.24	**102.80**	91.84
Chicago Ultra-low Sulphur Diesel ("ULSD")	**143.85**	**67**	86.37	50.08	**140.95**	96.53
Refining Benchmarks						
Chicago 3-2-1 Crack Spread [(2)]	**34.15**	**95**	17.54	7.54	**32.87**	16.06
Group 3 3-2-1 Crack Spread [(2)]	**33.21**	**86**	17.82	8.67	**29.99**	15.82
Renewable Identification Numbers ("RINs")	**7.72**	**14**	6.76	2.48	**8.54**	6.11
Natural Gas Prices						
AECO (C$/Mcf)	**5.56**	**56**	3.56	2.24	**5.58**	4.94
NYMEX (US$/Mcf)	**6.64**	**73**	3.84	2.08	**6.26**	5.83
Foreign Exchange Rates						
US$ per C$1 - Average	**0.769**	**(4)**	0.798	0.746	**0.737**	0.794
US$ per C$1 - End of Period	**0.738**	**(6)**	0.789	0.785	**0.738**	0.789
RMB per C$1 - Average	**5.170**	**—**	5.147	5.147	**5.241**	5.073

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

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

Crude Oil and Condensate Benchmarks

In 2022, global crude oil prices improved significantly compared to 2021. Prices rose steadily through 2021 and during the first half of 2022 as global supply and demand balances remained tight, while inventories were low. Demand for crude oil and refined products continued to grow towards pre-pandemic levels despite macroeconomic challenges, weakness in Chinese consumption due to COVID-19 lockdowns, and geopolitical uncertainty around Russia's invasion of Ukraine. Crude oil supply grew considerably in 2022 but struggled to match growing demand, with nearly all short-term supply sources accessed to meet demand, including unprecedented releases of U.S. government strategic petroleum reserves ("SPRs"). Global spare production capacity remains low.

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

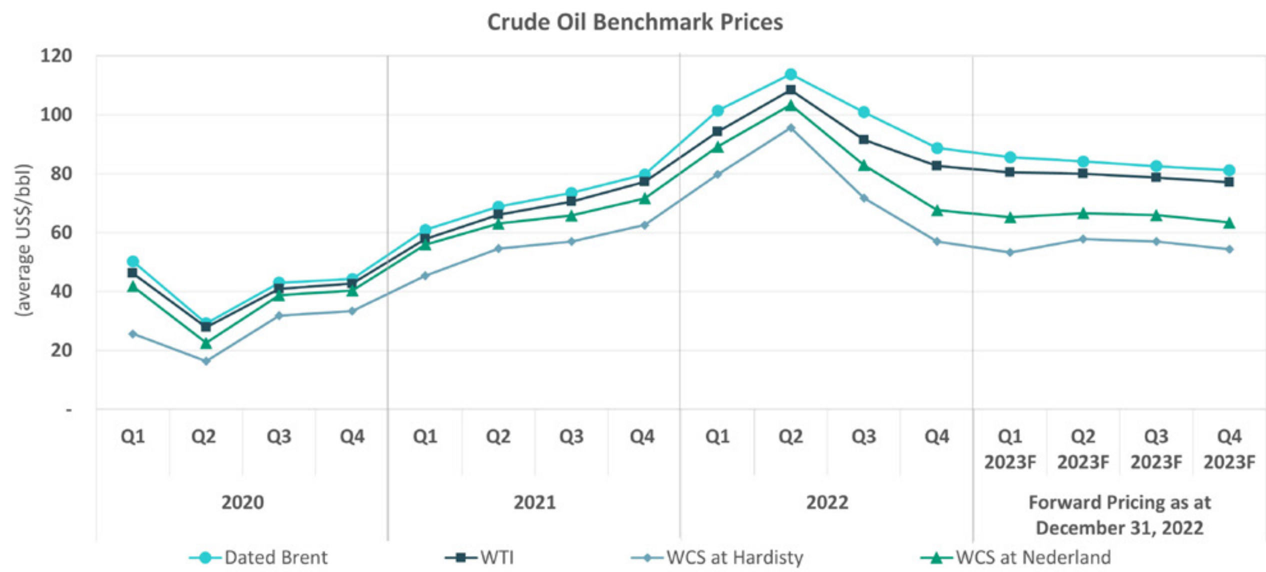
The price received for our Atlantic crude oil and Asia Pacific NGLs is primarily driven by the price of Brent. The Brent-WTI differential widened compared with 2021 due to higher shipping costs and supply disruptions as a result of Russia's invasion of Ukraine.

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 2022, the average WTI-WCS differential at Hardisty widened compared to 2021, 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 compared with 2021, particularly in the second half of 2022. It is 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 some incremental medium and heavy oil barrels into the market from OPEC+, and from the release of volume from SPRs in the U.S.

In Canada, we upgrade heavy crude oil and bitumen into a sweet synthetic crude oil, the Husky Synthetic Blend ("HSB"), at the Lloydminster 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.

Synthetic crude at Edmonton strengthened significantly in 2022 compared with 2021 as a result of widespread upgrader maintenance in Western Canada and strong refinery demand for light crude oil. In 2022, the WTI-Synthetic differential was at a premium compared with a discount in 2021 as synthetic crudes continue to be supported by strong demand for refined products.



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 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 benchmark remained near parity with WTI in 2022 as Alberta demand for condensate is strong and supply remains tight.

Refining Benchmarks

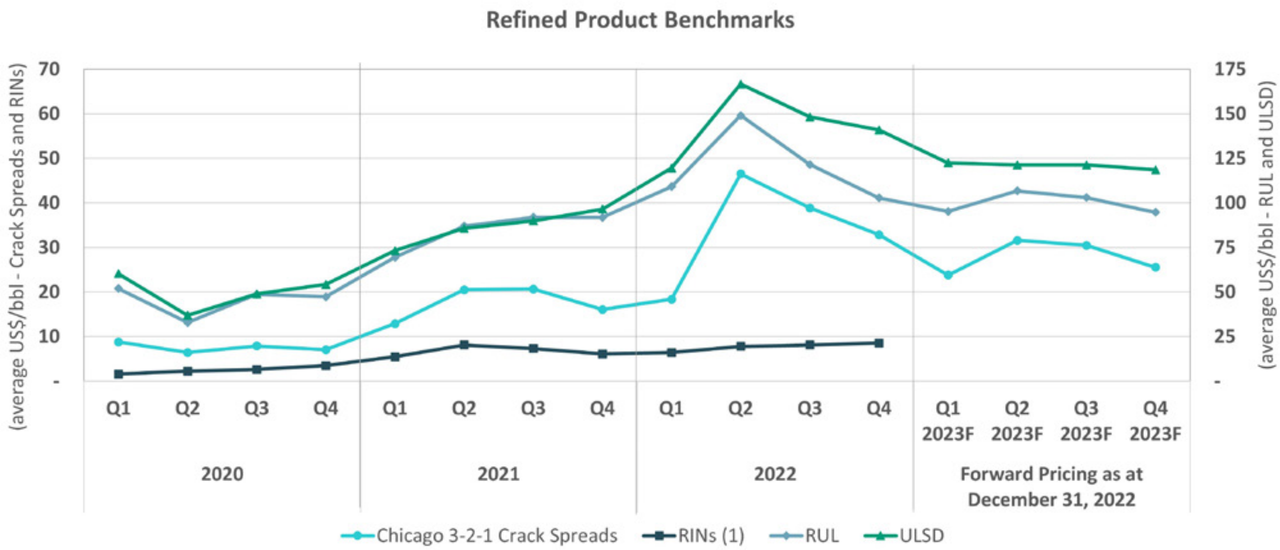
RUL and ULSD benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 market crack spread. The 3-2-1 market crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded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

Average Chicago refined product prices increased significantly in 2022 compared with 2021. While gasoline prices strengthened year-over-year, the increase in market crack spreads were primarily driven by a substantial rise in distillate prices. The strength in market crack spreads and refined product prices has also been driven by refinery rationalization since the beginning of the pandemic, leading to high refinery utilization globally, combined with low global inventories of refined products. 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 increased significantly in 2022, compared with 2021, due to a rebound in U.S. domestic demand and high liquified natural gas exports, coupled with a muted supply response and strong global pricing amid Russian supply concerns. Average AECO prices also increased significantly in 2022 compared with 2021 along with NYMEX prices, but the differentials between AECO and NYMEX widened slightly due to higher Western Canadian production as well as planned and unplanned pipeline maintenance limiting egress at points during 2022. 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 2022, the Canadian dollar on average weakened relative to the U.S. dollar compared with 2021, positively impacting our revenues year-over-year. The Canadian dollar weakened relative to the U.S. dollar as at December 31, 2022, compared with December 31, 2021, resulting in unrealized foreign exchange losses of $365 million 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 2022, the Canadian dollar on average was relatively flat compared with RMB, resulting in minimal impact on our revenues year-over-year.

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 December 31, 2022, the Bank of Canada's Policy Interest Rate was 4.25 percent, an increase from 0.25 percent on December 31, 2021, due to concerns over inflation. On January 25, 2023, the rate increased a further 0.25 percent to 4.50 percent.

OUTLOOK

COMMODITY PRICE OUTLOOK

Crude oil prices improved significantly in 2022, but waned in the second half of the year due to demand concerns amid a weakening macroeconomic environment and COVID-19 lockdowns in China. 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 recent 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 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.
- We expect both NYMEX and AECO prices to remain strong but increasing supply and limited LNG export capacity from North America will put downward pressure on prices. Prices will continue to be impacted by weather.
- 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. 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.

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.

All WTI contracts related to our crude oil sales price risk management activities closed by June 30, 2022. We continue to use financial instruments to mitigate our exposure to the prices of various commodities, including some WTI contracts for exposure management unrelated to crude oil sales price risk management; and contracts for management of price exposures associated with crude oil, crude oil differentials, condensate, natural gas liquids, refined products, refining margins, natural gas, electricity and renewable power contracts.

KEY PRIORITIES FOR 2023

At Cenovus, our purpose is to energize the world to make people's lives better. Our strategy continues to focus on maximizing shareholder value through competitive cost structures and optimizing margins while delivering top-tier safety performance and sustainability leadership. We prioritize Free Funds Flow generation that enables debt reduction, shareholder returns through a combination of base dividend growth and flexible return mechanisms, reinvestment in the business and diversification of our portfolio.

Our 2023 priorities will focus on:

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 downstream operating performance, including the safe return of the Superior Refinery to full operations and, following the close of the Toledo Acquisition, 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 management's efforts and performance across 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 will be 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 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 while remaining on track to deliver first oil in 2026.

REPORTABLE SEGMENTS

UPSTREAM

Oil Sands

In 2022, we:

- Delivered safe and reliable operations.
- Produced 586.6 thousand barrels of crude oil per day.
- Generated Operating Margin of $9.0 billion, an increase of $2.6 billion compared with 2021 primarily due to higher average realized sales prices.
- Sold our Tucker asset for net proceeds of $730 million on January 31, 2022. Crude oil production at the time of sale was approximately 20 thousand barrels per day.
- Purchased the remaining 50 percent interest in Sunrise from BP Canada on August 31, 2022, giving Cenovus full ownership and further enhancing our core strength in oil sands. The Sunrise Acquisition immediately added over 20 thousand barrels per day of crude oil production, and more than offset lost production from the sold Tucker asset.
- Achieved first oil at our Spruce Lake North thermal plant in September. Production averaged approximately 12.0 thousand barrels per day in the fourth quarter.
- Received regulatory approval in December 2022 to develop the Ipiatik asset in the Foster Creek area. This is expected to provide future bitumen feedstock to the Foster Creek plant. Pad construction is expected to begin in 2024 and we anticipate first steam in 2029.
- Invested capital of $1.8 billion primarily on sustaining activities at Christina Lake, Foster Creek, the Lloydminster thermal assets and Sunrise.
- Achieved a Netback of $49.10 per BOE.

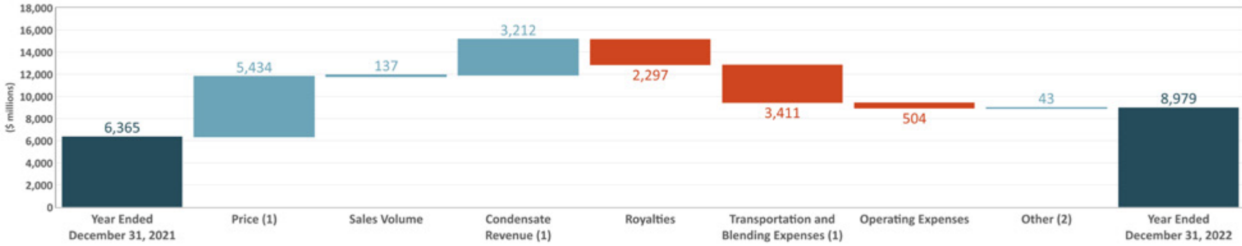
Financial Results

($ millions)	2022	2021 [1]	2020
Revenues			
Gross Sales	**34,775**	22,827	8,804
Less: Royalties	**4,493**	2,196	331
	30,282	20,631	8,473
Expenses			
Purchased Product	**4,810**	2,404	1,262
Transportation and Blending	**12,036**	8,625	4,683
Operating	**2,930**	2,451	1,156
Realized (Gain) Loss on Risk Management	**1,527**	786	268
Operating Margin	**8,979**	6,365	1,104
Unrealized (Gain) Loss on Risk Management	**(68)**	18	57
Depreciation, Depletion and Amortization	**2,763**	2,666	1,687
Exploration Expense	**9**	16	9
(Income) Loss from Equity-Accounted Affiliates	**8**	(5)	—
Segment Income (Loss)	**6,267**	3,670	(649)

(1) Prior period results have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.

Operating Margin Variance

Year Ended December 31, 2022



(1) Reported revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

(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

	2022	2021	2020
Total Sales Volumes (MBOE/d)	**585.8**	579.9	386.6
Total Realized Price (1) ($/BOE)	**91.70**	62.82	28.64
Crude Oil Production by Asset (Mbbls/d)			
Foster Creek	**191.0**	179.9	163.2
Christina Lake	**246.5**	236.8	218.5
Sunrise (2)	**31.3**	25.9	—
Lloydminster Thermal	**99.9**	97.7	—
Lloydminster Conventional Heavy Oil	**16.3**	20.2	—
Tucker (3)	**1.6**	21.0	—
Total Crude Oil Production (4) (Mbbls/d)	**586.6**	581.5	381.7
Natural Gas (5) (MMcf/d)	**12.3**	12.6	—
Total Production (MBOE/d)	**588.7**	583.6	381.7
Effective Royalty Rate (percent)	**25.2**	18.7	11.6
Transportation and Blending Cost (1) ($/BOE)	**7.89**	7.23	8.70
Operating Expense (1) ($/BOE)	**13.75**	11.52	7.84
Per Unit DD&A (1) ($/BOE)	**11.90**	11.28	10.40

(1) Specified financial measure. See the Advisory.

(2) Represents Cenovus's 50 percent interest in Sunrise up to August 31, 2022. On August 31, 2022, we acquired the remaining 50 percent interest 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. Up to three months may lapse from when we purchase condensate to when we sell our blended production.

Our realized sales price averaged $91.70 per BOE in 2022 compared with $62.82 per BOE in 2021 due to higher WTI benchmark prices, partially offset by wider WTI-WCS differentials. To improve our realized sales price, we sold approximately 20 percent (2021 – 20 percent) of our crude oil volumes at U.S. destinations.

For the year ended December 31, 2022, gross sales included $4.5 billion (2021 – $2.1 billion), from third-party sourced volumes which are not included in our realized price or our Netbacks. Refer to the Advisory for more detail.

For the year ended December 31, 2022, gross sales included $358 million (2021 – $329 million), relating to construction, transportation and blending activities. These amounts are not included in our realized price or our Netbacks. Refer to the Advisory 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 2022, we incurred realized risk management losses of $1.5 billion, of which $431 million related to the early liquidation of WTI positions in the second quarter. In 2022, we recorded unrealized risk management gains of $68 million on our crude oil and condensate financial instruments.

Production Volumes

Oil Sands crude oil production increased slightly to 586.6 thousand barrels per day in 2022 compared with 581.5 thousand barrels per day in 2021.

We sold the Tucker asset on January 31, 2022, resulting in decreased production of 19.4 thousand barrels per day in 2022 compared with 2021.

Production at Foster Creek increased 11.1 thousand barrels per day to 191.0 thousand barrels per day in 2022 compared with 2021, due to new wells coming online in 2022 and the last half of 2021. In addition, we completed a planned turnaround in the second quarter of 2021. The increase was partially offset as production reached peak levels in the fourth quarter of 2021 due to the timing of well pads starting up. Also offsetting the increase was planned maintenance and an unplanned outage in the third quarter of 2022.

Production at Christina Lake increased 9.7 thousand barrels per day to 246.5 thousand barrels per day in 2022 compared with 2021. We added incremental production from redevelopment wells drilled in 2022 and the last half of 2021. The increase was offset by a planned turnaround in the second quarter of 2022.

The Sunrise Acquisition was completed on August 31, 2022 and added 5.4 thousand barrels per day of production in 2022 compared with 2021. The increase in production at Sunrise in 2022 was partially offset by base declines and wells taken offline in preparation for a redevelopment program.

Production from our Lloydminster thermal assets increased slightly in 2022 compared with 2021. The Spruce Lake North thermal plant achieved first oil in August, and production averaged approximately 12.0 thousand barrels per day in the fourth quarter. The increase was partially offset by base declines at other thermal plants and wells taken offline in preparation for a redevelopment program in the fourth quarter of 2022 and into 2023.

Lloydminster conventional heavy oil production decreased marginally in 2022 compared with 2021, as wells were shut-in to meet new emissions regulations in Alberta.

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 increased primarily due to higher realized pricing and higher Alberta oil sands sliding scale royalty rates. For the year ended December 31, 2022, royalties were $4.5 billion (2021 – $2.2 billion).

Expenses

Transportation and Blending

In 2022, blending costs rose $3.2 billion to $10.3 billion compared with 2021. The increases were largely due to higher condensate prices.

Transportation costs increased $179 million to $1.7 billion in 2022 compared with 2021. The increases were primarily due to higher costs as discussed below combined with increased sales volumes at Foster Creek, Christina Lake and Sunrise.

Per-unit Transportation Expenses

Transportation costs were $7.89 per BOE in 2022 up slightly from $7.23 per BOE in 2021.

At Foster Creek, per-unit transportation costs increased 12 percent to $11.78 per barrel in 2022 compared with 2021. The increase was mainly due to increased tariffs, partially offset by reduced reliance on rail. For the year ended December 31, 2022, we shipped 40 percent (2021 – 35 percent), of our volumes from Foster Creek to U.S. destinations.

At Christina Lake, transportation costs were $6.51 per barrel in 2022, consistent with $6.19 per barrel in 2021.

At Sunrise, transportation costs were $12.26 per barrel in 2022, consistent with $12.14 per barrel in 2021, as we shipped a similar percentage of our total volumes to the U.S.

At our Other Oil Sands assets, transportation costs in 2022 were $3.49 per barrel, compared with $4.01 per barrel in 2021. In the first quarter of 2021, we stopped shipping volumes to U.S. destinations to optimize our pipeline capacity, reducing per-unit costs year-over-year.

Operating

Primary drivers of our operating expenses in 2022 were fuel, workforce, chemical, repairs and maintenance, and electricity costs. Total operating expenses increased largely due to higher fuel costs as a result of higher natural gas prices. AECO benchmark natural gas prices increased 56 percent in 2022 compared with 2021. In addition, total operating expenses increased due to higher electricity, repairs and maintenance and chemical costs. Chemical costs and electricity costs are also influenced by rising crude oil and natural gas benchmark prices. We have experienced minimal inflationary pressures on our costs, as we manage our costs by securing long-term contracts, working with vendors and purchasing long-lead items to mitigate future cost escalations.

Unit Operating Expenses (1)

($/BOE)	**2022**	**Percent Change**	2021	Percent Change	2020
Foster Creek					
Fuel	**6.07**	**49**	4.07	44	2.83
Non-Fuel	**6.52**	**(2)**	6.67	4	6.41
Total	**12.59**	**17**	10.74	16	9.24
Christina Lake					
Fuel	**5.07**	**44**	3.52	61	2.18
Non-Fuel	**4.87**	**3**	4.72	2	4.61
Total	**9.94**	**21**	8.24	21	6.79
Sunrise					
Fuel	**7.01**	**26**	5.58	—	—
Non-Fuel	**10.48**	**(9)**	11.57	—	—
Total	**17.49**	**2**	17.15	—	—
Other Oil Sands (2)					
Fuel	**7.35**	**50**	4.91	—	—
Non-Fuel	**15.10**	**29**	11.73	—	—
Total	**22.45**	**35**	16.64	—	—
Total	**13.75**	**19**	11.52	47	7.84

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

Per-unit fuel prices increased largely due to higher natural gas prices as discussed above.

Foster Creek per-unit non-fuel costs were consistent with 2021. Higher chemical, electricity and repairs and maintenance costs were offset by higher sales volumes.

Christina Lake per unit non-fuel costs were consistent with 2021. Higher electricity and repairs and maintenance costs were offset by higher sales volumes in 2022.

Sunrise per unit non-fuel costs decreased in 2022 compared with 2021. The decrease in non-fuel costs were primarily related to the planned turnaround costs in the second quarter of 2021, partially offset by higher electricity, chemical and workover costs in 2022.

Per-unit non-fuel costs at our Other Oil Sands assets increased in 2022 compared with 2021, primarily due to higher chemical and workover costs.

Netbacks

($/BOE)	**2022**	2021	2020
Sales Price [(1)]	**91.70**	62.82	28.64
Royalties [(1)]	**20.96**	10.38	2.34
Transportation [(1)]	**7.89**	7.23	8.70
Operating Expenses [(1)]	**13.75**	11.52	7.84
Netback [(2)]	**49.10**	33.69	9.76

(1) Specified financial measure. See the Advisory.
(2) Contains a non-GAAP financial measure. See the Advisory.

DD&A

In the year ended December 31, 2022, DD&A remained relatively consistent at $2.8 billion, compared with $2.7 billion in 2021. The average depletion rate for the year ended December 31, 2022, was $11.90 per BOE, compared with $11.28 per BOE in 2021.

Conventional

In 2022, we:

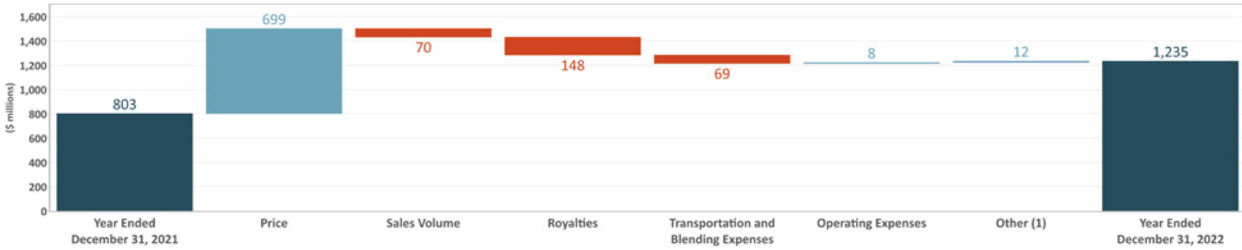
- Delivered safe and reliable operations.
- Sold our assets in the Wembley area for net proceeds of $221 million on February 28, 2022.
- Generated Operating Margin of $1.2 billion, an increase of $432 million compared with 2021, largely due to higher average realized sales prices.
- Invested capital of $344 million focused on drilling, completion and tie-in activities, and infrastructure projects to support multi-year development.
- Achieved a Netback of $27.43 per BOE.

Financial Results

($ millions)	**2022**	2021	2020
Revenues			
Gross Sales	**4,332**	3,235	904
Less: Royalties	**298**	150	40
	4,034	3,085	864
Expenses			
Purchased Product	**2,023**	1,655	268
Transportation and Blending	**143**	74	81
Operating	**541**	551	320
Realized (Gain) Loss on Risk Management	**92**	2	—
Operating Margin	**1,235**	803	195
Unrealized (Gain) Loss on Risk Management	**13**	1	—
Depreciation, Depletion and Amortization	**370**	3	880
Exploration Expense	**1**	(3)	82
Segment Income (Loss)	**851**	802	(767)

Operating Margin Variance

Year Ended December 31, 2022



(1) Reflects Operating Margin from processing facilities.

Operating Results

	2022	2021	2020
Total Sales Volumes (MBOE/d)	**127.2**	133.4	89.8
Total Realized Price [(1)] ($/BOE)	**48.15**	31.20	17.84
Heavy Crude Oil ($/bbl)	**—**	—	31.45
Light Crude Oil ($/bbl)	**118.64**	76.32	42.78
NGLs ($/bbl)	**63.22**	42.93	22.04
Conventional Natural Gas ($/Mcf)	**6.50**	4.07	2.37
Production by Product			
Heavy Crude Oil (Mbbls/d)	**—**	—	2.7
Light Crude Oil (Mbbls/d)	**7.5**	8.4	4.5
NGLs (Mbbls/d)	**23.8**	25.6	19.5
Conventional Natural Gas (MMcf/d)	**576.1**	597.6	379.0
Total Production (MBOE/d)	**127.2**	133.6	89.9
Conventional Natural Gas Production (percentage of total)	**75**	75	70
Crude Oil and NGLs Production (percentage of total)	**25**	25	30
Effective Royalty Rate (percent)	**15.4**	10.3	7.9
Transportation Costs [(1)] ($/BOE)	**3.16**	1.53	2.46
Operating Expense [(1)] ($/BOE)	**11.18**	10.66	8.99
Per Unit DD&A [(1)] ($/BOE)	**8.23**	9.11	9.85

(1) Specified financial measure. See the Advisory.

Revenues

Price

Our total realized sales price increased in 2022, due to higher crude oil and natural gas benchmark prices.

For the year ended December 31, 2022, gross sales included $2.0 billion (2021 – $1.7 billion), relating to third-party sourced volumes, which are not included in our realized prices or our Netbacks. See the Advisory for more detail.

For the year ended December 31, 2022, revenues included amounts relating to processing and transportation activities undertaken for third-parties of $71 million (2021 – $61 million), which are not included in our realized prices or our Netbacks. See the Advisory for more detail.

Production Volumes

Production volumes decreased 6.4 thousand BOE per day in 2022 compared with 2021, mainly due to asset sales in the first quarter of 2022 and the second half of 2021, and natural declines. The production decrease is partially offset by 36 net new wells (2021 – 18 net new wells) brought on production during the year, combined with production from well reactivations and workover activity.

Royalties

The Conventional assets are subject to royalty regimes in Alberta and British Columbia. Total royalties and effective royalty rates increased in 2022 compared with 2021, primarily due to higher realized pricing.

Expenses

Transportation

Our transportation costs reflect charges for the movement of crude oil, NGLs and natural gas from the point of production to where the product is sold. Transportation costs increased $69 million in 2022, compared with 2021. Per-unit transportation costs averaged $3.16 per BOE in 2022, compared with $1.53 per BOE in 2021.

Operating

Primary drivers of our operating expenses in 2022, were repairs and maintenance, workforce, electricity, property taxes and lease costs. Operating expenses per BOE in the year ended December 31, 2022, increased compared with 2021 primarily due to higher workover, energy and electricity costs, combined with lower sales volumes. Total operating expenses in 2022 were flat compared with 2021, due to the same factors that increased operating expenses per BOE, partially offset by asset sales in the first quarter of 2022 and the second half of 2021.

Netbacks

($/BOE)	2022	2021	2020
Sales Price (1)	**48.15**	31.20	17.84
Royalties (1)	**6.38**	3.06	1.23
Transportation and Blending (1)	**3.16**	1.53	2.46
Operating Expenses (1)	**11.18**	10.66	8.99
Netback (2)	**27.43**	15.95	5.16

(1) Specified financial measure. See the Advisory.
(2) Contains a non-GAAP financial measure. See the Advisory.

DD&A

For the year ended December 31, 2022, total Conventional DD&A was $370 million (2021 – $3 million). The increase was due to impairment reversals of $378 million in 2021.

The average depletion rate for 2022 was $8.23 per BOE (2021 – $9.11 per BOE). The average depletion rate excludes the impact of impairments and impairment reversals.

Offshore

In 2022, we:

- Delivered safe and reliable operations.
- Completed the dry-dock portion of the Terra Nova ALE project. We expect the Terra Nova field to resume production in the second quarter of 2023.
- Announced our decision to proceed with the completion of the West White Rose project.
- Sold our 35 percent position in the undeveloped Bay du Nord project offshore Newfoundland and Labrador as part of our consideration in the Sunrise Acquisition.
- Generated Operating Margin of $1.6 billion, an increase of $190 million compared with 2021, largely due to higher average realized sales prices, partially offset by increased operating expenses and lower sales volumes.
- Earned a Netback of $68.90 per BOE.
- Invested capital of $310 million mainly for the Terra Nova ALE and the West White Rose projects in the Atlantic region.

In September 2021, Cenovus announced an agreement with its partners to restructure its working interest in the Atlantic region and proceed with the ALE project for Terra Nova. The agreement increased Cenovus's working interest in Terra Nova to 34 percent from 13 percent and, pending a decision to restart the West White Rose Project, would decrease Cenovus's working interest in the White Rose field and satellite extensions by 12.5 percent.

On May 31, 2022, Cenovus and its partners announced the restart of the West White Rose project resulting in the 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 December 31, 2022, the project was around 65 percent complete. Since our decision to restart the project, we have invested approximately $85 million in 2022.

At our equity-accounted assets in Indonesia, we drilled and completed two MBH field development wells and five MDA field development wells planned for the year. We achieved first gas production from the MBH and MDA fields in the fourth quarter of 2022. In Indonesia we also have the MAC and MDK fields under development. At the MAC field, we drilled and completed two development wells in the fourth quarter of 2022, of the three planned at the field. We expect first gas production from the MAC and MDK fields by 2023 and 2025, respectively.

In China, we finalized an agreement in the second quarter 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 that temporarily increased sales volumes. In addition, in the first quarter we terminated the production sharing contract ("PSC") at Block 23/07, which was in the exploration phase, and never produced or had drilling activity.

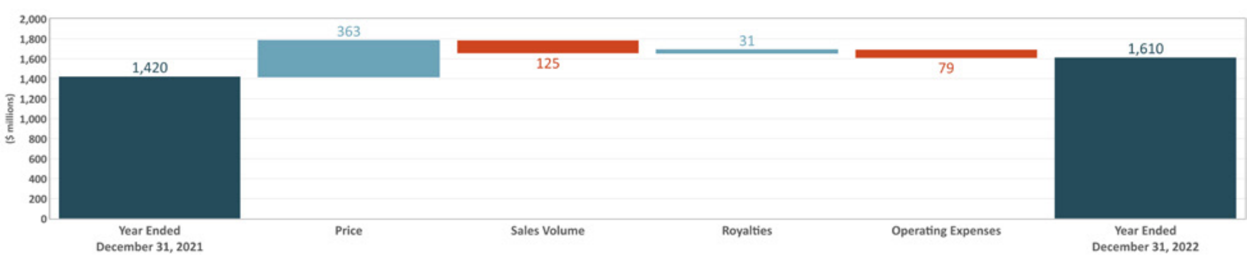
Financial Results

	2022			2021		
($ millions)	**Asia Pacific**	**Atlantic**	**Offshore**	Asia Pacific	Atlantic	Offshore
Revenues						
Gross Sales	**1,442**	**578**	**2,020**	1,342	440	1,782
Less: Royalties	**80**	**(3)**	**77**	79	29	108
	1,362	**581**	**1,943**	1,263	411	1,674
Expenses						
Transportation and Blending	**—**	**15**	**15**	—	15	15
Operating	**114**	**204**	**318**	103	136	239
Operating Margin (1)	**1,248**	**362**	**1,610**	1,160	260	1,420
Depreciation, Depletion and Amortization			**585**			492
Exploration Expense			**91**			5
(Income) Loss from Equity-Accounted Affiliates			**(23)**			(47)
Segment Income (Loss)			**957**			970

(1) *Asia Pacific and Atlantic Operating Margin are non-GAAP financial measures. See the Advisory.*

Operating Margin Variance

Year Ended December 31, 2022



Operating Results

	2022	2021
Total Sales Volumes (MBOE/d)	**70.0**	73.5
Atlantic	**11.3**	13.2
Asia Pacific [1]	**58.7**	60.3
Total Realized Price [2] ($/BOE)	**89.72**	74.75
Atlantic - Light Crude Oil ($/bbl)	**140.65**	91.01
Asia Pacific [1] ($/BOE)	**79.96**	71.19
NGLs ($/bbl)	**110.05**	79.83
Conventional Natural Gas ($/Mcf)	**11.98**	11.48
Production by Product		
Atlantic - Light Crude Oil (Mbbls/d)	**11.6**	14.1
Asia Pacific [1]		
NGLs (Mbbls/d)	**12.4**	12.7
Conventional Natural Gas (MMcf/d)	**277.7**	285.3
Asia Pacific Total (MBOE/d)	**58.7**	60.3
Total Production (MBOE/d)	**70.3**	74.4
Effective Royalty Rate (percent)		
Atlantic	**(0.5)**	6.7
Asia Pacific [1]	**11.5**	8.4
Operating Expense [2] ($/BOE)	**12.64**	9.86
Atlantic	**42.03**	28.34
Asia Pacific [1]	**7.00**	5.80
Per Unit DD&A [2] ($/BOE)	**30.76**	25.62

(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 Advisory.

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 increased in 2022 compared with 2021, primarily due to higher Brent benchmark pricing.

Production Volumes

Asia Pacific production decreased slightly in 2022 compared with 2021, due to changes to contracts at Liwan 3-1 and Liuhua 29-1 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.

Atlantic production decreased slightly in 2022 compared with 2021, due to the decrease in Cenovus's working interest at the White Rose field and satellite extensions in the second quarter of 2022. 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.

Royalties

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 2022 was 11.5 percent (2021 – 8.4 percent). The increase in the effective royalty rates in 2022 are due to the full recovery of development costs at the Madura-BD gas project in the third quarter of 2021.

Royalties at the White Rose fields are based on an amended agreement between our working interest partners and the Government of Newfoundland and Labrador. For 2022, retroactive to January 1, 2022, we paid a basic royalty of 1.0 percent of gross sales from the White Rose fields and 1.0 percent of gross sales from the satellite extensions. As a result, royalties were negative $3 million in 2022 (2021 – $29 million).

Expenses

Operating

Primary drivers of our Asia Pacific operating expenses in 2022 were repairs and maintenance, insurance and workforce. Total and per-unit operating expenses increased marginally year-over-year, primarily due to planned maintenance in China in the second and third quarter, combined with lower production in China. Also contributing to the increase in per-unit operating expenses were costs related to the MBH and MDA fields coming online in the fourth quarter of 2022.

Primary drivers of our Atlantic operating expenses in 2022 were vessel and helicopter costs, repairs and maintenance, and workforce. Total operating expenses increased mainly due to continued preparations for the Terra Nova FPSO's return to field and a higher working interest in the Terra Nova field. 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 lower sales volumes, combined with increased costs at Terra Nova discussed above.

Transportation

Transportation in the Atlantic region remained consistent year-over-year and include the cost of transporting crude oil from the SeaRose FPSO unit to onshore via tankers, as well as storage costs.

Netbacks

	2022			
($/BOE, except where indicated)	**China**	**Indonesia** [(1)]	**Atlantic** ($/bbl)	**Total Offshore**
Sales Price [(2)]	**81.99**	**70.66**	**140.65**	**89.72**
Royalties [(2)]	**4.57**	**30.19**	**(0.74)**	**7.57**
Transportation and Blending [(2)]	**—**	**—**	**3.79**	**0.61**
Operating Expenses [(2)]	**5.62**	**13.32**	**42.03**	**12.64**
Netback [(3)]	**71.80**	**27.15**	**95.57**	**68.90**

	2021			
($/BOE, except where indicated)	China	Indonesia [(1)]	Atlantic ($/bbl)	Total Offshore
Sales Price [(2)]	72.44	64.52	91.01	74.75
Royalties [(2)]	4.25	14.93	6.07	5.96
Transportation and Blending [(2)]	—	—	3.02	0.54
Operating Expenses [(2)]	5.10	9.55	28.34	9.86
Netback [(3)]	63.09	40.04	53.58	58.39

(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 Advisory.
(3) Contains a non-GAAP financial measure. See the Advisory.

DD&A

In 2022, total Offshore DD&A was $585 million (2021 – $492 million). The average depletion rate in 2022 was $30.76 per BOE, (2021 – $25.62 per BOE).

Exploration Expense

In 2022, we recorded exploration expense of $91 million, primarily due to a $58 million write-off related to our decision not to pursue development at Block 15/33 in China, penalties related to terminating the PSC at Block 23/07 in China and spending at Bay du Nord in the Atlantic region prior to its divestiture.

DOWNSTREAM

Canadian Manufacturing

In 2022, we:

- Delivered safe operations.
- Completed planned turnarounds at the Upgrader and Lloydminster Refinery in the second quarter.
- Averaged combined crude utilization of 84 percent at the Upgrader and Lloydminster Refinery. There were several unplanned outages, primarily at the Upgrader in 2022.
- Generated Operating Margin of $699 million, an increase of $126 million compared with 2021, primarily due to a higher upgrading differential, and higher distillate and asphalt pricing, partially offset by the impact of turnaround activities and unplanned outages on sales volumes and operating expenses.
- We closed the sales of 337 gas stations within our retail fuels network for net cash proceeds of $404 million.

Following the sale of the retail business, we retained our commercial fuels business, which at December 31, 2022, includes 170 cardlock, bulk plant and travel center locations. The commercial fuels business and historical retail fuels business are aggregated into the Canadian Manufacturing segment. The marketing operations of the Canadian Manufacturing segment have similar products and services, customer types, distribution methods and operate in the same regulatory environment as the commercial fuels business. The commercial fuels business includes cardlock, bulk plant and travel centre locations across Canada.

Financial Results

($ millions)	2022	2021 (1)	2020
Revenues	**7,792**	6,215	82
Purchased Product	**6,389**	5,156	—
Gross Margin (2)	**1,403**	1,059	82
Expenses			
Operating	**704**	486	37
Operating Margin	**699**	573	45
Depreciation, Depletion and Amortization	**208**	226	8
Segment Income (Loss)	**491**	347	37

(1) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details.

(2) Non-GAAP financial measure. See the Advisory.

Select Operating Results

	2022	2021	2020
Heavy Crude Oil Throughput Capacity (Mbbls/d)	**110.5**	110.5	—
Lloydminster Upgrader	**81.5**	81.5	—
Lloydminster Refinery	**29.0**	29.0	—
Heavy Crude Oil Throughput (Mbbls/d)	**92.9**	106.5	—
Lloydminster Upgrader	**68.7**	79.0	—
Lloydminster Refinery	**24.2**	27.5	—
Crude Utilization (1) (percent)	**84**	96	—
Refined Products Output (Mbbls/d)	**93.4**	107.9	—
Upgrading Differential (2)	**32.84**	16.83	—
Refining Margin (3)(4) ($/bbl)	**33.92**	18.09	—
Lloydminster Upgrader (4)	**36.04**	18.96	—
Lloydminster Refinery (4)	**27.91**	15.60	—
Unit Operating Expense (5) ($/bbl)	**13.91**	7.55	—
Ethanol Production (millions of litres/d)	**0.8**	0.7	—
Rail			
Volumes Loaded (6) (Mbbls/d)	**1.8**	12.1	30.4
Fuel Sales (7)			
Fuel Sales (millions of litres/d)	**6.2**	6.9	—
Fuel Sales per Outlet (thousands of litres/d)	**15.0**	13.0	—

(1) Based on crude oil 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 Advisory. Revenues from the Upgrader for the year ended December 31, 2022, were $3.8 billion (2021 – $3.2 billion). Revenues from the Lloydminster Refinery for the year ended December 31, 2022, were $1.1 billion (2021 – $816 million).
(4) Comparative information has been re-presented to include marketing activities.
(5) Specified financial measure. See the Advisory. Comparative information has been re-presented to include only operating expenses and throughput at the Upgrader and Lloydminster Refinery.
(6) Volumes transported outside of Alberta, Canada.
(7) On September 13, 2022, we closed the sales of 337 gas stations within our retail fuels network. We retained our commercial fuels business, which includes approximately 170 cardlock, bulk plant and travel centre locations. Total fuel sales volumes include the historical retail business and the remaining commercial fuels business. For the period of September 14, 2022 to December 31, 2022, the commercial fuels business averaged 0.7 million litres per day of gasoline sales volumes and 4.6 million litres per day of diesel fuel sales volumes, for a total of 5.3 million litres per day of sales volumes.

In 2022, crude oil throughput decreased 13.6 thousand barrels per day compared with 2021 due to planned turnarounds at the Lloydminster Upgrader and Lloydminster Refinery completed in the second quarter. Cold weather impacts and operational outages reduced throughput at the Upgrader in the fourth quarter of 2022. The Upgrader returned to full rates in the middle of January 2023. In addition, there were temporary unplanned outages at the Upgrader in the first and third quarters of 2022.

Revenues and Gross Margin

The Lloydminster Upgrader processes blended heavy crude oil and bitumen into high value synthetic crude oil and low sulphur distillates. 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. Revenues are dependent on market prices for asphalt and other industrial products. The 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 Lloydminster 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 2022, revenues increased by $1.6 billion to $7.8 billion, mainly due to higher synthetic crude oil benchmark prices and higher asphalt and industrial products prices. In addition, revenues from our commercial fuels business and historical retail network increased due to significantly higher benchmark gasoline and diesel prices. The increase in total revenues year-over-year was partially offset by lower sales volumes.

Gross margin increased $344 million in 2022 compared with 2021, due to a higher upgrading differential and higher margins on asphalt and industrial products. The year-over-year increase was offset by lower sales volumes, the 2021 settlement of a take-or-pay contract of $55 million and reduced activity at the Bruderheim crude-by-rail terminal.

See the Advisory for revenue and gross margin by asset.

Operating Expenses

Primary drivers of operating expenses in 2022 were repairs and maintenance, workforce and energy costs. Total operating costs increased in 2022 compared with 2021, primarily due to planned turnarounds and operational outages, combined with higher energy costs, maintenance, workforce and chemical costs.

Per-unit operating expenses increased primarily due to the same factors discussed above, combined with lower crude oil throughput volumes. Per-unit operating costs apply only to operating costs and throughput at the Upgrader and Lloydminster Refinery.

DD&A

In 2022, Canadian Manufacturing DD&A was $208 million, compared with $226 million in 2021.

U.S. Manufacturing

In 2022, we:

- Delivered safe operations at our operated assets.
- Generated Operating Margin of $1.7 billion, an increase of $1.5 billion compared with 2021, largely due to significantly higher market crack spreads.
- Achieved crude utilization of 90 percent at the Lima Refinery.
- Completed a significant planned turnaround at the non-operated Toledo Refinery, from April and through to early August. On September 20, 2022, there was an incident at the Toledo Refinery. The refinery remains shut down in a safe state.
- Completed planned turnarounds at the non-operated Wood River and Borger refineries in the first and second quarters, and an additional planned turnaround at the Wood River Refinery in September and October.
- Commenced commissioning activities for the Superior Refinery restart in December 2022 and will progress into the first quarter of 2023. The refinery remains on schedule to ramp up to full operations in the second quarter of 2023.
- Averaged crude utilization of 80 percent and crude oil throughput of 400.8 thousand barrels per day across all U.S. Manufacturing assets.
- Invested capital of $1.1 billion focused primarily on the Superior Refinery rebuild, and refining reliability initiatives at the Wood River, Borger and Toledo refineries, and yield optimization projects at the Wood River Refinery.

On August 8, 2022, we announced an agreement with BP to acquire their 50 percent interest in the Toledo Refinery in Ohio. The Toledo Acquisition will provide us full ownership and operatorship and further integrate our heavy oil production and refining capabilities. The transaction is expected to give 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, with opportunities to further optimize our heavy oil value chain through integration with our upstream assets. The transaction is expected to close at the end of February 2023.

Financial Results

($ millions)	**2022**	2021	2020
Revenues	**30,310**	20,043	4,733
Purchased Product	**26,112**	17,955	4,429
Gross Margin [(1)]	**4,198**	2,088	304
Expenses			
Operating	**2,346**	1,772	748
Realized (Gain) Loss on Risk Management	**112**	104	(21)
Operating Margin	**1,740**	212	(423)
Unrealized (Gain) Loss on Risk Management	**18**	1	(1)
Depreciation, Depletion and Amortization	**640**	2,381	728
Segment Income (Loss)	**1,082**	(2,170)	(1,150)

(1) Non-GAAP financial measure. See the Advisory.

Select Operating Results

	2022	2021	2020
Crude Oil Throughput Capacity (Mbbls/d)	**552.5**	502.5	247.5
Lima Refinery	**175.0**	175.0	—
Superior Refinery (1)	**50.0**	—	—
Toledo Refinery (2)	**80.0**	80.0	—
Wood River and Borger Refineries (2)	**247.5**	247.5	247.5
Crude Oil Throughput (Mbbls/d)	**400.8**	401.5	185.9
Lima Refinery	**157.9**	126.9	—
Superior Refinery (1)	**—**	—	—
Toledo Refinery (2)	**36.3**	69.9	—
Wood River and Borger Refineries (2)	**206.6**	204.7	185.9
Throughput by Product (Mbbls/d)			
Heavy Crude Oil	**116.1**	138.7	74.6
Light and Medium Crude Oil	**284.7**	262.8	111.3
Crude Utilization (percent)	**80**	80	75
Refining Margin (3)(4) ($/bbl)	**28.70**	14.25	4.47
Unit Operating Expense (4)(5) ($/bbl)	**16.04**	12.09	11.00

(1) The Superior Refinery commenced commissioning in December 2022. The permitted capacity is 50.0 Mbbls/d and is not included in the crude utilization calculation.
(2) Represents Cenovus's 50 percent interest in the non-operated Wood River, Borger and Toledo refinery operations.
(3) Contains a non-GAAP financial measure. See the Advisory.
(4) Based on crude oil throughput volumes and operating results at Wood River, Borger, Lima, Toledo and Superior refineries.
(5) Specified financial measure. See the Advisory.

In 2022, total crude utilization across the segment was 80 percent (2021 – 80 percent):

- The Lima Refinery had unplanned operational issues in the first quarter of the year following the turnaround completed in late 2021. The refinery performed well in the remainder of the year, until the winter storm Elliott events in December. Lima returned to normal rates in early January 2023. Crude utilization in 2022 was 90 percent (2021 – 73 percent).
- At the Toledo Refinery, we completed a significant planned turnaround starting in April and ramped up to full rates by mid-August 2022. On September 20, 2022, there was an incident at the Toledo Refinery. The refinery remains shut down in a safe state. Crude utilization in 2022 was 45 percent (2021 – 87 percent).
- We completed two planned turnarounds at the Wood River Refinery in 2022. The spring turnaround was delayed due to cold weather, resulting in labour shortages and cost overruns. The second turnaround was completed in September and October. 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 2023, and the refinery is currently operating at a substantial proportion of normal throughput. The refinery is expected to return to normal rates in the second quarter of 2023.
- We completed a turnaround at the Borger Refinery in the first and second quarters of 2022. In addition, the refinery had unplanned operational outages in the fourth quarter of 2022. The refinery returned to full rates by January 2023.
- Combined crude utilization for the Wood River and Borger refineries was 83 percent (2021 – 83 percent).

Early in the year, we operated at reduced rates at the Toledo, Lima and Wood River refineries due to low market crack spreads. In December, throughput at all the U.S. Manufacturing sites was significantly impacted by extreme cold weather. Wood River and Borger were also impacted by outages on a third party pipeline that brings feedstock to the refineries. Cold weather also impacted Toledo delaying the start up of certain operational areas that could be restarted.

The Superior Refinery commenced commissioning in December and will progress into the first quarter of 2023. The refinery is expected to ramp up to full operations in the second quarter of 2023.

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, distillate and secondary product output, the time lag between the purchase of crude oil feedstock and the processing of that crude oil through the refineries, and the cost of feedstock. Processing less expensive crude relative to WTI creates a feedstock cost advantage. Our feedstock costs are valued on a FIFO accounting basis.

Revenues increased $10.3 billion to $30.3 billion in 2022 compared with 2021. The increase was primarily due to significantly higher refined product pricing.

Gross margin increased $2.1 billion to $4.2 billion in 2022 compared with 2021, largely due to significantly improved market crack spreads. In 2022, RINs costs were $1.1 billion (2021 – $880 million). RINs prices averaged US$7.72 per barrel in 2022, compared with US$6.76 in 2021.

In 2022, we incurred realized risk management losses of $112 million (2021 – $104 million), which included a $36 million loss on the early liquidation of WTI positions in the second quarter. In 2022, we recorded unrealized losses of $18 million (2021 – $1 million) on our crude oil and refined products financial instruments.

Operating Expenses

Primary drivers of operating expenses in 2022 were repairs and maintenance, workforce, and energy costs.

Operating expenses increased $574 million in 2022, compared with 2021. The increase was mainly due to costs related to:

- Planned turnarounds at the Toledo, Wood River and Borger refineries.
- Increased maintenance and preparation work at the Superior Refinery as we prepare for restart.
- Higher energy and utility pricing.
- Higher workforce and chemical costs.

In 2022, per-unit operating expenses increased $3.95 per barrel of crude oil throughput in 2022, compared with 2021. The increase was primarily due to the same factors as discussed above. Superior Refinery operating expenses are included in per-unit operating expenses.

DD&A

U.S. Manufacturing DD&A was $640 million in 2022, compared with $2.4 billion in 2021. DD&A decreased compared with 2021 due to impairment charges of $1.9 billion recorded in the fourth quarter of 2021 related to the Lima, Wood River and Borger cash generating units ("CGUs"). In the fourth quarter of 2022, we recorded net impairment charges of $266 million. Refer to Note 11 of the Consolidated Financial Statements for further details.

CORPORATE AND ELIMINATIONS

In 2022, our corporate risk management activities resulted in:

- Unrealized risk management gains of $89 million (2021 – $18 million). Unrealized risk management gains in 2022 relate to renewable power contracts and foreign exchange risk management contracts.
- Realized risk management losses of $31 million related to foreign exchange risk management contracts. Losses of $101 million in 2021 were mainly due to the realization of WTI put and call option contracts acquired as part of the Arrangement.

Expenses

($ millions)	**2022**	2021	2020
General and Administrative	**865**	849	292
Finance Costs	**820**	1,082	536
Interest Income	**(81)**	(23)	(9)
Integration and Transaction Costs	**106**	349	29
Foreign Exchange (Gain) Loss, Net	**343**	(174)	(181)
Revaluation (Gains)	**(549)**	—	—
Re-measurement of Contingent Payments	**162**	575	(80)
(Gain) Loss on Divestiture of Assets	**(269)**	(229)	(81)
Other (Income) Loss, Net	**(532)**	(309)	40
	865	2,120	546

General and Administrative

Primary drivers of our general and administrative expenses were employee long-term incentive costs, workforce costs and information technology costs. General and administrative expenses, excluding stock-based compensation expense, declined $198 million year-over-year, primarily due to the provision for incentive rewards related to reaching our synergy targets in 2021. Stock-based compensation expense increased significantly by $214 million due to changes in our share price in 2022. Our closing common share price on December 31, 2022, was $26.27, an increase from $15.51 on December 31, 2021.

Finance Costs

Finance costs decreased by $262 million in 2022 compared with 2021 primarily as a result of debt purchases that lowered the Company's average long-term debt in 2022 compared with 2021. In addition, we recorded a net discount on the redemption of long-term debt of $29 million in 2022. Comparatively, we recorded a $121 million net premium on the redemption of long-term debt in 2021. 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 December 31, 2022, was 4.7 percent (2021 – 4.6 percent).

Integration and Transaction Costs

We incurred $90 million of integration costs as a result of the Arrangement, not including capital expenditures, in 2022, compared with $349 million in 2021. The integration of Cenovus and Husky is substantially complete.

In 2022, we incurred $95 million of Total Arrangement Integration Costs(1), which include capital expenditures (2021 – $402 million).

Transaction costs of $16 million were recognized in net earnings (loss) for the year ended December 31, 2022 associated with the Sunrise Acquisition and the pending Toledo Acquisition.

Foreign Exchange

($ millions)	**2022**	2021	2020
Unrealized Foreign Exchange (Gain) Loss	**365**	(312)	(131)
Realized Foreign Exchange (Gain) Loss	**(22)**	138	(50)
	343	(174)	(181)

In 2022, unrealized foreign exchange losses of $365 million were mainly as a result of the translation of our U.S. dollar denominated debt. Realized foreign exchange gains of $22 million were recorded in 2022, related to net gains on working capital, offset by losses on the purchase of long-term debt.

Revaluation Gains

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

(1) Non-GAAP financial measure. See the Advisory.

Re-measurement of Contingent Payments

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 2022, we paid $631 million under this agreement, which was recognized as cash flow from operating activities and reduced Adjusted Funds Flow.

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 quarterly payment is calculated as $2.8 million plus the difference between the average WCS price less $53.00 multiplied by $2.8 million, for any of the eight quarters the average WCS price is equal to or greater than $52.00 per barrel. If the average WCS price is less than $52.00 per barrel, no payment will be made for that quarter. The maximum cumulative variable payment is $600 million. For accounting purposes, the variable payment will be re-measured at fair value at each reporting date until the earlier of the cumulative maximum $600 million is reached or the eight quarters have lapsed, with changes in fair value recognized in net earnings (loss). The variable payment was recorded at a fair value of $600 million on the date of acquisition using an option pricing model.

As at December 31, 2022, the fair value of the variable payment was estimated to be $419 million resulting in a non-cash re-measurement gain of $89 million. The first quarterly period ended on November 30, 2022. As at December 31, 2022, $92 million is payable under this agreement.

As of December 31, 2022, average WCS forward pricing for the remaining term of the variable payment is approximately $72.79 per barrel.

(Gain) Loss on Divestiture of Assets

In 2022, we recognized a gain on divestiture of assets of $269 million (2021 – $229 million), due to the closing of the sales of our Tucker and Wembley assets in the first quarter, the divestiture of 12.5 percent of our interest in the White Rose field and satellite extensions in the second quarter, and the divestiture of 337 gas stations within our retail fuels network in the third quarter.

Other (Income) Loss, Net

In 2022, other income increased by $223 million compared with 2021, primarily due to insurance proceeds related to 2018 incidents at the Superior Refinery and in the Atlantic region and funding received under the Government of Alberta's Site Rehabilitation Program which provides qualifying entities funding to abandon and reclaim oil and gas sites. The increase was partially offset by the settlement of a legal claim in favour of Cenovus in the third quarter of 2021.

DD&A

DD&A for year ended December 31, 2022, was $113 million (2021 – $118 million).

Income Tax

($ millions)	**2022**	2021	2020
Current Tax			
Canada	**1,252**	104	(14)
United States	**104**	—	1
Asia Pacific	**262**	171	—
Other International	**21**	1	—
Current Tax Expense (Recovery)	**1,639**	276	(13)
Deferred Tax Expense (Recovery)	**642**	452	(838)
Total Tax Expense (Recovery)	**2,281**	728	(851)

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.

For the year ended December 31, 2022, the Company recorded a current tax expense related to operations in all jurisdictions that Cenovus operates. The increase is due to higher earnings compared to 2021 and the tax deductions available to calculate taxable income and losses available to offset that taxable income.

QUARTERLY RESULTS

($ millions, except where indicated)	2022 Q4	2022 Q3	2022 Q2	2022 Q1	2021 Q4	2021 Q3	2021 Q2	2021 Q1
Average Commodity Prices (US$/bbl)								
Dated Brent	**88.71**	100.85	113.78	101.41	79.73	73.47	68.83	60.90
WTI	**82.65**	91.55	108.41	94.29	77.19	70.56	66.07	57.84
WCS at Hardisty	**56.99**	71.69	95.61	79.76	62.55	56.98	54.58	45.37
Chicago 3-2-1 Crack Spread	**32.87**	38.87	46.50	18.35	16.06	20.67	20.50	12.93
RINs	**8.54**	8.11	7.80	6.44	6.11	7.32	8.12	5.49
Upstream Production Volumes								
Bitumen (Mbbls/d)	**593.5**	568.2	540.3	578.8	606.0	576.5	528.6	532.9
Heavy Crude Oil (Mbbls/d)	**15.8**	16.8	16.4	16.2	18.9	20.5	20.8	20.5
Light Crude Oil (Mbbls/d)	**17.1**	16.0	20.8	21.9	17.8	22.6	24.4	25.6
NGLs (Mbbls/d)	**38.5**	32.1	36.7	37.6	35.6	35.5	41.1	41.1
Conventional Natural Gas (MMcf/d)	**852.0**	868.7	882.2	865.3	883.5	897.9	905.6	894.9
Total Production Volumes (MBOE/d)	**806.9**	777.9	761.5	798.6	825.3	804.8	765.9	769.3
Downstream Crude Oil Throughput [(1)] (Mbbls/d)	**473.5**	533.5	457.3	501.8	469.9	554.1	539.0	469.1
Revenues [(2)]	**14,063**	17,471	19,165	16,198	13,726	12,701	10,637	9,293
Operating Margin [(3)]	**2,782**	3,339	4,678	3,464	2,600	2,710	2,184	1,879
Cash From (Used in) Operating Activities	**2,970**	4,089	2,979	1,365	2,184	2,138	1,369	228
Adjusted Funds Flow [(3)]	**2,346**	2,951	3,098	2,583	1,948	2,342	1,817	1,141
Per Share - Basic [(3)] ($)	**1.22**	1.53	1.57	1.30	0.97	1.16	0.90	0.57
Per Share - Diluted [(3)] ($)	**1.19**	1.49	1.53	1.27	0.97	1.15	0.89	0.56
Capital Investment	**1,274**	866	822	746	835	647	534	547
Free Funds Flow [(3)]	**1,072**	2,085	2,276	1,837	1,113	1,695	1,283	594
Excess Free Funds Flow [(3)(4)]	**786**	1,756	2,020	2,615	1,169	1,626	1,244	462
Net Earnings (Loss) [(5)]	**784**	1,609	2,432	1,625	(408)	551	224	220
Per Share - Basic ($)	**0.40**	0.83	1.23	0.81	(0.21)	0.27	0.11	0.10
Per Share - Diluted ($)	**0.39**	0.81	1.19	0.79	(0.21)	0.27	0.11	0.10
Total Assets	**55,869**	55,086	55,894	55,655	54,104	54,594	53,384	53,378
Total Long-Term Liabilities	**20,259**	19,378	20,742	21,889	23,191	22,929	22,972	24,266
Long-Term Debt, Including Current Portion	**8,691**	8,774	11,228	11,744	12,385	12,986	13,380	13,947
Net Debt	**4,282**	5,280	7,535	8,407	9,591	11,024	12,390	13,340
Cash Returns to Shareholders								
Common Shares – Base Dividends	**201**	205	207	69	70	35	36	35
Base Dividends Per Common Share ($)	**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	**387**	659	1,018	466	265	—	—	—
Preferred Share Dividends [(6)]	**—**	9	8	9	8	9	8	9

(1) Represents Cenovus's net interest in refining operations.
(2) Prior period results have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.
(3) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Advisory.
(4) New metric as of June 30, 2022, used to determine returns to shareholders.
(5) Net earnings (loss) for all periods in the table above is the same as net earnings (loss) from continuing operations.
(6) Preferred share dividends declared on November 1, 2022, were paid on January 3, 2023.

Fourth Quarter 2022 Results Compared with the Fourth Quarter 2021

The summary below compares financial and operating results for the three months ended December 31, 2022 compared with the same period in 2021.

Upstream Production Volumes

Total upstream production decreased 18.4 thousand BOE per day in the fourth quarter of 2022 compared with the same period in 2021.

Oil Sands crude oil production decreased 15.6 thousand barrels per day to 609.3 thousand barrels per day in 2022 compared with 2021. The decrease was primarily due to the sale of the Tucker asset on January 31, 2022. Crude oil production at the time of sale was approximately 20 thousand barrels per day. In addition, production decreased at Foster Creek as production reached peak levels in the fourth quarter of 2021 due to the timing of well pads starting up. Offsetting the decrease was the Sunrise Acquisition on August 31, 2022, and production of approximately 12.0 thousand barrels per day from the Spruce Lake North thermal plant in the fourth quarter of 2022. In the fourth quarter of 2022, we sold approximately 25 percent (2021 – 20 percent) of our Oil Sands crude oil volumes at U.S. destinations, improving our realized sales prices.

Conventional production was 125.5 thousand BOE per day in 2022, essentially unchanged from 125.3 thousand BOE per day in 2021. Production decreases from asset sales in the first quarter of 2022 were offset by 36 net new wells brought on production in the year-ended 2022, combined with production from well reactivations and workover activity.

Offshore production was 70.2 thousand BOE per day in 2022, compared with 73.1 thousand BOE per day in 2021. The decrease was primarily due to the working interest restructuring on the White Rose fields in the second quarter of 2022, combined with contract amendments in China. These were partially offset by first gas production at the MBH and MDA fields in Indonesia in the fourth quarter of 2022.

Downstream Manufacturing Throughput

Total crude oil throughput was consistent in the fourth quarter of 2022 compared with the same period in 2021.

Canadian Manufacturing throughput decreased 14.0 thousand barrels per day to 94.3 thousand barrels per day in 2022. Cold weather impacts and unplanned operational outages reduced throughput at the Upgrader in the fourth quarter of 2022. The Upgrader returned to full rates in the middle of January 2023. The Lloydminster Refinery had minor unplanned outages in the fourth quarter of 2022, but ran well in December and into 2023.

U.S. Manufacturing throughput increased 17.6 thousand barrels per day to 379.2 thousand compared with 2021, primarily due to the completion of a planned turnaround in the fourth quarter of 2021 at the Lima Refinery. The increase was partially offset by unplanned operational issues, weather-related impacts and third-party outages impacting the Lima, Wood River and Borger refineries in December, in addition to the shutdown of the Toledo Refinery, and Wood River running at reduced rates in December due to an operational incident.

Revenues

Revenues increased $337 million to $14.1 billion in 2022 compared with 2021. Downstream revenues increased $370 million primarily due to higher refined product pricing. Upstream revenues were flat compared with 2021, as higher realized prices in the Conventional segment were offset by lower sales volumes in the Atlantic region. Oil Sands revenues were consistent with 2021, due to flat sales volumes and realized prices year-over year.

Operating Margin

Operating Margin increased in the fourth quarter of 2022, primarily due to increased refining margins from our downstream business resulting from higher market crack spreads. The increase was partially offset by:

- Increased blending costs due to higher condensate prices impacting our Oil Sands segment.
- Higher Renewable Identification Numbers (“RINs”) costs impacting our U.S. Manufacturing segment.
- Increased transportation costs from our upstream business, due to increased tariff rates and higher rail costs due to pipeline outages in the quarter.

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

Cash from operating activities and Adjusted Funds Flow were higher in 2022, primarily due to increased Operating Margin, as discussed above, and no quarterly contingent payments in 2022 (2021 – $119 million). The increase was partially offset by higher cash taxes in 2022.

Cash from operating activities also increased as the change in non-cash working capital was $402 million greater than 2021. The increase was due to lower accounts receivable and higher income tax payable, partially offset by lower accounts payable on December 31, 2022, compared with September 30, 2022.

Net Earnings (Loss)

Net earnings in the fourth quarter of 2022 was $784 million compared with a net loss of $408 million 2021 due to:

- Net impairment charges in the fourth quarter of 2022 of $266 million, compared with net impairment charges of $1.6 billion in the fourth quarter of 2021.
- Higher operating margin, as discussed above.

The increase was partially offset by:

- Unrealized risk management losses of $37 million in 2022 (2021 – $222 million gain).
- Higher gain on divestiture of assets in 2021.

Capital Investment

Capital investment in the fourth quarter of 2022 was $1.3 billion, compared with $835 million in 2021. The increase is primarily due to higher capital spending in our upstream operations, including higher investment in Sunrise following the closing of the Sunrise Acquisition, incremental capital at Foster Creek, Christina Lake and Lloydminster thermal assets, increased drilling in the Conventional segment and work on the West White Rose project.

Excess Free Funds Flow

Excess Free Funds Flow was $786 million in the fourth quarter of 2022 (2021 – $1.2 billion). The decrease was due to higher capital spending and base dividends paid in 2022, partially offset by higher adjusted funds flow in 2022.

OIL AND GAS RESERVES

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

As at December 31, 2021 (before royalties)	Bitumen [(1)] (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas [(2)] (Bcf)	Total (MMBOE)
Total Proved	5,573	45	89	2,219	**6,077**
Probable	1,850	152	39	959	**2,201**
Total Proved Plus Probable	7,423	197	128	3,178	**8,278**

(1) Includes heavy crude oil that is not material.
(2) Includes shale gas that is not material.

Developments in 2022 compared with 2021 include:

- Bitumen gross total proved and gross total proved plus probable reserves increased by 19 million barrels and 617 million barrels, respectively. The increases were due to additions from the regulatory approval at Foster Creek, the Sunrise Acquisition and improved recovery performance at Sunrise and Lloydminster thermal, partially offset by the Tucker asset sale and current year production.
- Light and medium oil gross total proved and gross total proved plus probable reserves decreased by three million barrels and 26 million barrels, respectively. The decreases were due to the disposition of 12.5 percent of the Company's working interest in the White Rose field and satellite extensions, the Wembley asset sale and current year production, partially offset by additions from updates to the Atlantic region and Conventional segment development plans.
- NGLs gross total proved and gross total proved plus probable reserves decreased by seven million barrels each, due to dispositions in the Conventional segment and current year production, partially offset by additions from updates to the development plan and economic factors related to increased product pricing for the Conventional segment.
- Conventional natural gas gross total proved reserves decreased by 25 billion cubic feet due to the Wembley asset sale and current year production, partially offset by updates to the development plans, improved recovery performance, and economic factors due to improved product pricing for the Conventional segment. Conventional natural gas gross total proved plus probable reserves increased by 45 billion cubic feet due to updates to the development plan and economic factors due to improved product pricing for the Conventional segment, partially offset by the Wembley asset sale and current year production.

The reserves data is presented as at December 31, 2022 using an average of forecasts ("Average Forecast") by McDaniel & Associates Consultants Ltd., GLJ Ltd. and Sproule Associates Limited. The Average Forecast prices and costs are dated January 1, 2023. Comparative information as at December 31, 2021 uses the January 1, 2022 Average Forecast prices and costs.

Additional information with respect to the evaluation and reporting of our reserves in accordance with National Instrument 51-101, "*Standards of Disclosure for Oil and Gas Activities*" is contained in our AIF for the year ended December 31, 2022. Our AIF is available on SEDAR at sedar.com, on EDGAR at sec.gov and on our website at cenovus.com. Material risks and uncertainties associated with estimates of reserves are discussed in this MD&A in the Risk Management and Risk Factors section and the Advisory section.

LIQUIDITY AND CAPITAL RESOURCES

During 2022, we further defined our capital allocation framework to ensure we continue to strengthen our balance sheet, enable flexibility in both high and low commodity price environments, and improve our shareholder value proposition. The Company's capital allocation framework enables a shift to paying out a higher percentage of Excess Free Funds Flow to shareholders with lower leverage and a lower risk profile. Our long-term Net Debt to Adjusted Funds Flow Target is approximately 1.0 times at the bottom of the commodity price cycle.

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.

($ millions)	**2022**	2021	2020
Cash From (Used In)			
Operating Activities	**11,403**	5,919	273
Investing Activities	**(2,314)**	(942)	(863)
Net Cash Provided (Used) Before Financing Activities	**9,089**	4,977	(590)
Financing Activities	**(7,676)**	(2,507)	837
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**238**	25	(55)
Increase (Decrease) in Cash and Cash Equivalents	**1,651**	2,495	192

As at ($ millions)	**2022**	2021	2020
Cash and Cash Equivalents	**4,524**	2,873	378
Total Debt	**8,806**	12,464	7,562

Cash From (Used in) Operating Activities

For the year ended December 31, 2022, cash generated from operating activities increased compared with 2021 due to higher Operating Margin, changes in non-cash working capital, lower finance costs and lower integration and transaction costs.

Excluding the contingent payment, our adjusted working capital was $4.7 billion at December 31, 2022. At December 31, 2021, adjusted working capital excluding the contingent payment and assets held for sale and liabilities related to assets held for sale was $3.8 billion. The increase was primarily due to the improved commodity price environment as discussed in the Operating and Financial Results section of this MD&A. Working capital increased due to higher cash and inventories, partially offset by higher income tax payable and lower accounts receivable.

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

Cash From (Used in) Investing Activities

Cash used in investing activities was higher in 2022 compared with 2021 largely due to higher capital spending, cash paid on the Sunrise Acquisition in 2022 and cash acquired in the Arrangement in 2021. The increase was partially offset by higher proceeds from divestitures in 2022.

Cash From (Used in) Financing Activities

As part of our overall deleveraging in 2022, we:

- Paid US$402 million to purchase the full amount of our 3.80 percent unsecured notes due in 2023 and 4.00 percent unsecured notes due in 2024, with principal amounts of US$115 million and US$269 million, respectively. We paid a premium on redemption of US$18 million.
- Paid $750 million to purchase the full principal amount outstanding of our 3.55 percent unsecured notes due in 2025 at par.
- Paid US$2.2 billion to purchase unsecured notes due between 2025 and 2043, at a premium of US$23 million.

During 2022, net short-term borrowings increased by $34 million, related to draws on the WRB Refining LP uncommitted demand facilities.

In 2022, the Company purchased 112 million common shares through our NCIBs, at a volume weighted average price of $22.49 per common share for a total of $2.5 billion (December 31, 2021 – $265 million). The common shares were subsequently cancelled. During 2022, we paid base dividends of $682 million and variable dividends of $219 million on our common shares.

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 December 31,		Year Ended December 31,		
($ millions)	**2022**	2021	**2022**	2021	2020
Cash From (Used in) Operating Activities	**2,970**	2,184	**11,403**	5,919	273
(Add) Deduct:					
Settlement of Decommissioning Liabilities	**(49)**	(35)	**(150)**	(102)	(42)
Net Change in Non-Cash Working Capital	**673**	271	**575**	(1,227)	198
Adjusted Funds Flow	**2,346**	1,948	**10,978**	7,248	117
Capital Investment	**1,274**	835	**3,708**	2,563	841
Free Funds Flow	**1,072**	1,113	**7,270**	4,685	(724)
Add (Deduct):					
Base Dividends Paid on Common Shares	**(201)**	(70)			
Dividends Paid on Preferred Shares	**—**	(8)			
Settlement of Decommissioning Liabilities	**(49)**	(35)			
Principal Repayment of Leases	**(74)**	(78)			
Acquisitions, Net of Cash Acquired	**(7)**	—			
Proceeds From Divestitures	**45**	247			
Excess Free Funds Flow	**786**	1,169			

Returns to Shareholders Target

	Three Months Ended		
($ millions)	**December 31, 2022**	September 30, 2022	June 30, 2022
Excess Free Funds Flow	**786**	1,756	2,020
Target Return [1]	**393**	878	1,010
Less: Purchase of Common Shares Under NCIBs	**(387)**	(659)	(1,018)
Amount Available for Variable Dividend	**6**	219	(8)

(1) Based on our capital allocation framework, as a result of Net Debt as at September 30, 2022, June 30, 2022 and March 31, 2022, being less than $9 billion and greater than $4 billion, Target Return was determined to be 50 percent of Excess Free Funds Flow.

In the fourth quarter of 2022, we paid variable dividends of $219 million. Returns to shareholders through share buybacks were within $50 million of the fourth quarter Target Return, as such no variable dividend was declared for the quarter.

Short-Term Borrowings

As at December 31, 2022, US$170 million was drawn on the WRB uncommitted demand facility, of which the Company's proportionate share was US$85 million (C$115 million) (December 31, 2021 – US$125 million of which the Company's proportionate share was US$63 million (C$79 million)).

Long-Term Debt and Total Debt

Total Debt as at December 31, 2022, was $8.8 billion (December 31, 2021 – $12.5 billion), which includes $8.7 billion of long-term debt (December 31, 2021 – $12.4 billion). The decrease in Total Debt and long-term debt was due to the purchase of US$2.6 billion and $750 million of principal related to outstanding unsecured notes in 2022.

As at December 31, 2022, we were in compliance with all of the terms of our debt agreements.

Available Sources of Liquidity

The following sources of liquidity are available as at December 31, 2022:

($ millions)	Maturity	Amount Available
Cash and Cash Equivalents	**N/A**	**4,524**
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 [2]		
Cenovus Energy Inc. [3]	**N/A**	**1,002**
WRB Refining LP [4]	**N/A**	**190**

(1) No amounts were drawn on the committed credit facility as at December 31, 2022 (December 31, 2021 - $nil).
(2) On November 24, 2022, the Company cancelled the SOSP uncommitted demand credit facility.
(3) 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 December 31, 2022, there were outstanding letters of credit aggregating to $490 million (December 31, 2021 – $565 million) and no direct borrowings.
(4) Represents Cenovus's 50 percent share of US$450 million (our proportionate share – US$225 million) available to cover short-term working capital requirements. As at December 31, 2022, US$170 million was drawn on these facilities, of which the Company's proportionate share was US$85 million (C$115 million) (December 31, 2021 – US$125 million of which the Company's proportionate share was US $63 million (C$79 million)).

On November 10, 2022, Cenovus amended its existing committed credit facility to decrease the capacity by $500 million to $5.5 billion and to extend the maturity dates.

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

	Unsecured Notes	
	U.S. Dollar Denominated (US $ millions)	**Canadian Dollar Denominated** ($ millions)
As at December 31, 2021	**7,385**	**2,750**
Purchases	**(2,558)**	**(750)**
As at December 31, 2022	**4,827**	**2,000**

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 December 31, 2022, US$4.7 billion remained available under the base shelf prospectus for permitted offerings (December 31, 2021 – 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 26 of the Consolidated Financial Statements for further details.

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

As at	**2022**	2021	2020
Net Debt to Capitalization Ratio (percent)	**13**	29	30
Net Debt to Adjusted Funds Flow Ratio (times)	**0.4**	1.3	61.4
Net Debt to Adjusted EBITDA Ratio (times)	**0.3**	1.2	11.9

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

Our Net Debt to Capitalization Ratio as at December 31, 2022 decreased compared with December 31, 2021, primarily due to higher net earnings and ongoing reductions in Net Debt.

Our Net Debt to Adjusted Funds Flow Ratio and Net Debt to Adjusted EBITDA Ratio as at December 31, 2022 decreased compared with December 31, 2021, as a result of higher Operating Margin and lower Net Debt. 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

As at December 31, 2022, there were approximately 1,909 million common shares outstanding (December 31, 2021 – 2,001 million common shares) and 36 million preferred shares outstanding (December 31, 2021 – 36 million preferred shares). Refer to Note 32 of the Consolidated Financial Statements for further details.

In November 2021, we commenced a NCIB for the purchase of up to 146.5 million of the Company's common shares between November 9, 2021 and November 8, 2022. On November 7, 2022, we renewed the NCIB program to purchase up to an additional 136.7 million of the Company's common shares between November 9, 2022, and November 8, 2023. In 2022, Cenovus purchased and cancelled 112 million common shares for $2.5 billion (year ended December 31, 2021 – 17 million common shares for $265 million), at a volume weighted average price of $22.49 per common share through our NCIBs. Paid in surplus was reduced by $1.6 billion (December 31, 2021 – $120 million), representing the excess of the purchase price of the common shares over their average carrying value. From January 1, 2023, to February 13, 2023, the Company purchased an additional 1.4 million common shares for $36.8 million. As at February 13, 2023, 123.8 million common shares remain available for purchase under the 2023 NCIB.

As at December 31, 2022, there were approximately 56 million Cenovus Warrants outstanding (December 31, 2021 – 65 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 32 of the Consolidated Financial Statements for further details.

Refer to Note 34 of the Consolidated Financial Statements for further details on our stock option plans and our performance share unit, restricted share unit and deferred share unit plans.

Our outstanding share data is as follows:

As at February 13, 2023	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**1,907,867**	**N/A**
Cenovus Warrants	**55,691**	**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	**17,373**	**8,312**
Other Stock-Based Compensation Plans	**16,891**	**1,581**

Common Share Dividends

In 2022, we paid base dividends of $682 million or $0.350 per common share (2021 – $176 million or $0.088 per common share) and variable dividends of $219 million or $0.114 per common share (2021 – $nil).

The Board declared a first quarter base dividend of $0.105 per common share, payable on March 31, 2023, to common shareholders of record as at March 15, 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 2022, dividends of $26 million were paid on the series 1, 2, 3, 5 and 7 preferred shares (December 31, 2021 — $34 million). The decrease from 2021 is related to timing differences between the declaration date and payment date. The declaration of preferred share dividends is at the sole discretion of the Board and is considered quarterly. The Board declared a first quarter dividend on the series 1, 2, 3, 5 and 7 preferred shares of $9 million, payable on March 31, 2023, to preferred shareholders of record as of March 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 800 thousand BOE per day and 840 thousand BOE per day and our downstream crude oil throughput average between 610 thousand barrels per day to 660 thousand barrels per day in 2023. Our 2023 guidance dated December 5, 2022, is available on our website at cenovus.com.

Contractual Obligations and Commitments

We have obligations for goods and services entered into in the normal course of business. Commitments are largely related to transportation agreements. Commitments that have original maturities of less than one year are excluded from the table below. For further information, see Note 40 to the Consolidated Financial Statements.

Our total commitments were $33.0 billion as at December 31, 2022, of which $21.1 billion are for various transportation and storage commitments and $9.4 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.

Our commitments with HMLP at December 31, 2022, include $2.2 billion related to long-term transportation and storage commitments.

As at December 31, 2022 ($ millions)	2023	2024	2025	2026	2027	Thereafter	**Total**
Commitments (1)							
Transportation and Storage (2)	1,747	2,011	1,542	1,416	1,360	13,005	**21,081**
Product Purchases (3)	1,626	1,509	922	922	922	3,457	**9,358**
Real Estate (4)	48	50	50	50	54	604	**856**
Obligation to Fund Equity-Accounted Affiliate (5)	92	105	96	96	91	143	**623**
Other Long-Term Commitments	381	90	75	74	65	395	**1,080**
Total Commitments	3,894	3,765	2,685	2,558	2,492	17,604	**32,998**
Long-Term Debt (Principal and Interest)	401	401	582	392	1,622	11,196	**14,594**
Decommissioning Liabilities	263	254	249	248	247	5,979	**7,240**
Contingent Payments	271	167	—	—	—	—	**438**
Lease Liabilities (Principal and Interest) (6)	426	407	339	320	276	2,889	**4,657**
Total Commitments and Obligations	5,255	4,994	3,855	3,518	4,637	37,668	**59,927**

(1) Commitments are reflected at Cenovus's proportionate share of the underlying contract.
(2) Includes transportation commitments of $9.1 billion (December 31, 2021 – $8.1 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 commencement of the contract.
(3) Prior to September 30, 2022, product purchases were included in Transportation and Storage.
(4) Relates to the non-lease components of lease liabilities consisting of operating costs and unreserved parking for office space. Excludes committed payments for which a provision has been provided.
(5) Relates to funding obligations for HCML.
(6) Lease contracts related to office space, our retail and commercial network, railcars, storage assets, drilling rigs and other refining and field equipment.

As at December 31, 2022, outstanding letters of credit issued as security for performance under certain contracts totaled $490 million (December 31, 2021 – $565 million).

Legal Proceedings

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

Transactions with Related Parties

Transactions with HMLP are related party transactions as we have a 35 percent ownership 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 year ended December 31, 2022, we charged HMLP $188 million for construction and management services (2021 – $243 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 year ended December 31, 2022, we incurred costs of $263 million for the use of HMLP's pipeline systems, as well as transportation and storage services (2021 – $284 million).

RISK MANAGEMENT AND RISK FACTORS

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

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

Risk Governance

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

Risk Factors

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

Pandemic Risk

The COVID-19 pandemic remains a risk for the Company. While restrictions have ended or been relaxed in many parts of the world, other jurisdictions continue to impose measures to combat the virus. The COVID-19 pandemic (including the emergence of variant strains of COVID-19) and measures taken in response by governments and health authorities around the world have created ongoing uncertainty that has resulted in and may continue to result in restrictions on movement and businesses being maintained, re-imposed or imposed on a stricter basis, which could negatively impact our business, results of operations and financial condition.

The COVID-19 pandemic, or other pandemics, endemics or outbreaks, may increase our exposure to, and the magnitude of, each of the risks identified in this Risk Management and Risk Factors section of this MD&A and identified in other documents we file with securities regulators from time to time. The duration or extent of the impacts of the COVID-19 pandemic on our business, results of operations and financial condition will depend on future developments, which are highly uncertain and are difficult to predict with any degree of precision, and include but are not limited to: the severity, duration, spread or resurgence of COVID-19 or its variants; the timing, extent and effectiveness of actions taken to contain or treat COVID-19 or its variants, including the availability, distribution rate, effectiveness and public uptake of any vaccines or boosters; and the speed at which, and extent to which, normal economic and operating conditions resume.

There are no comparable recent events that provide guidance as to the effect the COVID-19 pandemic may have, and, as a result, the ultimate impact of the COVID-19 pandemic is highly uncertain and subject to change. The COVID-19 pandemic and the corresponding measures we take to protect the health and safety of our staff and the continuity of our business may result in new legal challenges and disputes, including, but not limited to, litigation involving contract parties or employees and class action claims.

Financial Risk

Commodity Prices

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

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

Our natural gas and NGL production is currently located in Western Canada and Asia Pacific. Natural gas and NGL prices are impacted by a number of factors, including, but not limited to: global and regional supply and demand for natural gas and NGLs; global economic conditions; market competitiveness; developments related to the market for liquefied natural gas; levels of natural gas and NGL inventories; export capacity; current and potential future environmental regulations, including regulations pertaining to the production and use of non-renewable resources; emissions, including, but not limited to carbon; market pricing and the accessibility and liquidity of these and related markets; prices and availability of alternate sources of energy; actions of domestic or foreign governments or regulatory bodies that may impact commodity prices; enforcement of government or environmental regulations; public sentiment towards the use of non-renewable resources, including natural gas and NGLs; political stability and social conditions in natural gas and NGL-producing countries; market access constraints and transportation interruptions; terrorist threats; technological developments; economic sanctions; outbreak or continuation of a pandemic or war; the occurrence of natural disasters; and weather conditions.

Refined product prices are impacted by a number of factors, including, but not limited to: global and regional supply and demand for refined products; the ability of producers and governments to replace reduced supply; global economic conditions and activity; inflation and rising interest rates; central bank policies; seasonal trends; the potential for a recession; market competitiveness; developments related to the market for refined products; levels of refined product inventories; refinery availability; planned and unplanned refinery maintenance; current and potential future environmental regulations, including the United States Renewable Fuel Standard ("RFS") and other regulations pertaining to the production and use of refined products and non-renewable resources; emissions, including, but not limited to carbon; market pricing and the accessibility and liquidity of these and related markets; prices and availability of alternate sources of energy; public sentiment towards the use of non-renewable resources, including refined products; market access constraints and transportation interruptions; terrorist threats; technological developments; economic sanctions; outbreak or continuation of a pandemic or war; the occurrence of natural disasters; and weather conditions.

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

In addition, relating to the level of future demand (and corresponding price levels) for each of crude oil, refined products, natural gas and NGLs, there has been a significant increase in focus on the timing for and pace of the transition to a lower-carbon economy. See "Climate Change Transition – Demand and Commodity Prices" below. All of these factors are beyond our control and can result in a high degree of both cost and price volatility. Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars. See "Foreign Exchange Rates" below.

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

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

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

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts, and market access commitments, and generally through our access to our committed credit facility. In certain instances, we will use derivative instruments to manage exposure to price volatility on a portion of our refined product, oil and gas production, inventory or volumes in long-distance transit. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 37 and 38 of the Consolidated Financial Statements.

Hedging Activities

Our Market Risk Management Policy, which has been approved by our Board, allows Management to use derivative instruments, including exchange-traded futures contracts, commodity put and call options and other approved instruments such as non-exchange-traded instruments, as needed to help mitigate the impact of changes in crude oil and condensate prices and differentials, natural gas spreads, basis and prices, NGLs, electricity prices, refined product and crack spread margins, as well as fluctuations in foreign exchange rates and interest rates. We may also use fixed-price commitments for the purchase or sale of crude oil, natural gas, NGLs and refined products. We may also use derivative instruments in various operational markets to help optimize our supply costs or sales of our production.

These hedging activities may expose us to risks which may cause significant loss. These risks include, but are not limited to: changes in the valuation of the hedge instrument being poorly correlated to the change in the valuation of the underlying exposures being hedged; change in price of the underlying commodity or market value of the instrument; lack of market liquidity; insufficient counterparties to transact with; counterparty default; deficiency in systems or controls; human error; and the unenforceability of contracts.

For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 3, 37 and 38 of the Consolidated Financial Statements.

Risks Associated with Derivative Financial Instruments

Derivative financial instruments expose us to the risk that a counterparty may default on its contractual obligations. This risk is partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in our Board-approved Credit Policy. Derivative financial instruments also expose us to the risk of a loss from adverse changes in the market value of financial instruments or if we are unable to fulfill our delivery obligations related to the underlying physical transaction. These risks are managed through hedging limits authorized according to our Market Risk Management Policy. Although we have suspended our crude oil sales price risk management activities related to WTI, certain financial instruments related to our condensate, feedstock and refined product price risk management programs which include WTI, remain outstanding and will continue to be used, in addition to financial instruments related to natural gas, electricity, interest and exchange rates applicable to our business. As such, we will be exposed to the risk of a loss from adverse changes in the market value of any such financial instruments. These financial instruments may also limit the benefit to us if commodity prices, interest or foreign exchange rates change. Fluctuations in the price of WTI may have a larger impact on our financial condition, results of operations, cash flows, growth, access to capital, ability to fund share repurchases and/or dividends and cost of borrowing, compared to the periods prior to the suspension of our crude oil sales price risk management activities related to WTI.

For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 3, 37 and 38 of the Consolidated Financial Statements.

Impact of Financial Risk Management Activities

Cenovus makes storage and transportation decisions, considering our marketing and transportation infrastructure including storage and pipeline assets, to optimize product mix, delivery points, 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 a rising commodity price environment, we expect to realize losses on our risk management activities but recognize gains on the underlying physical inventory sold in the period, and we expect the opposite to occur in a falling commodity price environment. In 2022, we incurred a realized loss on our risk management positions due to the settlement of benchmark prices relative to our risk management contract prices but recognized a gain on the underlying physical inventory sold during such period due to changing benchmark prices.

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

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

As at December 31, 2022	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10.00/bbl Applied to WTI, Condensate and Related Hedges	**1**	**(1)**
WCS and Condensate Differential Price[1]	± US$2.50/bbl Applied to Differential Hedges Tied to Production	**13**	**(13)**
WCS (Hardisty) Differential Price	± US$5.00/bbl Applied to WCS Differential Hedges Tied to Production	**(1)**	**1**
Refined Products Commodity Price	± US$10.00/bbl Applied to Heating Oil and Gasoline Hedges	**(2)**	**2**
Natural Gas Basis Price	± US$0.50/MCF Applied to Natural Gas Basis Hedges	**1**	**(1)**
Power Commodity Price	± C$20.00/Megawatt Hour Applied to Power Hedges	**113**	**(113)**
U.S. to Canadian Dollar Exchange Rate	± 0.05 in the U.S. to Canadian Dollar Exchange Rate	**14**	**(17)**

(1) Excludes WCS (Hardisty) differential.

For further information on our risk management positions, see Notes 37 and 38 of the Consolidated Financial Statements.

Exposure to Counterparties

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

Credit, Liquidity and Availability of Future Financing

The future development of our business may be dependent on our ability to obtain additional capital, including, but not limited to, debt and equity financing. Among other things, unpredictable financial markets, a sustained commodity price downturn or significant unanticipated expenses, or a change in law, market fundamentals, our credit ratings, business operations or investor or lender policy or sentiment, may impede our ability to secure and maintain cost-effective financing. Stakeholders are increasingly considering ESG matters, including climate-related targets, and failure to achieve our emissions reduction targets, or the perception that our targets are insufficient or will not be achieved, could adversely affect our ability to access cost-effective capital. An inability to access capital, on terms acceptable to us or at all, could affect our ability to make future capital expenditures, to maintain desirable financial ratios and to meet all of our financial obligations as they come due, potentially resulting in a material adverse effect on our business, financial condition, results of operations, cash flows, ability to comply with various financial and operating covenants, credit ratings and reputation.

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

Our liquidity risk is mitigated through actively managing cash and cash equivalents, cash flow provided by operating activities, available credit facility capacity, and accessing the capital markets.

We are required to comply with various financial and operating covenants under our credit facility and the indentures governing our debt securities. We routinely review our covenants to ensure compliance. In the event that we do not comply with such covenants, our access to capital could be restricted or repayment could be accelerated.

Credit Ratings

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

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

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

Foreign Exchange Rates

Fluctuations in foreign exchange rates between various currencies may affect our results, particularly the U.S./Canadian dollar and Chinese Yuan (“RMB”)/Canadian dollar exchange rates. Global prices for crude oil, refined products, and natural gas are generally set in U.S. dollars, while many of our operating and capital costs are in Canadian dollars. A change in the value of the Canadian dollar, as a result of changing benchmark lending rates, macroeconomic factors or otherwise, relative to the U.S. dollar will increase or decrease revenues, as expressed in Canadian dollars, received from the sale of oil and refined products, and from some of our natural gas sales. In addition, a change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in our U.S. dollar denominated debt and related U.S. dollar interest expense, as expressed in Canadian dollars. A portion of our long-term sales contracts in Asia Pacific are priced in RMB. A change in the value of the Canadian dollar relative to RMB will increase or decrease revenues, as expressed in Canadian dollars, received from the sale of natural gas and NGLs in the region. We may periodically enter into transactions to manage our exposure to exchange rate fluctuations. However, the fluctuations in exchange rates are beyond our control and could have a material adverse effect on our cash flows, results of operations and financial condition.

Interest Rates

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

Dividend Payments and Purchase of Securities

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

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

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

Operational Risk

Operational Considerations (Safety, Environment and Reliability)

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

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

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

To partially mitigate our risks, we have policies and an associated system of standards, processes and procedures to identify, assess and mitigate safety, operational and environmental risk across our operations. In addition, we attempt to partially mitigate operational risks by maintaining a comprehensive insurance program in respect of our assets and operations. However, not all potential occurrences and disruptions in respect of our assets or operations are insured or are insurable, and it cannot be guaranteed that our insurance coverage will be available or sufficient to fully cover any claims that may arise from such occurrences or disruptions. The occurrence of an event that is not fully covered by our insurance program could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Market Access Constraints and Transportation Restrictions

Our production is transported through various pipelines, terminals and marine, rail and truck networks, and our refineries are reliant on various pipelines and marine, rail and truck networks to transport feedstock and refined products to and from our facilities. Increased tariffs or disruptions in, or restricted availability of, pipeline service and/or marine, rail or truck transport, could adversely affect crude oil, refined products, natural gas and NGLs sales, projected production growth, upstream or refining operations and cash flows.

Interruptions or restrictions in the availability of these pipeline, terminals, marine, rail and truck systems may also limit the ability to deliver production volumes and could adversely impact commodity prices, sales volumes and/or the prices received for our products. These interruptions and restrictions may be caused by, among other things, the inability of the pipeline or marine, rail or truck networks to operate, or may be related to capacity constraints if supply into the system exceeds the infrastructure capacity. There can be no certainty that investments in new pipeline projects will be made by applicable third-party pipeline providers, that any applications to expand capacity will receive the required regulatory approvals, or that any such approvals will result in the construction of the pipeline project, or that such projects would provide sufficient transportation capacity.

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

Reserves Replacement and Reserve Estimates

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

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

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

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

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

Cost Management and Inflation

Development, operating and construction costs are affected by a number of factors including, but not limited to: development, adoption and success of new technologies; inflationary price pressure; changes in regulatory compliance costs; scheduling delays; interruptions to existing market access infrastructure; failure to maintain quality construction and manufacturing standards; equipment limitations, including the cost or availability of oil and gas field equipment; commodity prices; higher steam-oil ratios in our Oil Sands operations; additional government or environmental regulations and supply chain disruptions, including access to skilled labour and critical third-party services. In addition, if our development, operating, construction or labour costs were to become subject to significant inflationary pressures, we may not be able to fully offset such higher costs through corresponding increases in commodity prices. Further, there can be no assurance that any governmental action to mitigate inflationary cycles will be taken or will be effective. Central banks have increased interest rates in response to inflation and additional rate increases may be implemented. Governmental actions, such as the imposition of higher interest rates or wage controls may also negatively impact the Company's costs and magnify the impacts of other risks identified in the Risk Management and Risk Factors section of this MD&A, including those set out under the "Financial Risk - Interest Rates" section above.

Continued inflation, any governmental response thereto, our inability to manage costs, or our inability to secure equipment, materials, skilled labour or third-party services necessary to our business activities for the expected price, on the expected timeline, or at all, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Competition

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

Project Execution

We manage a variety of oil, natural gas and refining projects across our global portfolio of assets, including the current rebuild of our Superior Refinery and the restart of the West White Rose Project. The wide range of risks associated with project development and execution, as well as the commissioning and integration of new facilities with existing assets, can impact the economic viability of our projects. These risks include, but are not limited to: our ability to obtain the necessary environmental and regulatory approvals; our ability to obtain favourable terms or to be granted access within land-use agreements; risks relating to schedule, resources and costs, including the availability and cost of materials, equipment and qualified personnel; the impact of supply chain disruptions; the impact of general economic, business and market conditions including inflationary pressures; the impact of weather conditions; risk related to the accuracy of project cost estimates; our ability to finance capital expenditures and expenses; our ability to source or complete strategic transactions; the effect of the COVID-19 pandemic on project execution and timelines; and the effect of changing government regulation and public expectations in relation to the impacts of oil and gas operations on the environment. The commissioning and integration of new facilities within our existing asset base could cause delays in achieving performance targets and objectives. Failure to manage these risks could affect our safety and environmental record and have a material adverse effect on our financial condition, results of operations and cash flows and reputation.

Partner Risks

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

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

SAGD Technology

Current technologies used for the recovery of bitumen is energy intensive, including SAGD which requires significant consumption of natural gas in the production of steam used in the recovery process. The amount of steam required in the recovery process varies and therefore impacts costs. The performance of the reservoir affects the timing and levels of production using SAGD technology. A large increase in recovery costs could cause certain projects that rely on SAGD technology to become uneconomical, which could have a negative effect on our business, financial condition, results of operations, and cash flows. There are risks associated with growth and other capital projects that rely largely or partly on new technologies, the incorporation of such technologies into new or existing operations, and acceptance of new technologies in the market. The success of projects incorporating new technologies cannot be assured.

Technology, Information Systems and Data Privacy

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

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

Any such incident, breach, or disruption of our or our service providers' technology systems or services, or other vendor technology systems or services (including where a threat actor is successful in bypassing our cyber-security measures and business process controls), could result in loss or the exposure of internal, confidential, financial, proprietary, personal or other sensitive information. These could result in financial losses, remediation and recovery costs, legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, operational disruption, site shut-down, leaks or other negative consequences, including damage to our reputation, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Data protection and privacy is governed by a complex legal and regulatory framework that is rapidly evolving in the areas in which we operate. We must comply with increasingly complex and rigorous, and sometimes conflicting, regulatory standards enacted to protect business and personal information in Canada, the United States, and elsewhere. These laws impose additional obligations on companies regarding the handling of personal information and provide certain individual privacy rights to persons whose information is collected, used, stored, processed or disclosed. Compliance with existing, proposed and recently enacted laws and regulations can be costly and time consuming, and any failure to comply with these regulatory standards could subject us to legal and reputational risks. Misuse of or failure to secure personal information could also result in violation of data privacy laws and regulations, proceedings against the Company by governmental entities or others, imposition of fines by governmental authorities and damage to our reputation and credibility and could have a negative impact on financial condition. Compliance with such legislation may also result in increased operating costs. Failure to comply with such legislation may result in severe fines and penalties, which may adversely impact our reputation, financial condition, results of operations and cash flows.

Security and Terrorist Threats

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

Activism and Disruptions to Operations

Increasing public engagement and activism generally, and in connection with the energy industry and the continued development of fossil fuel-based energy, has, from time to time, resulted in temporary disruptions to oil and gas development, operations and transportation. Such opposition has not yet materially impacted our facilities directly; however, activist groups and individuals may engage in protests, demonstrations or blockades that may disrupt our facilities or operations, or to facilities or operations on which we rely. Any such disruptions may have an adverse impact on our business, operations, financial condition or reputation.

While we have systems, policies and procedures designed to prevent or limit the effects of such disruptive events, there can be no assurance that these measures will be sufficient and that such disruptions will not occur or, if they do occur, that they will be adequately addressed in a timely manner.

Leadership and Talent

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

Litigation and Claims

From time to time, we may be involved in demands, disputes, proceedings, arbitrations and/or litigation ("Claims") arising out of or related to our operations and other contractual relationships. Claims may be material. Due to the nature of our operations we may be involved with various types of Claims including, but not limited to, failure to comply with applicable laws and regulations including potential claims that we have violated laws related to discrimination and harassment, health and safety, the environment, breach of contract, negligence, product liability, antitrust, bribery and other forms of corruption, tax, securities class actions, derivative actions, patent infringement, privacy, employment, labour relations, personal injury and other Claims. We may be required to incur substantial expenses or devote significant resources in respect of any such Claims, which could result in unfavourable judgments, decisions, fines, sanctions, monetary damages, temporary or permanent suspensions of operations, or the inability to engage in certain transactions. The outcome of such claims can be difficult to assess or quantify and may have a material adverse effect on our business, reputation, financial condition and results of operations and cash flows. In addition, we may be subject to or impacted by climate change related litigation, including class actions. See "Climate Change Related Litigation" below.

Indigenous Land and Rights Claims

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

Some Indigenous groups have established or asserted Indigenous rights and may have treaty rights to portions of Canada. There are outstanding Indigenous and treaty rights claims, which may include land title claims, on lands where we operate, and such claims, if successful, could have a material adverse impact on our operations or pace of growth. No certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims. Some Indigenous groups have also brought private nuisance claims against project operators for infringement of Indigenous rights. Such claims, if successful, could adversely affect our business, results of operations, financial condition or reputation.

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

In addition, the Canadian federal government passed legislation which requires it to take all necessary measures to implement the United Nations Declaration on the Rights of Indigenous Peoples ("UNDRIP"). Other Canadian jurisdictions have also introduced or passed similar legislation, or begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP's implementation by government is ongoing and uncertain; additional processes have been and are expected to continue to be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements.

Governmental Risk

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

Regulatory Risk

The oil and gas industry and refining industry in general and our operations in particular are subject to regulation and intervention under international, federal, provincial, territorial, state, regional and municipal legislation in the countries in which we conduct operations, development or exploration in matters such as, but not limited to: land tenure; permitting of production projects; royalties; taxes (including income taxes); government fees; production rates; environmental protection; protection of certain species or lands; cumulative effects and/or impacts from all types of industrial development; provincial and federal land and water use designations or management plans; the reduction of GHG and other emissions; the export of crude oil, natural gas and other products; the transportation of crude-by-rail, pipeline or marine transport; generation, handling, storage, transportation, treatment and disposal of hazardous substance; the awarding or acquisition of exploration, development and production rights, oil sands or other interests; the imposition of specific drilling obligations; control over the development, abandonment and reclamation of fields (including restrictions on production) and/or facilities; and possibly expropriation or cancellation of contract rights. The petroleum refining sector in the U.S. has been and continues to be subject to intensive environmental regulations, oversight, and enforcement from both federal and state governments. Third-party non-governmental organizations ("NGOs") and citizen groups can also directly influence environmental regulations and have been active against the U.S. refinery sector for many years. Any changes to the regulatory regime, including the implementation of new regulations or the modification or changed interpretation of existing regulations could impact our existing and planned projects requiring increased capital investment, operating expenses or compliance costs, which could adversely impact our financial condition, results of operations, cash flows and reputation. To mitigate these risks, we have regulatory programs that cover stakeholder engagement, air emissions, water quantity and quality, deep disposal well operations, solid and hazardous waste management, spills, and legacy contamination issues.

Regulatory Approvals

Our operations require us to obtain approvals from various regulatory authorities and there are no guarantees that we will be able to obtain and maintain, or obtain and maintain on acceptable conditions, all necessary licenses, permits and other approvals that may be required to carry out certain exploration, development and operating activities on our properties. In addition, obtaining certain approvals from regulatory authorities can involve, among other things, stakeholder consultation, Indigenous consultation, consensus seeking and collaboration, environmental impact assessments and public hearings. Regulatory approvals obtained may be subject to the satisfaction of certain conditions including, but not limited to: security deposit obligations; ongoing regulatory oversight of projects; mitigating or avoiding project impacts; environmental and habitat assessments; and other commitments or obligations. Failure to obtain applicable regulatory approvals or satisfy any conditions on a timely basis or satisfactory terms could result in increased costs, project delays, abandonment and/or restructuring of projects.

Abandonment and Reclamation Cost Risk

We are subject to oil and gas asset abandonment, remediation and reclamation ("A&R") liabilities for our operations, development and exploration, including those imposed by regulation under federal, provincial, territorial, state, regional and municipal legislation in the jurisdictions in which we conduct operations, development or exploration.

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

In Alberta and Saskatchewan, the A&R liability regimes include orphan well funds that are funded through a levy imposed on licensees, including Cenovus, based on the licensees' proportionate share of deemed A&R liabilities for oil and gas facilities, wells and unreclaimed sites. The aggregate value of the A&R liabilities assumed has increased in recent years and will remain at elevated levels until a significant number of orphaned wells are decommissioned utilizing the orphan funds. The Alberta and Saskatchewan regulators may seek additional funding for such liabilities from industry participants, including Cenovus.

The AER has discretion in the consideration of licence eligibility, transfer applications and the requirement to post security or carry out A&R work. Permit holders that are considered high risk and/or have relatively high levels of A&R obligations within their asset bases may be negatively impacted, including our potential counterparties. This may result in future insolvencies and additional orphaned assets. In addition, this may impact our ability to transfer our licences, approvals or permits, and may result in increased costs and delays or require changes to our abandonment of projects and transactions.

We have an ongoing environmental monitoring program of owned and leased retail locations, and former owned or leased retail locations where we have retained environmental liability, and perform remediation where required to comply with contractual and legal obligations. The costs of such remediation depend on a number of uncertain factors such as the extent and type of remediation required. Due to uncertainties inherent in the estimation process, it is possible that existing estimates may need to be revised and that conditions may exist at various retail locations that require future expenditures. Such future costs may not be determinable due to the unknown timing and extent of corrective actions that may be required.

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

Royalty Regimes

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

Canada-United States-Mexico Agreement (“CUSMA”)

On July 1, 2020, the new CUSMA entered into force, which is known in the United States as the United States-Mexico-Canada Agreement (or “USMCA”), replacing the North American Free Trade Agreement (“NAFTA”). The investor-state dispute settlement provisions that were present within NAFTA will no longer be available in the CUSMA to protect future investments of Canadians in the U.S. or U.S. investments in Canada. For three years after the termination of NAFTA, existing legacy investments will maintain their access to the investor-state dispute settlement under NAFTA Chapter 11. However, starting July 1, 2023, such legacy disputes and disputes related to investments established or acquired on after July 1, 2020 will fall to the appropriate courts in the United States, or Cenovus may seek intervention of the Canadian government to pursue relief through state-to-state dispute resolution.

Labour Risk

We depend on unionized labour for the operation of certain facilities and may be subject to adverse employee relations and labour disputes, which may disrupt operations at such facilities. As of December 31, 2022, approximately 7 percent of our employees are represented by unions under collective bargaining agreements, which includes just over 50 percent of our U.S. workforce. At unionized worksites, there is risk that strikes or work stoppages could occur. Any strike or work stoppage (for any reason, including a health and safety shutdown) may have a material adverse effect on our business, safety, reputation, financial condition, results of operations and cash flows.

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

Moreover, employees who are not currently represented by unions may seek union representation in the future and efforts may be made from time to time to unionize other portions of our workforce. Future unionization efforts or changes in legislation and regulations may result in labour shortages, higher labour costs, as well as wage, benefit, and other employment consequences, especially during critical maintenance and construction periods, all of which may increase our costs, reduce our revenues or limit our operational flexibility.

International Developments and Geopolitical Risk

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

Political developments impacting international trade, including trade disputes, increased tariffs and sanctions, particularly between the U.S. and China and Canada and China, may negatively impact markets and cause weaker macroeconomic conditions or drive political or national sentiment, weakening demand for crude oil, natural gas and refined products. For example, U.S. government trade policy has resulted in, and could result in more, U.S. trading partners adopting responsive trade policy and may make it more difficult or costly for us to operate in and export our products to those countries.

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

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

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

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

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

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

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

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

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

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

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

The War in Ukraine

Uncertainty regarding the duration and ultimate effects of the Russia – Ukraine war may result in major disruptions in oil and natural gas supply and continuing commodity price volatility. Further, Canada, the U.S. and other countries have imposed significant sanctions on Russia and many Russian officials, agencies, NGOs, companies and individuals some of whom are involved in the energy business or are significant buyers of crude oil or other hydrocarbons. Cenovus does not conduct business with sanctioned entities or persons and has no operations or significant business in Russia, Ukraine or other regions affected by these sanctions. Consequently, these sanctions have not had a material impact on Cenovus or our business. However, the scope and impact of the war, and any related international action, including any future sanctions, cannot be accurately predicted and may have a material adverse impact on our business, prospects, financial condition, results of operations, cash flows, and reputation.

Climate-Related Risks

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

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

Transition Risks – Policy & Legal

Climate Change Regulation

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

The Government of Canada has announced the carbon tax will increase to $170/tonne CO2e by 2030. To reach that level, the price imposed on carbon will rise from the 2022 rate of $50/tonne CO2e by $15/tonne CO2e each year until 2030. To the extent a province's carbon pricing system does not meet the federal stringency requirements, the federal "backstop" regulations apply. Most of our Canadian-based large emitting facilities operate in British Columbia, Alberta, Saskatchewan, or Newfoundland and Labrador where provincial carbon pricing regulations apply. These provincial programs are expected to continue to be deemed equivalent to the federal carbon pricing system.

In July 2022, the Government of Canada released an oil and gas emissions cap discussion document. The government is currently considering the form that any future regulation designed to meet the goals of the emission cap will take. The options proposed in the discussion document are a cap-and-trade system (under the Canadian Environmental Protection Act (“CEPA”) that sets a regulated limit on emissions from the sector or modifying the pollution pricing benchmark requirements to create price-driven limits on emissions from the oil and gas sector. The government is expected to release details on the form of the emissions cap in 2023. The Government has also committed to engaging provinces, territories, and Indigenous organizations in an interim review of the benchmark by 2026 after which, regulatory measures designed to meet the goals of the emissions cap could come into force.

The Government of Canada has implemented regulation to enable the reduction of methane emissions from the crude oil and natural gas sector by 40 percent to 45 percent from 2012 levels by 2025. Regulatory requirements for fugitive equipment leaks and venting from well completion and compressors came into force on January 1, 2020. Further restrictions on facility production venting restrictions and venting limits for pneumatic equipment came into force on January 1, 2023. Certain provinces have since implemented provincial methane regulations that have been found to be equivalent with federal requirements. The Government of Canada has announced an additional target to reduce oil and gas methane emissions by at least 75 percent below 2012 levels by 2030. In November 2022 the Government of Canada published for comment, a proposed regulatory framework to support their methane emissions reduction target. The proposal includes source by source requirements as well as additional performance-based requirements and is to be regulated under CEPA.

The U.S. does not have federal legislation establishing targets for the reduction of, or setting individualized limits on, GHG emissions from our U.S. facilities. The Renewable Fuel Standard ("RFS") was created to reduce GHG emissions and risks from that program are described below. Additionally, the federal Environmental Protection Agency ("EPA") has and may continue to promulgate regulations concerning the reporting and control of GHG emissions. Since 2010, the EPA's Greenhouse Gas Reporting Program ("GHGRP") requires any facility releasing more than 25,000 tonnes of CO2e emissions per year to report those emissions on an annual basis. In addition to reporting direct CO2e emissions, the GHGRP requires refineries to estimate the CO2e emissions from the potential subsequent combustion of the refinery's products. In early 2021, the U.S. rejoined the Paris Agreement and subsequently announced a 2030 target to reduce GHG emissions by 50 percent to 52 percent from 2005 levels. It is expected that this target will be met largely through clean energy incentives introduced under the Inflation Reduction Act as opposed to regulatory measures.

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

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

Low Carbon Fuel Standards

Existing and proposed environmental legislation and regulation developed by certain U.S. states, Canadian provinces and territories, the Canadian federal government and members of the European Union, regulating carbon fuel standards could result in increased costs and reduced revenue for us. The potential regulation may negatively affect the marketing of our bitumen, crude oil or refined products, and may require us to purchase emissions credits in order to effect sales in such jurisdictions.

Environment and Climate Change Canada published final regulations in 2022 for the Clean Fuel Standard under the Canadian Environmental Protection Act, 1999. The Clean Fuel Standard will replace the current Renewable Fuels Regulations, which requires producers and importers of transportation fuels to acquire a certain number of compliance units commensurate with the volumes of fuel they produce or import. The new regulatory framework will impose lifecycle carbon intensity requirements for certain liquid fuels and establish rules relating to the trading of compliance credits. Carbon intensity requirements under the Clean Fuel Standard regulation become more stringent over time and are differentiated between different types of fuels to reflect the associated emissions reduction potential. Regulated parties have some flexibility with respect to how to achieve lower-carbon fuels in Canada. The cost of compliance will depend on a number of factors including, but not limited to, credit market supply and demand dynamics, development costs associated with low carbon fuels, and technology developments that could reduce demand for liquid transportation fuels. The Clean Fuel Standard regulation has the potential to impact our business, financial condition, results of operations and cash flows, though at this time it is difficult to predict or quantify any such impacts.

Renewable Fuel Standards

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

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

Light-Duty Vehicle Greenhouse Gas Emission Standards

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

Climate Change Related Litigation

In recent years there has been an increase in climate change related demands, disputes, and litigation in various jurisdictions including the U.S. and Canada, asserting various claims, including that energy producers contribute to climate change, that such entities are not reasonably managing business risks associated with climate change, and that such entities have not adequately disclosed business risks of climate change. While many of the climate change related actions are in preliminary stages of litigation, and in some cases assert novel or untested causes of action, there can be no assurance that legal, societal, scientific and political developments will not increase the likelihood of successful climate change related litigation against energy producers, including Cenovus. The outcome of any such litigation is uncertain and may materially impact our business, financial condition or results of operations. We may also be subject to adverse publicity associated with such matters, which may negatively affect public perception and our reputation, regardless of whether we are ultimately found responsible. We may be required to incur significant expenses or devote significant resources in defense against any such litigation.

Transition Risks – Technology

We depend on, among other things, the availability and scalability of existing and emerging technologies to meet our business goals, including our ESG targets. Limitations related to the development, adoption and success of these technologies or the development of disruptive technologies could have a negative impact on our long-term business resilience.

Transition Risks – Market

Demand and Commodity Prices

The recent increase in focus on the timing and pace of the transition to a lower-carbon economy and resulting trends will likely affect global energy demand and usage, including the composition of the types of energy generally used by industry and individual consumers. Under certain aggressive low-carbon scenarios, potential demand erosion could contribute to commodity price fluctuations and structural commodity price declines. However, it is not currently possible to predict the timelines for, and precise effects of, this transition to a potential lower-carbon economy, which will depend on a multitude of factors including increased decarbonization policies, the ability to develop adequate alternative sources of energy, technology development and adaptation including in the area of transportation electrification, the ability to conceptualize, develop and commercialize technologies for the production, storage and distribution of adequate supplies of alternative energy, consumption patterns, global growth, industrial activity, weather patterns and climate conditions, including as a result of climate change. All of these factors are beyond our control and could result in a high degree of price volatility for each of crude oil, natural gas, NGLs, electricity and refined products.

Market Access

Opposition to new and expanded pipeline projects have been influenced by, among other things, concerns about GHG emissions associated with fossil fuel-based energy development and end-use combustion of fuels. Additional concerns about pipeline spills can create opposition to pipeline projects at a local level. Our inability to optimize market access for either the delivery of our production or refining feedstock may negatively impact our business, financial condition, cash flows and results of operations.

Access to Capital and Insurance

Capital markets are adjusting to the risks that climate change poses and as a result, our ability to access capital and secure adequate or prudent insurance coverage may also be adversely affected in the event that financial institutions, investors, credit rating agencies, lenders and/or insurers adopt more restrictive decarbonization policies. Certain insurance companies have taken actions or announced policies to limit available coverage for companies which derive some or all of their revenue from the oil sands sector. As a result of these policies, premiums and deductibles for some or all of our insurance policies could increase substantially and/or coverage may be reduced or become unavailable. As a result, we may not be able to renew our existing policies or procure other desirable insurance coverage, either on commercially reasonable terms, or at all. Additionally, certain financial institutions have taken actions or announced policies related to decarbonization of their loan portfolios. As a result, costs of financing could increase over time and we may not be able to refinance our debt, renew or extend credit facilities or procure additional financing at reasonable costs and interest rates, or at all. The future development of our business may be dependent upon our ability to obtain additional capital, including debt and equity financing. See "Credit, Liquidity and Availability of Future Financing" above.

Accuracy of Climate Scenarios and Assumptions

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

Shareholder Activism

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

Transition Risks – Reputation and Public Perception of the Oil and Gas Sector

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

For example, legislation or policies that limit the purchase of crude oil or bitumen produced from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for this crude oil, reduce its price and may result in stranded assets or an inability to further develop oil resources. See "Reputation Risk" below.

Climate Change – Physical Risks

Systemic climatic changes or extreme climatic conditions may also have material adverse effects on our business, reputation, financial condition, results of operations and cash flows. Weather and climate affect demand, and therefore, the predictability of the demand for energy is affected to a large degree by the predictability of weather and climate. In addition, our exploration, refining, pipeline, production and construction operations, and the operations of major customers and suppliers, can be affected by acute physical climate risks, such as floods, forest fires, earthquakes, hurricanes, storms, extreme temperatures and other extreme weather events or natural disasters. This may result in cessation or diminishment of production or throughput, delay of exploration and development activities or delay of plant construction.

Climate change may also increase the frequency of severe weather conditions that may adversely impact our operations, business and financial results. For example, our Atlantic operations may be impacted by severe weather conditions, including winds, flooding and variable temperatures, which are contributing to the melting of northern ice and increased creation of icebergs. Icebergs off the coast of Newfoundland and Labrador pose a risk to Atlantic oil production facilities. An operational incident as a result of severe weather conditions, has the potential to result in spills, asset damage, and production or refining disruption. Climate change may result in an increased level of risk resulting in increased or additional mitigation requirements.

Our other operations are also subject to chronic physical risks such as a shorter timeframe for our winter drilling program, changes in the water table and reduced access to water due to drought conditions. A systemic change in temperature or precipitation patterns could result in more challenging conditions for the construction of ice roads, execution of our winter drilling program and reclamation activities and could reduce the availability of water due to the increasing likelihood of drought conditions.

Environmental Regulation Risks

All phases of our operations are subject to environmental regulation pursuant to a variety of federal, provincial, territorial, state, regional and municipal laws, and regulations in the jurisdictions in which we operate (collectively, the “environmental regulations”). Environmental regulations provide that exploration areas, wells, facility sites, refineries and other properties and practices associated with our operations be constructed, operated, maintained, abandoned, reclaimed, and undertaken in accordance with the requirements set out therein. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications.

We anticipate that further changes in environmental legislation will occur, which may result in approval delays for critical licences and permits, stricter standards and enforcement, larger fines and liabilities, the introduction of emissions limits, increased compliance costs and increased costs for closure, controls on land and resource access, reclamation, and ecological restoration. The complexities of changes in environmental regulations make it difficult to predict the potential future impact to our business.

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

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

Canadian Species at Risk Act

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

Canadian Federal Air Quality Management System

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

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

Review of Environmental and Regulatory Processes

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

The Impact Assessment Agency of Canada leads and coordinates federal impact assessments for all designated projects within Canada. Assessment considerations beyond the environment expressly include health, economic, social, and gender impacts, as well as considerations related to sustainability and Canada’s climate change commitments. For as long as the Alberta provincial government maintains the cap on oil sands emissions in Alberta and the cap has not been reached, our in-situ oil sands projects should be exempted from the application of the federal impact assessment system, provided a number of additional conditions are met. However, other types of projects would undergo a federal assessment, including those within our Atlantic operations.

Water Regulation

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

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

Hydraulic Fracturing

Certain stakeholders have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources and suggest that additional federal, provincial, territorial, state, regional and/or municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process.

In addition, some areas of British Columbia and Alberta have experienced increased localized frequency of seismic activity which has been associated with oil and gas operations. Although the occurrence of seismicity in relation to oil and gas operations is generally very low, it has been linked to deep disposal of wastewater in the U.S. and has been correlated with hydraulic fracturing in conjunction with horizontal drilling techniques in Western Canada, which has prompted legislative and regulatory initiatives intended to address these concerns.

New laws, regulations or permitting requirements regarding hydraulic fracturing may lead to limitations or restrictions to oil and gas development activities, operational delays, increased compliance costs, additional operating requirements, or increased third-party or governmental claims resulting in increased cost of doing business as well as impacting the amount of natural gas and oil that we are ultimately able to produce from our reserves.

Cenovus ESG Focus Areas, Targets and Ambitions

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

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

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

Climate and GHG Emissions Target and Ambition

We have set a target to reduce our absolute scope 1 and 2 GHG emissions by 35 percent by year-end 2035 from 2019 levels and have a long-term ambition to achieve net zero emissions from our operations by 2050. Our ability to meet our 2035 GHG reduction target and 2050 net zero ambition are subject to numerous risks and uncertainties and our actions taken in implementing such target and ambition may also expose us to certain additional and/or heightened financial and operational risks. Furthermore, our long-term ambition of reaching net zero emissions by 2050 is inherently less certain due to the longer timeframe and certain factors outside of our control, including the commercial application of future technologies that may be necessary for us to achieve this long-term ambition.

A reduction in GHG emissions relies on, among other things, our ability to develop, access and implement commercially viable and scalable emission reduction strategies and related technology and products. In addition, there are other operational risks that may hinder our ability to successfully meet our GHG emission targets and goals, including: unexpected impediments to, or effects of, the implementation of methane abatement and electrification initiatives in our Conventional segment; the purchase of renewable electricity; the unavailability of, or limited benefits from, technology that is expected to be commercially viable in the near term and its associated future benefits, including SAGD enhancement technologies, such as solvent-aided process and solvent-driven process technologies, carbon capture, utilization and storage technology and downhole technology improvements; and a failure to capture the anticipated benefits of continued technological development, and industry collaboration and innovation to find solutions to reduce costs and GHG emissions. If we are unable to implement these strategies and technologies as planned without negatively impacting our expected operations or cost structure, or such strategies or technologies do not perform as expected, we may be unable to meet our 2035 GHG reduction target or 2050 net zero emissions ambition on the planned timelines, or at all.

In addition, achieving our 2035 GHG reduction target and 2050 net zero ambition relies on a stable regulatory framework, support from government, financial or otherwise, and will require capital expenditures and company resources, with the potential that actual costs may differ from our original estimates and the differences may be material. Furthermore, the cost of investing in emissions-reduction technologies, and the resultant change in the deployment of resources and focus, could have a negative impact on our business, financial condition, results of operations and cash flows.

Water Stewardship Targets

Our ability to reduce freshwater intensity by 20 percent in oil sands and in thermal operations from 2019 levels by year-end 2030 or maintain such improvements will depend on the commercial viability and scalability of relevant water reduction strategies and related steam and water usage technology and products. There are risks associated with relying largely or partly on new technologies, the incorporation of such technologies into new or existing operations and acceptance of new technologies in the market. In the event we are unable to effectively and efficiently deploy the necessary technology, or such strategies or technologies do not perform as expected, achieving our stated target of reducing our water intensity could be interrupted, delayed or abandoned.

Biodiversity Targets

Our biodiversity targets include the goal to reclaim 3,000 decommissioned well sites by year-end 2025 and to restore more habitat than we use within the Cold Lake caribou range by year-end 2030. Our ability to meet these targets is subject to various environmental and regulatory risks, which could impose significant costs, restrictions, liabilities, and obligations on us. See “Abandonment and Reclamation Cost Risk” above. In addition, an increase in operating costs, changes to market conditions and access to additional capital, if needed, could result in our inability to fund, and ultimately meet, our biodiversity targets on the current timelines, or at all.

Indigenous Reconciliation Targets

Our Indigenous reconciliation targets to spend a minimum of $1.2 billion with Indigenous owned or operated businesses between 2019 and year-end 2025 and attain Progressive Aboriginal Relations gold certification from the Canadian Council for Aboriginal Business by year-end 2025 are subject to a number of financial, operational and efficiency risks relating to actions taken in implementing such targets.

In addition, a failure or delay in achieving our Indigenous reconciliation targets may adversely affect our relationship with neighboring Indigenous businesses and communities and our broader reputation. If we are unable to maintain a positive relationship with Indigenous communities near our operations, our progress and ability to develop and operate properties in line with our current business and operational strategies may be adversely impacted.

Inclusion and Diversity Targets

Our inclusion and diversity focus area includes a target of women in leadership roles of at least 30 percent by year-end 2030 as well as an aspiration for our Board to have at least 40 percent representation from women, Indigenous peoples, persons with disabilities and members of visible minorities among non-management directors. Efforts to meet and maintain such targets may increase the time and costs associated with appointing and replacing key personnel. Further, an inability to hire or promote qualified candidates or a failure or delay in achieving our targets may influence our reputation with our stakeholders, attract litigation and impact recruitment initiatives. There are also risks associated with the collection of certain personal data in furtherance of these targets.

Reputation Risk

We rely on our reputation to build and maintain positive relationships with investors and other stakeholders, to recruit and retain staff, and to be a credible, trusted company. Any actions we take that influence public or key stakeholder opinions have the potential to impact our reputation, which may adversely affect our share price, development plans and ability to continue operations. There is increasing opposition from climate change activist organizations and the public towards oil and gas operations. See “Transition Risks – Reputation and Public Perception of the Oil and Gas Sector” above.

Other Risks

Dilutive Effect

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

It is also expected that, from time to time, we will grant additional equity awards to our employees and directors under our compensation plans. These additional equity awards will have a further dilutive effect on our earnings per share, which could also negatively affect the market price of Cenovus common shares and may adversely impact the value of our shareholders' investments.

Risks Relating to Acquisitions

We have completed, and may complete in the future, one or more acquisitions for various strategic reasons. Our ability to achieve the benefits of any acquisition will depend upon the actions of our counterparties; our ability, and the ability of our counterparties, to obtain the necessary shareholder, regulatory and third-party approvals, as applicable, and satisfy all conditions to closing; the risks inherent in the operation of the assets being acquired prior or subsequent to closing; the effectiveness of our diligence investigations; the physical condition of the assets upon closing; our ability to obtain indemnities and/or fund ongoing maintenance, repair and operation costs of the assets acquired; our ability to assess the integrity and reliability of the assets being acquired; our ability to successfully consolidate functions and integrate operations, procedures and personnel in a timely and efficient manner and to realize the anticipated growth opportunities and synergies from combining the acquired assets and operations with our existing assets and operations. The integration of acquired assets and operations requires the dedication of management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during the process. The integration process may result in the disruption of ongoing business and customer relationships that may adversely affect our ability to achieve the anticipated benefits of such acquisitions. Acquiring assets requires the assessment of their characteristics, including, among other things, estimated recoverable reserves, future production and throughput, commodity prices, revenues, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain and, as such, the acquired properties may not produce as expected, may not have the anticipated reserves and may be subject to increased costs and liabilities. Although the acquired assets are reviewed prior to completion of an acquisition, such reviews are not capable of identifying all existing or potentially adverse conditions. This risk may be magnified where the acquired assets are in geographic areas where we have not historically operated. Further, we may not be able to obtain or realize upon contractual indemnities from a seller for liabilities created prior to an acquisition and we may be required to assume the risk of the physical condition of the properties that may not perform in accordance with its expectations or require repair or other expenditures, the scope of which may be uncertain, result in increased costs and affect our ability, and timeline, to realize the benefits of the acquisition.

Risks Relating to Dispositions

We have completed, and may complete in the future, one or more dispositions for various strategic reasons. Various factors could materially affect our ability to dispose of assets in the future, including stock exchange, regulatory, third-party and corporate approvals, counterparties' ability to fulfill their obligations under agreements to affect dispositions, commodity prices, the availability of purchasers willing to purchase certain assets at prices and on terms acceptable to us, associated asset retirement obligations, due diligence, favourable market conditions, and the assignability of joint venture, partnership or other arrangements. These factors may also reduce the proceeds or value to our business. We may also retain certain liabilities for or agree to indemnification obligations in a sale transaction. The magnitude of any such retained liabilities or indemnification obligations may be difficult to quantify at the time of the transaction and could ultimately be material. Further, certain third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after the sale of certain assets, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the purchaser of the assets fails to perform its obligations. Should any of the risk associated with dispositions materialize, it could have an adverse effect on our business, financial condition or reputation.

Risks Related to Significant Shareholders of Cenovus

As of December 31, 2022, Hutchison Whampoa Europe Investments S.à r.l. ("Hutchison") and L.F. Investments S.à r.l. ("L.F. Investments") owned 16.6 percent and 12.1 percent of our common shares, respectively. The sale into the market of Cenovus common shares held by either Hutchison or L.F. Investments, whether through open market trades on the TSX or NYSE, through privately arranged block trades or pursuant to prospectus offerings made in accordance with the respective registration rights agreement that each of Hutchison and L.F. Investments has entered into with Cenovus, or market perception regarding Hutchison's or L.F. Investments' intention to sell Cenovus common shares, could adversely affect market prices for our common shares. While Hutchison and L.F. Investments are each subject to certain voting covenants pursuant to the terms of a standstill agreement they each entered into with Cenovus, each of Hutchison and L.F. Investments may be able to impact certain matters requiring Cenovus shareholder approval.

Market for Cenovus Warrants

There can be no assurance that an active public market for Cenovus Warrants will be sustained. If such a market is sustained, the market price of the Cenovus Warrants may be adversely affected by a variety of factors relating to Cenovus's business, including, but not limited to, fluctuations in our operating and financial results, the results of any public announcements made by us and our failure to meet analysts' expectations. In addition, the market price of the Cenovus common shares will significantly affect the market price of the Cenovus Warrants. This may result in significant volatility in the market price of the Cenovus Warrants and may negatively impact the value of the Cenovus Warrants.

Contingent Payments Payable relating to Sunrise Acquisition

In connection with the Sunrise Acquisition, we agreed to make contingent payments to BP Canada under certain circumstances. The amount of contingent payments vary depending on the Canadian dollar WCS price from time to time during the two-year period following the closing of the Sunrise Acquisition (August 31, 2022), and such payments are cumulatively capped at $600 million. This payment may be material in any given reporting period as the entire maximum payment could be reached in a single quarter and could have an adverse impact on our results of operations and financial condition.

Tax Laws

Income tax laws and regulations and other laws and government incentive programs may in the future be changed or interpreted in a manner that adversely affects us, our financial results and our shareholders. Tax authorities having jurisdiction over Cenovus may disagree with the manner in which we calculate our tax liabilities such that its provision for income taxes may not be sufficient, or such authorities could change their administrative practices to Cenovus's detriment or to the detriment of our shareholders. In addition, all of our tax filings are subject to audit by tax authorities who may disagree with such filings in a manner that adversely affects Cenovus and our shareholders.

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

In Canada, in the 2022 Fall Economic Statement released by the Department of Finance, a new tax on share buybacks by public corporations was proposed. Under the proposal, which would come into force on January 1, 2024, a two percent corporate-level tax would apply on the "net value" of all types of shares buybacks by public corporations in Canada. While there are few details available on the proposed tax, we will continue to monitor and assess any potential adverse impacts as more information becomes available.

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

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATION UNCERTAINTIES AND ACCOUNTING POLICIES

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

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 the Company's Consolidated Financial Statements.

Joint Arrangements

The classification of a joint arrangement that is held in a separate vehicle as either a joint operation or a joint venture requires judgment. Cenovus has a 50 percent interest in the following jointly controlled entities:

- WRB Refining LP ("WRB").
- BP-Husky Refining LLC ("Toledo").

It was determined that Cenovus has the rights to the assets and obligations for the liabilities of WRB and Toledo. As a result, the joint arrangements are classified as joint operations and the Company's share of the assets, liabilities, revenues and expenses are recorded in the Consolidated Financial Statements.

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

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

- The original intention of the joint arrangements was to form an integrated North American heavy oil business. Partnerships are "flow-through" entities.
- The agreements require the partners to make contributions if funds are insufficient to meet the obligations or liabilities of the corporation and partnerships. The past development of Sunrise, and the past and future development of WRB and Toledo, is dependent on funding from the partners by way of capital contribution commitments, notes payable and loans.
- WRB has third-party debt facilities to cover short-term working capital requirements. Up until November 2022, Sunrise also had third-party debt facilities.
- Sunrise was operated like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants in accordance with the partnership agreement. WRB and Toledo have very similar structures modified to account for the operating environment of the refining business.
- Cenovus, Phillips 66 and BP, as operators, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage, on the partners' behalf as the agreements prohibit the partners from undertaking these roles themselves. In addition, the joint arrangements do not have employees and, as such, are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

Exploration and Evaluation Assets

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

Identification of Cash-Generating Units

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

Recoveries from Insurance Claims

The Company uses estimates and assumptions on the amount recorded for insurance proceeds that are reasonably certain to be received. Accordingly, actual results may differ from these estimated recoveries.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that, if changed, could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

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

Changes to assumptions could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Crude Oil and Natural Gas Reserves

There are a number of inherent uncertainties associated with estimating crude oil and natural gas reserves. Reserves estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test recoverable amount and DD&A expense of the Company's crude oil and natural gas assets in the Oil Sands, Conventional and Offshore segments. The Company's reserves are evaluated annually and reported to the Company by its IQREs.

Recoverable Amounts

Determining the recoverable amount of a CGU or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. For the Company's upstream assets, these estimates include forward commodity prices, expected production volumes, quantity of reserves and resources, discount rates, future development and operating expenses. Recoverable amounts for the Company's manufacturing assets, crude-by-rail terminal and related ROU assets use assumptions such as throughput, forward commodity prices, discount rates, operating expenses and future capital expenditures. Recoverable amounts for the Company's real estate ROU assets use assumptions such as real estate market conditions which includes market vacancy rates and sublease market conditions, price per square footage, real estate space availability and borrowing costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

Decommissioning Costs

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

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

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

Income Tax Provisions

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

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

Changes in Accounting Policies

There were no new or amended accounting standards or interpretations adopted during the year ended December 31, 2022.

New Accounting Standards and Interpretations not yet Adopted

There are new accounting standards, amendments to accounting standards and interpretations that are effective for annual periods beginning on or after January 1, 2023, and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2022. These standards and interpretations are not expected to have a material impact on the Company's Consolidated Financial Statements or the Company's business.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at December 31, 2022. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of ICFR. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2022.

The effectiveness of our ICFR was audited as at December 31, 2022 by PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, as stated in their Report of Independent Registered Public Accounting Firm, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2022.

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.

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2022

REPORT OF MANAGEMENT

Management's Responsibility for the Consolidated Financial Statements

The accompanying Consolidated Financial Statements of Cenovus Energy Inc. are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in Canadian dollars in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and include certain estimates that reflect Management's best judgments.

The Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee which is made up of five independent directors. The Audit Committee has a written mandate that complies with the current requirements of Canadian securities legislation and the United States Sarbanes – Oxley Act of 2002 and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange. The Audit Committee met with Management and the independent auditors on at least a quarterly basis to review and recommend the approval of the interim Consolidated Financial Statements and Management's Discussion and Analysis to the Board of Directors prior to their public release as well as annually to review the annual Consolidated Financial Statements and Management's Discussion and Analysis and recommend their approval to the Board of Directors.

Management's Assessment of Internal Control Over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The internal control system was designed to provide reasonable assurance to Management regarding the preparation and presentation of the Consolidated Financial Statements.

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.

Management has assessed the design and effectiveness of internal control over financial reporting as at December 31, 2022. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of internal control over financial reporting. Based on our evaluation, Management has concluded that internal control over financial reporting was effective as at December 31, 2022.

PricewaterhouseCoopers LLP, an independent registered public accounting firm, was appointed to audit and provide independent opinions on both the Consolidated Financial Statements and internal control over financial reporting as at December 31, 2022, as stated in their Report of Independent Registered Public Accounting Firm dated February 15, 2023. PricewaterhouseCoopers LLP has provided such opinions.

/s/ Alexander J. Pourbaix
Alexander J. Pourbaix
President & Chief Executive Officer
Cenovus Energy Inc.

/s/ Jeffrey R. Hart
Jeffrey R. Hart
Executive Vice-President & Chief Financial Officer
Cenovus Energy Inc.

February 15, 2023

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Cenovus Energy Inc.

Opinions on the Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying consolidated balance sheets of Cenovus Energy Inc. and its subsidiaries (together, the Company) as of December 31, 2022 and 2021, and the related consolidated statements of earnings (loss), comprehensive income (loss), equity and cash flows for each of the three years in the period ended December 31, 2022, including the related notes (collectively referred to as the Consolidated Financial Statements). We also have audited the Company's internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the Consolidated Financial Statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and its financial performance and its cash flows for each of the three years in the period ended December 31, 2022 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2022, based on criteria established in Internal Control – Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's Management is responsible for these Consolidated Financial Statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control Over Financial Reporting. Our responsibility is to express opinions on the Company's Consolidated Financial Statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the Consolidated Financial Statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the Consolidated Financial Statements included performing procedures to assess the risks of material misstatement of the Consolidated Financial Statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the Consolidated Financial Statements. Our audits also included evaluating the accounting principles used and significant estimates made by Management, as well as evaluating the overall presentation of the Consolidated Financial Statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. 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.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the Consolidated Financial Statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the Consolidated Financial Statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the Consolidated Financial Statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Valuation of an Oil Sands Property Related to the Acquisition of the Remaining 50 Percent Interest in the Sunrise Oil Sands Partnership

As described in Notes 3, 4, and 5 to the Consolidated Financial Statements, on August 31, 2022, the Company acquired the remaining 50 percent interest in the Sunrise Oil Sands Partnership (SOSP), a joint operation in the Oil Sands segment in an acquisition accounted for as a business combination using the acquisition method, which requires that assets acquired and liabilities assumed be measured at fair value on the acquisition date, with any excess of the purchase price over the estimated fair value of the net assets acquired recorded as goodwill. As the Company acquired control of SOSP in stages, Management remeasured the previously held interest in SOSP to fair value of $1.6 billion at the acquisition date and total consideration for the newly acquired 50 percent interest was $1.0 billion. The assets acquired included an oil sands property categorized as Property, Plant and Equipment (PP&E), which was valued at $3.2 billion on a 100 percent basis. Management estimated the fair value of the acquired oil sands property at the acquisition date using an after-tax discounted cash flow model. The fair value assessment required the use of significant estimates and judgments by Management including assumptions related to forward commodity prices, expected production volumes, estimated reserves, future development and operating expenditures and the discount rate. Management's estimate of reserves for the acquired oil sands property were developed by Management's specialists, including internal geology and engineering professionals, and independent qualified reserves evaluators.

The principal considerations for our determination that performing procedures relating to the valuation of the oil sands property related to the acquisition of the remaining 50 percent interest in SOSP is a critical audit matter are (i) the significant judgment by Management, including the use of Management's specialists, as applicable, in developing the fair value of the acquired oil sands property; (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating significant assumptions used in the discounted cash flow model used to value the acquired oil sands property related to forward commodity prices, expected production volumes, estimated reserves, future development and operating expenditures and the discount rate; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the Consolidated Financial Statements. These procedures included testing the effectiveness of controls relating to Management's estimated fair value of the acquired oil sands property. These procedures also included, among others, testing Management's process for determining the fair value of the acquired oil sands property, which included (i) evaluating the appropriateness of the method used by Management in making this estimate; (ii) testing the completeness and accuracy of underlying data used in Management's determination of the fair value and (iii) evaluating the reasonableness of significant assumptions used by Management related to forward commodity prices, expected production volumes, estimated reserves and future development and operating expenditures for the acquired oil sands property. Evaluating the significant assumptions used by Management involved assessing whether the assumptions used were reasonable considering the current and past performance of the acquired oil sands property and consistency with industry pricing forecasts and evidence obtained in other areas of the audit, as applicable. The work of Management's specialists was used in performing the procedures to evaluate the reasonableness of the estimated reserves used to determine the fair value of the acquired oil sands property. As a basis for using this work, the specialists' qualifications were understood, and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the method and assumptions used by the specialists, tests of the data used by the specialists, and an evaluation of the specialists' findings.

Evaluating the significant assumptions used by Management's specialists also involved assessing whether the assumptions used were reasonable considering the current and past performance of the acquired oil sands property and consistency with industry pricing forecasts and evidence obtained in other areas of the audit, as applicable. Professionals with specialized skill and knowledge were used to assist in evaluating the overall reasonableness of the fair value of the acquired oil sands property determined by Management, including the discount rate.

Assessment of Impairment/Impairment Reversal of PP&E for Each of the Cash Generating Units (CGUs) in the U.S. Manufacturing Segment (the U.S. Manufacturing CGUs)

As described in Notes 1, 3, 4, 11 and 20 to the Consolidated Financial Statements, Management assesses its CGUs for indicators of impairment/impairment reversal on a quarterly basis or when facts and circumstances suggest that the carrying amount of a CGU, which is net of accumulated Depreciation, Depletion and Amortization (DD&A) including net impairment losses, may exceed its recoverable amount or that a previously recorded impairment may have reversed. If indicators of impairment or impairment reversal exist, the recoverable amount of the CGU is estimated as the greater of value-in-use and fair value less costs of disposal (FVLCOD). In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined had no impairment loss been recognized on the CGU in prior periods. As of December 31, 2022, the Company had $4.5 billion of PP&E assets net of accumulated DD&A including net impairment losses relating to its U.S. Manufacturing segment. Management identified indicators of impairment for the Superior and Toledo CGUs and performed impairment assessments for each of these CGUs as of December 31, 2022. The carrying amounts of these CGUs were determined to be greater than their recoverable amounts and an aggregate impairment charge of $1.5 billion was recorded as additional DD&A. Management also identified indicators of impairment reversal for the Wood River, Borger and Lima CGUs and performed impairment assessments for each CGU as of December 31, 2022. The recoverable amounts of these CGU's were determined to be greater than their carrying amounts and an aggregate impairment reversal of $1.2 billion was recorded as a reduction to DD&A. Management determined the recoverable amounts of PP&E for the U.S. Manufacturing CGUs based on their FVLCOD using discounted after-tax cash flows models requiring the use of significant assumptions and judgments by Management related to throughput, forward crude oil prices, forward crack spreads, future operating costs, future capital expenditures and discount rates.

The principal considerations for our determination that performing procedures relating to the assessment of impairment/ impairment reversal of PP&E for each of the CGUs in the U.S. Manufacturing segment is a critical audit matter are (i) the significant amount of judgment required by Management when developing the recoverable amounts of the U.S. Manufacturing CGUs; (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures relating to the significant assumptions used in developing these estimates including throughput, forward crude oil prices, forward crack spreads, future capital expenditures, future operating costs and discount rates; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the Consolidated Financial Statements. These procedures included testing the effectiveness of controls relating to Management's determination of the recoverable amounts of the U.S. Manufacturing CGUs. These procedures also included, among others, testing Management's process for determining the recoverable amounts of the U.S. Manufacturing CGUs, which included (i) evaluating the appropriateness of the methods used by Management in making these estimates; (ii) testing the completeness and accuracy of underlying data used in these models; and (iii) assessing the reasonability of the significant assumptions used by Management, including throughput, forward crude oil prices, forward crack spreads, future capital expenditures and future operating costs. Evaluating the assumptions used by Management involved assessing whether the assumptions used were reasonable considering the current and past performance of the Company, consistency with industry pricing forecasts and consistency with evidence obtained in other areas of the audit, as applicable. Professionals with specialized skill and knowledge were used to assist in evaluating the overall reasonableness of the recoverable amounts of the U.S. Manufacturing CGUs, including the discount rates.

Impact of Reserves Estimates on PP&E, Net of the Oil Sands and Offshore Segments

As described in Notes 1, 3, 4, 11 and 20 to the Consolidated Financial Statements, Management assesses its CGUs for indicators of impairment on a quarterly basis or when facts and circumstances suggest that the carrying amount of a CGU, which is net of accumulated DD&A and net impairment losses, may exceed its recoverable amount. Management calculates depletion for Oil Sands PP&E using the unit-of-production method based on estimated proved reserves.

For Offshore PP&E, Management calculates depletion using the unit-of-production method based on estimated proved developed producing reserves or proved plus probable reserves. Costs subject to depletion include estimated future development costs to be incurred in developing proved or proved plus probable reserves. As of December 31, 2022, the Company had $24.7 billion and $2.5 billion in Oil Sands and Offshore PP&E, net, respectively. In aggregate, the Company recognized $3.3 billion of DD&A expense and no impairment related to PP&E in the Oil Sands and Offshore segments in the year ended December 31, 2022. Management identified potential indicators of impairment for the Sunrise CGU as of December 31, 2022 and performed an impairment test.

Management determined the recoverable amount of the Sunrise CGU (the recoverable amount) based on its fair value less costs of disposal using a discounted after-tax cash flow model. The determination of the recoverable amount required the use of significant assumptions and judgments by Management related to forward commodity prices, expected production volumes, estimated reserves, future development and operating expenditures and the discount rate. Management's estimates of reserves used for both the determination of the recoverable amount and the calculation of DD&A expense related to PP&E in the Oil Sands and Offshore segments have been developed by Management's specialists, specifically independent qualified reserves evaluators.

The principal considerations for our determination that performing procedures relating to the impact of reserves estimates on PP&E, net of the Oil Sands and Offshore segments is a critical audit matter are (i) the significant amount of judgment required by Management, including the use of Management's specialists, when developing the estimates of reserves and the recoverable amount; (ii) there was a high degree of auditor judgment, subjectivity, and effort in performing procedures relating to the significant assumptions used in developing these estimates related to forward commodity prices, expected production volumes, estimated reserves, future development and operating expenditures and the discount rate; and (iii) the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the Consolidated Financial Statements. These procedures included testing the effectiveness of controls relating to Management's estimates of reserves, the determination of the recoverable amount and the calculation of DD&A expense related to PP&E in the Oil Sands and Offshore segments. These procedures also included, among others, testing Management's process for determining the recoverable amount and DD&A expense for the Oil Sands and Offshore Segments, which included (i) evaluating the appropriateness of the methods used by Management in making these estimates; (ii) testing the completeness and accuracy of underlying data used in Management's determination of the recoverable amount; (iii) assessing the reasonability of the significant assumptions used by Management, when developing the estimates of reserves and the recoverable amount, related to forward commodity prices, expected production volumes, as well as future development and operating expenditures, and (iv) testing the unit-of-production rates used to calculate DD&A expense. The work of Management's specialists was used in performing the procedures to evaluate the reasonableness of the estimated reserves used in the determination of the recoverable amount and the calculation of DD&A expense related to PP&E in the Oil Sands and Offshore segments. As a basis for using this work, the specialists' qualifications were understood, and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and significant assumptions used by the specialists, tests of data used by the specialists and an evaluation of the specialists' findings. Evaluating the significant assumptions used by Management's specialists related to forward commodity prices, expected production volumes, as well as future development and operating expenditures involved assessing whether the assumptions used were reasonable considering the current and past performance of the Company and consistency with industry pricing forecasts and evidence obtained in other areas of the audit, as applicable. Professionals with specialized skill and knowledge were used to assist in evaluating the reasonableness of the recoverable amount, including the discount rate used.

/s/ PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta, Canada
February 15, 2023
We have served as the Company's auditor since 2008.

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

For the years ended December 31,
($ millions, except per share amounts)

	Notes	**2022**	2021 [(1)]	2020
Revenues	1			
Gross Sales		**71,765**	48,811	13,914
Less: Royalties		**4,868**	2,454	371
		66,897	46,357	13,543
Expenses	1			
Purchased Product		**33,801**	23,326	5,681
Transportation and Blending		**11,530**	8,038	4,728
Operating		**5,569**	4,716	1,955
(Gain) Loss on Risk Management	37	**1,636**	995	308
Depreciation, Depletion and Amortization	11,20,21,23	**4,679**	5,886	3,464
Exploration Expense		**101**	18	91
(Income) Loss From Equity-Accounted Affiliates	22	**(15)**	(57)	—
General and Administrative	6	**865**	849	292
Finance Costs	7	**820**	1,082	536
Interest Income		**(81)**	(23)	(9)
Integration and Transaction Costs	8	**106**	349	29
Foreign Exchange (Gain) Loss, Net	9	**343**	(174)	(181)
Revaluation (Gains)	5	**(549)**	—	—
Re-measurement of Contingent Payments	28	**162**	575	(80)
(Gain) Loss on Divestiture of Assets	10	**(269)**	(229)	(81)
Other (Income) Loss, Net	12	**(532)**	(309)	40
Earnings (Loss) Before Income Tax		**8,731**	1,315	(3,230)
Income Tax Expense (Recovery)	13	**2,281**	728	(851)
Net Earnings (Loss)		**6,450**	587	(2,379)
Net Earnings (Loss) Per Common Share ($)	14			
Basic		**3.29**	0.27	(1.94)
Diluted		**3.20**	0.27	(1.94)

(1) See Note 3X for revisions to prior period results.

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

For the years ended December 31,
($ millions)

	Notes	**2022**	2021	2020
Net Earnings (Loss)		**6,450**	587	(2,379)
Other Comprehensive Income (Loss), Net of Tax	33			
Items That Will not be Reclassified to Profit or Loss:				
Actuarial Gain (Loss) Relating to Pension and Other Post-Employment Benefits	31	**71**	38	(8)
Change in the Fair Value of Equity Instruments at FVOCI [1]		**2**	—	—
Items That may be Reclassified to Profit or Loss:				
Foreign Currency Translation Adjustment		**713**	(129)	(44)
Total Other Comprehensive Income (Loss), Net of Tax		**786**	(91)	(52)
Comprehensive Income (Loss)		**7,236**	496	(2,431)

(1) Fair value through other comprehensive income (loss) ("FVOCI").

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at December 31,
($ millions)

	Notes	2022	2021
Assets			
Current Assets			
Cash and Cash Equivalents	15	**4,524**	2,873
Accounts Receivable and Accrued Revenues	16	**3,473**	3,870
Income Tax Receivable		**121**	22
Inventories	17	**4,312**	3,919
Assets Held for Sale	18	**—**	1,304
Total Current Assets		**12,430**	11,988
Restricted Cash	29	**209**	186
Exploration and Evaluation Assets, Net	1,19	**685**	720
Property, Plant and Equipment, Net	1,20	**36,499**	34,225
Right-of-Use Assets, Net	1,21	**1,845**	2,010
Income Tax Receivable		**25**	66
Investments in Equity-Accounted Affiliates	22	**365**	311
Other Assets	23	**342**	431
Deferred Income Taxes	13	**546**	694
Goodwill	24	**2,923**	3,473
Total Assets		**55,869**	54,104
Liabilities and Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities	25	**6,124**	6,353
Short-Term Borrowings	26	**115**	79
Lease Liabilities	27	**308**	272
Contingent Payments	28	**263**	236
Income Tax Payable		**1,211**	179
Liabilities Related to Assets Held for Sale	18	**—**	186
Total Current Liabilities		**8,021**	7,305
Long-Term Debt	26	**8,691**	12,385
Lease Liabilities	27	**2,528**	2,685
Contingent Payments	28	**156**	—
Decommissioning Liabilities	29	**3,559**	3,906
Other Liabilities	30	**1,042**	929
Deferred Income Taxes	13	**4,283**	3,286
Total Liabilities		**28,280**	30,496
Shareholders' Equity		**27,576**	23,596
Non-Controlling Interest		**13**	12
Total Liabilities and Equity		**55,869**	54,104
Commitments and Contingencies	40		

See accompanying Notes to Consolidated Financial Statements.

[/s/ Keith A. MacPhail]
Keith A. MacPhail
Director
Cenovus Energy Inc.

[/s/ Claude Mongeau]
Claude Mongeau
Director
Cenovus Energy Inc.

February 15, 2023

CONSOLIDATED STATEMENTS OF EQUITY

($ millions)

	Shareholders' Equity							
	Common Shares	Preferred Shares	Warrants	Paid in Surplus	Retained Earnings	AOCI [1]	Total	Non-Controlling Interest
	(Note 32)	(Note 32)	(Note 32)			(Note 33)		
As at December 31, 2019	11,040	—	—	4,377	2,957	827	19,201	—
Net Earnings (Loss)	—	—	—	—	(2,379)	—	(2,379)	—
Other Comprehensive Income (Loss), Net of Tax	—	—	—	—	—	(52)	(52)	—
Total Comprehensive Income (Loss)	—	—	—	—	(2,379)	(52)	(2,431)	—
Stock-Based Compensation Expense	—	—	—	14	—	—	14	—
Base Dividends on Common Shares	—	—	—	—	(77)	—	(77)	—
As at December 31, 2020	11,040	—	—	4,391	501	775	16,707	—
Net Earnings (Loss)	—	—	—	—	587	—	587	—
Other Comprehensive Income (Loss), Net of Tax	—	—	—	—	—	(91)	(91)	—
Total Comprehensive Income (Loss)	—	—	—	—	587	(91)	496	—
Common Shares Issued (Note 5)	6,111	—	—	—	—	—	6,111	—
Common Shares Issued Under Stock Option Plans	7	—	—	(1)	—	—	6	—
Purchase of Common Shares Under NCIBs [2] (Note 32)	(145)	—	—	(120)	—	—	(265)	—
Preferred Shares Issued (Note 5)	—	519	—	—	—	—	519	—
Warrants Issued (Note 5)	—	—	216	—	—	—	216	—
Warrants Exercised	3	—	(1)	—	—	—	2	—
Stock-Based Compensation Expense	—	—	—	14	—	—	14	—
Base Dividends on Common Shares	—	—	—	—	(176)	—	(176)	—
Dividends on Preferred Shares	—	—	—	—	(34)	—	(34)	—
Non-Controlling Interest	—	—	—	—	—	—	—	12
As at December 31, 2021	17,016	519	215	4,284	878	684	23,596	12
Net Earnings (Loss)	**—**	**—**	**—**	**—**	**6,450**	**—**	**6,450**	**—**
Other Comprehensive Income (Loss), Net of Tax	**—**	**—**	**—**	**—**	**—**	**786**	**786**	**—**
Total Comprehensive Income (Loss)	**—**	**—**	**—**	**—**	**6,450**	**786**	**7,236**	**—**
Common Shares Issued Under Stock Option Plans	**170**	**—**	**—**	**(32)**	**—**	**—**	**138**	**—**
Purchase of Common Shares Under NCIBs [2] (Note 32)	**(959)**	**—**	**—**	**(1,571)**	**—**	**—**	**(2,530)**	**—**
Warrants Exercised	**93**	**—**	**(31)**	**—**	**—**	**—**	**62**	**—**
Stock-Based Compensation Expense	**—**	**—**	**—**	**10**	**—**	**—**	**10**	**—**
Base Dividends on Common Shares	**—**	**—**	**—**	**—**	**(682)**	**—**	**(682)**	**—**
Variable Dividends on Common Shares	**—**	**—**	**—**	**—**	**(219)**	**—**	**(219)**	**—**
Dividends on Preferred Shares	**—**	**—**	**—**	**—**	**(35)**	**—**	**(35)**	**—**
Non-Controlling Interest	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**1**
As at December 31, 2022	**16,320**	**519**	**184**	**2,691**	**6,392**	**1,470**	**27,576**	**13**

(1) Accumulated other comprehensive income (loss) ("AOCI").
(2) Normal course issuer bids ("NCIBs").

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31,
($ millions)

	Notes	2022	2021	2020
Operating Activities				
Net Earnings (Loss)		**6,450**	587	(2,379)
Depreciation, Depletion and Amortization	11,20,21,23	**4,679**	5,886	3,464
Inventory Write-Down (Reversal)		**—**	16	555
Realization of Inventory Write-Downs		**—**	(31)	(572)
Deferred Income Tax Expense (Recovery)	13	**642**	452	(838)
Unrealized (Gain) Loss on Risk Management	37	**(126)**	2	56
Unrealized Foreign Exchange (Gain) Loss	9	**365**	(312)	(131)
Realized Foreign Exchange (Gain) Loss on Non-Operating Items		**146**	171	(33)
Revaluation (Gains)	5	**(549)**	—	—
Re-measurement of Contingent Payments, Net of Cash Paid		**(469)**	400	(80)
(Gain) Loss on Divestiture of Assets	10	**(269)**	(229)	(81)
Unwinding of Discount on Decommissioning Liabilities	29	**176**	199	57
(Income) Loss From Equity-Accounted Affiliates	22	**(15)**	(57)	—
Distributions Received From Equity-Accounted Affiliates	22	**65**	137	—
Other		**(117)**	27	99
Settlement of Decommissioning Liabilities		**(150)**	(102)	(42)
Net Change in Non-Cash Working Capital	39	**575**	(1,227)	198
Cash From (Used in) Operating Activities		**11,403**	5,919	273
Investing Activities				
Acquisitions, Net of Cash Acquired	5	**(397)**	735	—
Capital Investment	19,20	**(3,708)**	(2,563)	(859)
Proceeds From Divestitures	10	**1,514**	435	38
Payment on Divestiture of Assets	10	**(50)**	—	—
Net Cash Received on Assumption of Decommissioning Liabilities	5	**—**	75	—
Net Change in Investments and Other		**(211)**	17	(4)
Net Change in Non-Cash Working Capital	39	**538**	359	(38)
Cash From (Used in) Investing Activities		**(2,314)**	(942)	(863)
Net Cash Provided (Used) Before Financing Activities		**9,089**	4,977	(590)
Financing Activities	39			
Net Issuance (Repayment) of Short-Term Borrowings		**34**	(77)	117
Issuance of Long-Term Debt		**—**	1,557	1,326
(Repayment) of Long-Term Debt		**(4,149)**	(2,870)	(112)
Net Issuance (Repayment) of Revolving Long-Term Debt		**—**	(350)	(220)
Principal Repayment of Leases	27	**(302)**	(300)	(197)
Common Shares Issued Under Stock Option Plans		**138**	6	—
Purchase of Common Shares Under NCIBs	32	**(2,530)**	(265)	—
Proceeds From Exercise of Warrants		**62**	2	—
Base Dividends Paid on Common Shares	14	**(682)**	(176)	(77)
Variable Dividends Paid on Common Shares	14	**(219)**	—	—
Dividends Paid on Preferred Shares		**(26)**	(34)	—
Other		**(2)**	—	—
Cash From (Used in) Financing Activities		**(7,676)**	(2,507)	837
Effect of Foreign Exchange on Cash and Cash Equivalents		**238**	25	(55)
Increase (Decrease) in Cash and Cash Equivalents		**1,651**	2,495	192
Cash and Cash Equivalents, Beginning of Year		**2,873**	378	186
Cash and Cash Equivalents, End of Year		**4,524**	2,873	378

See accompanying Notes to Consolidated Financial Statements.

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

Cenovus Energy Inc., including its subsidiaries, (together "Cenovus" or the "Company") is an integrated energy company with crude oil and natural gas production operations in Canada and the Asia Pacific region, and upgrading, refining and marketing operations in Canada and the United States ("U.S."). On January 1, 2021, Cenovus and Husky Energy Inc. ("Husky") closed a transaction to combine the two companies through a plan of arrangement (the "Arrangement") (see Note 5C). The transaction included Husky's upstream assets, extensive transportation, storage and logistics and downstream infrastructure. Comparative figures include Cenovus's results prior to the closing of the Arrangement on January 1, 2021, and do not reflect any historical data from Husky.

Cenovus is incorporated under the Canada Business Corporations Act and its common shares and common share purchase warrants are listed on the Toronto Stock Exchange ("TSX") and New York Stock Exchange. Cenovus's cumulative redeemable preferred shares series 1, 2, 3, 5 and 7 are listed on the TSX. The executive and registered office is located at 4100, 225 6 Avenue S.W., Calgary, Alberta, Canada, T2P 1N2. Information on the Company's basis of preparation for these Consolidated Financial Statements is found in Note 2.

Management has determined the operating segments based on information regularly reviewed for the purposes of decision making, allocating resources and assessing operational performance by Cenovus's chief operating decision maker. The Company's operating segments are aggregated based on their geographic locations, the nature of the businesses or a combination of these factors. The Company evaluates the financial performance of its operating segments primarily based on operating margin.

In September 2022, the Company completed the divestiture of the majority of the retail fuels business. As a result, Management elected to aggregate the remaining commercial fuels business and the historical retail fuels business into the Canadian Manufacturing segment. The marketing operations of the Canadian Manufacturing segment have similar products and services, customer types, distribution methods and operate in the same regulatory environment as the commercial fuels business. The commercial fuels business includes cardlock, bulk plant and travel centre locations across Canada. Comparative periods have been re-presented to reflect this change (see Note 3X).

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 natural gas liquids ("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 Refinery and Superior Refinery, the jointly-owned Wood River and Borger refineries (jointly owned with operator Phillips 66) and the jointly-owned Toledo Refinery (jointly owned with operator BP Products North America Inc. ("BP")). Cenovus also markets some of its own and third-party volumes of refined petroleum products including gasoline, diesel and jet fuel.

Corporate and Eliminations

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

A) Results of Operations – Segment and Operational Information

	Upstream											
For the years ended	Oil Sands			Conventional			Offshore			Total		
December 31,	**2022**	2021 (1)	2020	**2022**	2021	2020	**2022**	2021	2020	**2022**	2021 (1)	2020
Revenues												
Gross Sales	**34,775**	22,827	8,804	**4,332**	3,235	904	**2,020**	1,782	—	**41,127**	27,844	9,708
Less: Royalties	**4,493**	2,196	331	**298**	150	40	**77**	108	—	**4,868**	2,454	371
	30,282	20,631	8,473	**4,034**	3,085	864	**1,943**	1,674	—	**36,259**	25,390	9,337
Expenses												
Purchased Product	**4,810**	2,404	1,262	**2,023**	1,655	268	**—**	—	—	**6,833**	4,059	1,530
Transportation and Blending	**12,036**	8,625	4,683	**143**	74	81	**15**	15	—	**12,194**	8,714	4,764
Operating	**2,930**	2,451	1,156	**541**	551	320	**318**	239	—	**3,789**	3,241	1,476
Realized (Gain) Loss on Risk Management	**1,527**	786	268	**92**	2	—	**—**	—	—	**1,619**	788	268
Operating Margin	**8,979**	6,365	1,104	**1,235**	803	195	**1,610**	1,420	—	**11,824**	8,588	1,299
Unrealized (Gain) Loss on Risk Management	**(68)**	18	57	**13**	1	—	**—**	—	—	**(55)**	19	57
Depreciation, Depletion and Amortization	**2,763**	2,666	1,687	**370**	3	880	**585**	492	—	**3,718**	3,161	2,567
Exploration Expense	**9**	16	9	**1**	(3)	82	**91**	5	—	**101**	18	91
(Income) Loss From Equity-Accounted Affiliates	**8**	(5)	—	**—**	—	—	**(23)**	(47)	—	**(15)**	(52)	—
Segment Income (Loss)	**6,267**	3,670	(649)	**851**	802	(767)	**957**	970	—	**8,075**	5,442	(1,416)

(1) Prior period results have been adjusted to more appropriately reflect the cost of blending (see Note 3X).

	Downstream								
	Canadian Manufacturing			**U.S. Manufacturing**			**Total**		
For the years ended December 31,	**2022**	2021 [1]	2020	**2022**	2021	2020	**2022**	2021 [1]	2020
Revenues									
Gross Sales	**7,792**	6,215	82	**30,310**	20,043	4,733	**38,102**	26,258	4,815
Less: Royalties	**—**	—	—	**—**	—	—	**—**	—	—
	7,792	6,215	82	**30,310**	20,043	4,733	**38,102**	26,258	4,815
Expenses									
Purchased Product	**6,389**	5,156	—	**26,112**	17,955	4,429	**32,501**	23,111	4,429
Transportation and Blending	**—**	—	—	**—**	—	—	**—**	—	—
Operating	**704**	486	37	**2,346**	1,772	748	**3,050**	2,258	785
Realized (Gain) Loss on Risk Management	**—**	—	—	**112**	104	(21)	**112**	104	(21)
Operating Margin	**699**	573	45	**1,740**	212	(423)	**2,439**	785	(378)
Unrealized (Gain) Loss on Risk Management	**—**	—	—	**18**	1	(1)	**18**	1	(1)
Depreciation, Depletion and Amortization	**208**	226	8	**640**	2,381	728	**848**	2,607	736
Exploration Expense	**—**	—	—	**—**	—	—	**—**	—	—
(Income) Loss From Equity-Accounted Affiliates	**—**	—	—	**—**	—		**—**	—	—
Segment Income (Loss)	**491**	347	37	**1,082**	(2,170)	(1,150)	**1,573**	(1,823)	(1,113)

(1) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment (see Note 3X).

	Corporate and Eliminations			Consolidated		
For the years ended December 31,	**2022**	2021 (1) (2)	2020	**2022**	2021 (1) (2)	2020
Revenues						
Gross Sales	**(7,464)**	(5,291)	(609)	**71,765**	48,811	13,914
Less: Royalties	**—**	—	—	**4,868**	2,454	371
	(7,464)	(5,291)	(609)	**66,897**	46,357	13,543
Expenses						
Purchased Product	**(5,533)**	(3,844)	(278)	**33,801**	23,326	5,681
Transportation and Blending	**(664)**	(676)	(36)	**11,530**	8,038	4,728
Operating	**(1,270)**	(783)	(306)	**5,569**	4,716	1,955
Realized (Gain) Loss on Risk Management	**31**	101	5	**1,762**	993	252
Unrealized (Gain) Loss on Risk Management	**(89)**	(18)	—	**(126)**	2	56
Depreciation, Depletion and Amortization	**113**	118	161	**4,679**	5,886	3,464
Exploration Expense	**—**	—	—	**101**	18	91
(Income) Loss From Equity-Accounted Affiliates	**—**	(5)	—	**(15)**	(57)	—
Segment Income (Loss)	**(52)**	(184)	(155)	**9,596**	3,435	(2,684)
General and Administrative	**865**	849	292	**865**	849	292
Finance Costs	**820**	1,082	536	**820**	1,082	536
Interest Income	**(81)**	(23)	(9)	**(81)**	(23)	(9)
Integration and Transaction Costs	**106**	349	29	**106**	349	29
Foreign Exchange (Gain) Loss, Net	**343**	(174)	(181)	**343**	(174)	(181)
Revaluation (Gains)	**(549)**	—	—	**(549)**	—	—
Re-measurement of Contingent Payment	**162**	575	(80)	**162**	575	(80)
(Gain) Loss on Divestiture of Assets	**(269)**	(229)	(81)	**(269)**	(229)	(81)
Other (Income) Loss, Net	**(532)**	(309)	40	**(532)**	(309)	40
	865	2,120	546	**865**	2,120	546
Earnings (Loss) Before Income Tax				**8,731**	1,315	(3,230)
Income Tax Expense (Recovery)				**2,281**	728	(851)
Net Earnings (Loss)				**6,450**	587	(2,379)

(1) Prior period results have been adjusted to more appropriately reflect the cost of blending (see Note 3X).
(2) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment (see Note 3X).

B) Revenues by Product

For the years ended December 31,	2022	2021	2020
Upstream			
Crude Oil [1]	**29,834**	19,877	8,017
NGLs [1]	**2,346**	1,983	727
Natural Gas	**3,690**	3,032	535
Other	**389**	498	58
Downstream			
Canadian Manufacturing			
Synthetic Crude Oil	**2,360**	1,951	—
Asphalt	**620**	477	—
Other Products and Services [2]	**4,812**	3,787	82
U.S. Manufacturing			
Gasoline	**14,116**	10,111	2,352
Diesel and Distillate	**11,453**	6,429	1,569
Other Products	**4,741**	3,503	812
Corporate and Eliminations [2]	**(7,464)**	(5,291)	(609)
Consolidated	**66,897**	46,357	13,543

(1) Prior period results have been re-presented. Third-party condensate sales previously included in crude oil have been aggregated with NGLs.
(2) Prior period results have been re-presented. The Retail segment has been aggregated with the Canadian Manufacturing segment (see Note 3X).

C) Geographical Information

	Revenues [1]		
For the years ended December 31,	2022	2021	2020
Canada	**33,222**	23,768	8,715
United States	**32,313**	21,326	4,828
China	**1,362**	1,263	—
Consolidated	**66,897**	46,357	13,543

(1) Revenues by country are classified based on where the operations are located.

	Non-Current Assets [1]	
As at December 31,	2022	2021 [2]
Canada	**35,194**	33,981
United States	**4,824**	4,093
China	**2,064**	2,583
Indonesia	**365**	311
Consolidated	**42,447**	40,968

(1) Includes exploration and evaluation ("E&E") assets, property, plant and equipment ("PP&E"), right-of-use ("ROU") assets, income tax receivable, investments in equity-accounted affiliates, precious metals, intangible assets and goodwill.
(2) Canada excludes assets held for sale of $1.3 billion that were divested in 2022.

Major Customers

In connection with the marketing and sale of Cenovus's own and purchased crude oil, NGLs, natural gas and refined products for the year ended December 31, 2022, Cenovus had two customers (2021 – two; 2020 – three) that individually accounted for more than 10 percent of its consolidated gross sales. Sales to these customers, recognized as major international energy companies with investment grade credit ratings, were approximately $16.1 billion and $9.1 billion, respectively (2021 – $8.5 billion and $6.8 billion; 2020 – $4.3 billion, $1.8 billion and $1.5 billion, respectively), and are reported across all of the Company's operating segments.

D) Assets by Segment

	E&E Assets		PP&E		ROU Assets	
As at December 31,	**2022**	2021	**2022**	2021	**2022**	2021
Oil Sands	**674**	653	**24,657**	22,535	**638**	754
Conventional	**6**	6	**2,020**	2,174	**2**	2
Offshore	**5**	61	**2,549**	2,822	**152**	160
Canadian Manufacturing (1)	**—**	—	**2,466**	2,558	**252**	388
U.S. Manufacturing	**—**	—	**4,482**	3,745	**329**	252
Corporate and Eliminations	**—**	—	**325**	391	**472**	454
Consolidated	**685**	720	**36,499**	34,225	**1,845**	2,010

	Goodwill		Total Assets	
As at December 31,	**2022**	2021	**2022**	2021 (2)
Oil Sands	**2,923**	3,473	**32,248**	31,070
Conventional	**—**	—	**2,410**	3,026
Offshore	**—**	—	**3,339**	3,597
Canadian Manufacturing (1)	**—**	—	**3,172**	3,884
U.S. Manufacturing (3)	**—**	—	**8,324**	7,509
Corporate and Eliminations (3)	**—**	—	**6,376**	5,018
Consolidated	**2,923**	3,473	**55,869**	54,104

(1) *Prior period results have been re-presented. PP&E, ROU assets and total assets from the remaining commercial fuels business and the historic retail fuels business have been aggregated with the Canadian Manufacturing segment.*
(2) *Total assets include assets held for sale $1.3 billion that were divested in 2022.*
(3) *Prior period results were re-presented to move income tax receivable and deferred income tax assets from the U.S. Manufacturing segment to the Corporate and Eliminations segment.*

E) Capital Expenditures [1]

For the years ended December 31,	2022	2021	2020
Capital Investment			
Oil Sands	**1,792**	1,019	427
Conventional	**344**	222	78
Offshore			
Asia Pacific	**8**	21	—
Atlantic	**302**	154	—
Total Upstream	**2,446**	1,416	505
Canadian Manufacturing [2]	**117**	68	33
U.S. Manufacturing	**1,059**	995	243
Total Downstream	**1,176**	1,063	276
Corporate and Eliminations	**86**	84	60
	3,708	2,563	841
Acquisitions (Note 5)			
Oil Sands [3]	**1,609**	5,005	6
Conventional	**12**	551	12
Offshore [4]	**—**	3,129	—
Canadian Manufacturing [2]	**—**	2,973	—
U.S. Manufacturing	**—**	1,618	—
Corporate and Eliminations	**—**	156	—
	1,621	13,432	18
Total Capital Expenditures	**5,329**	15,995	859

(1) Includes expenditures on PP&E, E&E assets and capitalized interest.

(2) Prior period results have been re-presented. The Retail segment has been aggregated with the Canadian Manufacturing segment (see Note 3X).

(3) Cenovus was deemed to have disposed of its pre-existing interest in Sunrise Oil Sands Partnership ("SOSP") and reacquired it at fair value as required by International Financial Reporting Standard 3, "Business Combinations" ("IFRS 3"). The acquisition capital above does not include the fair value of the pre-existing interest in SOSP of $1.6 billion.

(4) Excludes capital expenditures related to the HCML joint venture, which are accounted for using the equity method.

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

In these Consolidated Financial Statements, unless otherwise indicated, all dollars are expressed in Canadian dollars. All references to C$ or $ are to Canadian dollars and references to US$ are to U.S. dollars.

These Consolidated Financial Statements have been prepared in accordance with IFRS as issued by the International Accounting Standards Board and interpretations of the International Financial Reporting Interpretations Committee.

These Consolidated Financial Statements have been prepared on a historical cost basis, except as detailed in the Company's accounting policies disclosed in Note 3.

These Consolidated Financial Statements were approved by the Board of Directors effective February 15, 2023.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of Cenovus and its subsidiaries. Subsidiaries are entities over which the Company has control. Subsidiaries are consolidated from the date of acquisition of control and continue to be consolidated until the date that there is a loss of control. All intercompany transactions, balances, and unrealized gains and losses from intercompany transactions are eliminated on consolidation.

Interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Joint operations arise when the Company has rights to the assets and obligations for the liabilities of the arrangement. The Company's accounts reflect its share of the assets, liabilities, revenues and expenses from the Company's activities that are conducted through joint operations with third parties. A portion of the Company's activities relate to joint ventures, which are accounted for using the equity method of accounting.

An associate is an entity for which the Company has significant influence over but does not control or jointly control the affiliate. Investments in associates are accounted for using the equity method of accounting and are recognized at cost and adjusted thereafter to recognize the Company's share of the affiliate's profit or loss and other comprehensive income ("OCI").

B) Foreign Currency Translation

Functional and Presentation Currency

The Company's functional and presentation currency is Canadian dollars. The accounts of the Company's foreign operations that have a functional currency different from the Company's presentation currency are translated into the Company's presentation currency at period-end exchange rates for assets and liabilities, and using average rates over the period for revenues and expenses. Translation gains and losses relating to the foreign operations are recognized in OCI as cumulative translation adjustments.

When the Company disposes of an entire interest in a foreign operation or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in OCI related to the foreign operation are recognized in net earnings. When the Company disposes of part of an interest in a foreign operation that continues to be a subsidiary, a proportionate amount of gains and losses accumulated in OCI is allocated between controlling and non-controlling interests.

Transactions and Balances

Transactions in foreign currencies are translated to the respective functional currencies at exchange rates in effect at the dates of the transactions. Monetary assets and liabilities of Cenovus that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the reporting date. Any gains or losses are recorded in the Consolidated Statements of Earnings (Loss).

C) Revenue Recognition

Revenue is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. Cenovus recognizes revenue when it transfers control of the product or service to a customer, which is generally when title passes from the Company to its customer.

Purchases and sales of products that are entered into in contemplation of each other with the same counterparty are recorded on a net basis. Revenues associated with services provided as agent are recorded as the services are provided.

Cenovus recognizes revenue from the following major products and services:

- Sale of crude oil, NGLs and natural gas.
- Sale of petroleum and refined products.
- Crude oil and natural gas processing services.
- Pipeline transportation, the blending of crude oil and the storage of crude oil, diluent and natural gas.
- Fee-for-service hydrocarbon transloading services.
- Construction services.

The Company satisfies its performance obligations in contracts with customers upon the delivery of crude oil, NGLs, natural gas, and petroleum and refined products, which is generally at a point in time. Performance obligations for crude oil and natural gas processing revenue, transportation services and transloading services are satisfied over time as the service is provided. Cenovus sells its production of crude oil, NGLs, natural gas, and petroleum and refined products generally pursuant to variable price contracts. The transaction price for variable price contracts is based on the commodity price, adjusted for quality, location and other factors. Revenue associated with natural gas processing, transportation services and transloading services are generally based on fixed price contracts.

Construction revenue is recognized for general contractor services that the Company provides to HMLP and includes fixed price and cost-plus contracts. Revenue from fixed price construction contracts is recognized as performance obligations are met and revenue from cost-plus contracts are recognized as services are performed.

The Company has take-or-pay contracts where Cenovus has long-term supply commitments in return for purchasers to pay for minimum quantities, whether or not the customer takes the delivery. If a purchaser has a right to defer delivery to a later date, the performance obligation has not been satisfied and revenue is deferred and recognized only when the product is delivered or the deferral provision can no longer be extended.

Cenovus's revenue transactions do not contain significant financing components and payments are typically due within 30 days of revenue recognition. The Company does not adjust transaction prices for the effects of a significant financing component when the period between the transfer of the promised goods or services to the customer and payment by the customer is less than one year. The Company does not disclose or quantify information about remaining performance obligations that have an original expected duration of one year or less and it does not have any long-term contracts with the exception of certain construction contracts with HMLP and take-or-pay contracts with unfulfilled performance obligations.

D) Purchased Product

The cost of refining feedstock, crude oil and diluent purchased for optimization activities, and costs associated with transporting refined products to market are recorded as purchased product.

E) Transportation and Blending

The costs associated with the transportation of crude oil, NGLs and natural gas for upstream operations, including the cost of diluent used in blending, are recognized when the product is sold.

F) Exploration Expense

Costs incurred prior to obtaining the legal right to explore (pre-exploration costs) are expensed in the period in which they are incurred as exploration expense.

Certain costs incurred after the legal right to explore is obtained are initially capitalized. If it is determined that the field/project/area is not technically feasible and commercially viable or if the Company decides not to continue the exploration and evaluation activity, the unrecoverable accumulated costs are expensed as exploration expense.

G) Employee Benefit Plans

The Company provides employees with a pension plan that includes either a defined contribution or defined benefit component.

Other post-employment benefit ("OPEB") plans are also provided to qualifying employees. In some cases, the benefits are provided through medical care plans to which the Company, the employees, the retirees and covered family members contribute. In some plans, benefits are not funded before retirement.

Pension expense for the defined contribution pension is recorded as the benefits are earned.

The cost of the defined benefit pension and OPEB plans are actuarially determined using the projected unit credit method. The amount recognized in other liabilities on the Consolidated Balance Sheets for the defined benefit pension and OPEB plans is the present value of the defined benefit obligation less the fair value of plan assets. Any surplus resulting from this calculation is limited to the present value of any economic benefits available in the form of refunds from the plans or reductions in future contributions to the plans.

Changes in the defined benefit obligation from service costs, net interest and re-measurements are recognized as follows:

- Service costs, including current service costs, past service costs, gains and losses on curtailments, and settlements, are recorded with pension benefit costs.
- Net interest is calculated by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period to the net defined benefit asset or liability measured. Interest expense and interest income on net post-employment benefit liabilities and assets are recorded with pension benefit costs in operating, and general and administrative expenses, as well as PP&E and E&E assets.
- Re-measurements, composed of actuarial gains and losses, the effect of changes to the asset ceiling (excluding interest) and the return on plan assets (excluding interest income), are charged or credited to equity in OCI in the period in which they arise. Re-measurements are not reclassified to net earnings in subsequent periods.

Pension benefit costs are recorded in operating, and general and administrative expenses, as well as PP&E and E&E assets, corresponding to where the associated salaries of the employees rendering the service are recorded.

H) Government Grants

Government grants are recognized when there is reasonable assurance that the grant will be received and all conditions associated with the grant are met. If a grant is received, but reasonable assurance and compliance with conditions is not achieved, the grant is recognized as a deferred liability until the conditions are fulfilled. Grants related to assets are recorded as a reduction to the asset's carrying value and are depreciated over the useful life of the asset. Claims under government grant programs related to income are recorded as other income in the period in which eligible expenses were incurred or when the services have been performed.

I) Income Taxes

Income taxes comprise current and deferred taxes. Income taxes are provided for on a non-discounted basis at amounts expected to be paid using the tax rates and laws that have been enacted or substantively enacted at the Consolidated Balance Sheet date.

Cenovus follows the liability method of accounting for income taxes, where deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates expected to apply when the assets are realized or liabilities are settled. Deferred income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs, except when it relates to items charged or credited directly to equity or OCI, in which case the deferred income tax is also recorded in equity or OCI, respectively.

Deferred income tax is recognized on temporary differences arising from investments in subsidiaries except in the case where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not reverse in the foreseeable future or when distributions can be made without incurring income taxes.

Deferred income tax assets are recognized only to the extent that it is probable that future taxable profit will be available against which the temporary differences can be utilized. Deferred income tax assets and liabilities are only offset where they arise within the same entity and tax jurisdiction. Deferred income tax assets and liabilities are presented as non-current.

J) Related Party Transactions

The Company enters into transactions and agreements in the normal course of business with certain related parties, joint arrangements and associates. Proceeds from the disposition of assets to related parties are recognized at fair value. Independent opinions of fair value may be obtained to confirm the estimated fair value of proceeds.

K) Net Earnings per Share Amounts

Basic net earnings per share is computed by dividing net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share is calculated giving effect to the potential dilution that would occur if stock options or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options and other dilutive instruments are used to purchase common shares at the average market price. For those contracts that may be settled in cash or in shares at the holder's option, the more dilutive of cash settlement and share settlement is used in calculating diluted earnings per share.

L) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments with a maturity of three months or less.

Cash and cash equivalents that are not available for use are classified as restricted cash. When restricted cash is not expected to be used within twelve months, it is classified as a non-current asset.

M) Inventories

Product inventories are valued at the lower of cost and net realizable value on a first-in, first-out or weighted average cost basis. The cost of inventory includes all costs incurred in the normal course of business to bring each product to its present location and condition. Net realizable value is the estimated selling price in the ordinary course of business less any expected selling costs. If the carrying amount exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if circumstances which caused it no longer exist and the inventory is still on hand.

N) Exploration and Evaluation Assets

Certain costs incurred after the legal right to explore an area has been obtained, and before technical feasibility and commercial viability of the field/project/area have been established, are capitalized as E&E assets. E&E assets are carried forward until technical feasibility and commercial viability of the field/project/area is established or the assets are determined to be impaired or the future economic value has decreased. E&E assets are subject to regular technical, commercial and Management review to confirm the continued intent to develop the resources.

Assets classified as E&E may have sales of crude oil, NGLs or natural gas prior to the reclassification to PP&E. These operating results are recognized in the Consolidated Statements of Earnings (Loss). A depletion charge, recorded as depreciation, depletion and amortization ("DD&A"), is recognized on this production using a unit-of-production method based on estimated proved reserves determined using forward prices and costs and considering any estimated future costs to be incurred in developing the proved reserves. Natural gas reserves are converted on an energy equivalent basis.

Non-producing assets classified as E&E are not depleted.

Once technical feasibility and commercial viability have been established, the carrying value of the E&E asset is tested for impairment. The carrying value, net of any impairment loss, is then reclassified as PP&E.

Any gains or losses from the divestiture of E&E assets are recognized in net earnings.

O) Property, Plant and Equipment

General

PP&E is stated at cost less accumulated DD&A, and net of any impairment losses. Expenditures related to renewals or enhancements that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred. Land is not depreciated.

Any gains or losses from the divestiture of PP&E are recognized in net earnings.

Crude Oil and Natural Gas Properties

Development and production assets are capitalized on an area-by-area basis and include all costs associated with the development and production of crude oil and natural gas properties and related infrastructure facilities, as well as any E&E expenditures incurred in finding reserves of crude oil, NGLs or natural gas transferred from E&E assets. Capitalized costs include directly attributable internal costs, decommissioning liabilities and, for qualifying assets, borrowing costs directly associated with the acquisition of, the exploration for, and the development of crude oil and natural gas reserves.

For onshore assets, which includes assets from the Oil Sands and Conventional segments, costs accumulated within each area are depleted using the unit-of-production method based on estimated proved reserves determined using forward prices and costs. Offshore assets are depleted using the unit-of-production method based on estimated proved developed producing reserves or proved plus probable reserves determined using forward prices and costs. For the purpose of these calculations, natural gas is converted to crude oil on an energy equivalent basis. The unit-of-production method based on proved reserves or proved plus probable reserves takes into account any expenditures incurred to date together with future development costs to be incurred in developing those reserves.

Exchanges of development and production assets are measured at fair value unless the transaction lacks commercial substance or the fair value of either the asset received, or the asset given up, cannot be reliably measured. When fair value is not used, the carrying amount of the asset given up is used as the cost of the asset acquired.

Included in oil and gas properties are information technology assets used to support the upstream business and are depreciated on a straight-line basis over their useful lives of three years. Gross overriding royalty interests ("GORRs") in certain crude oil and natural gas properties are depleted using a unit-of-production method.

Manufacturing Assets

The initial costs of refining and upgrading PP&E are capitalized when incurred. Costs include the cost of constructing or otherwise acquiring the equipment or facilities, the cost of installing the asset and making it ready for its intended use, the associated decommissioning costs and, for qualifying assets, borrowing costs.

Refining and upgrading assets are depreciated on a straight-line basis over the estimated service life of each component of the refinery. The major components are depreciated as follows:

- Land improvements and buildings: 15 to 40 years.
- Office improvements and buildings: 3 to 15 years.
- Refining equipment: 10 to 60 years.

The residual value, the method of amortization and the useful life of each component are reviewed annually and adjusted on a prospective basis, if appropriate.

Processing, Transportation and Storage Assets, Commercial Fuels Business and Other

Depreciation for substantially all other PP&E is calculated on a straight-line basis based on the estimated useful lives of assets, which range from three to 60 years. The useful lives are estimated based upon the period the asset is expected to be available for use by the Company.

The residual value, the method of amortization and the useful life of the assets are reviewed annually and adjusted on a prospective basis, if appropriate.

P) Impairment and Impairment Reversals of Non-Financial Assets

PP&E, E&E assets and ROU assets are reviewed separately for indicators of impairment on a quarterly basis or when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. Goodwill is tested for impairment at least annually.

If indicators of impairment exist, the recoverable amount of the asset or cash-generating unit ("CGU") is estimated as the greater of value-in-use ("VIU") and fair value less costs of disposal ("FVLCOD"). VIU is estimated as the present value of the future cash flows expected to arise from the continuing use of a CGU or an asset. FVLCOD is the amount that would be realized from the disposition of an asset or CGU in an arm's length transaction between knowledgeable and willing parties. For Cenovus's upstream assets, FVLCOD is estimated based on the discounted after-tax cash flows of reserves and resources using forward prices and costs, consistent with Cenovus's independent qualified reserves evaluators ("IQREs"), costs to develop and the discount rate, and may consider an evaluation of comparable asset transactions.

E&E assets are allocated to a related CGU containing development and production assets for the purposes of testing for impairment. ROU assets may be tested as part of a CGU, as a separate CGU or as an individual asset. Goodwill is allocated to the CGUs to which it contributes to the future cash flows.

If the recoverable amount of the CGU is less than the carrying amount, an impairment loss is recognized. An impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amounts of the other assets in the CGU. Goodwill impairments are not reversed.

Impairment losses on PP&E and ROU assets are recognized in the Consolidated Statements of Earnings (Loss) as additional DD&A and E&E asset impairments or write-downs are recognized as exploration expense.

Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net earnings.

Q) Leases

The Company assesses whether a contract is a lease based on whether the contract conveys the right to control the use of an underlying asset for a period of time in exchange for consideration. The Company allocates the consideration in the contract to each lease component on the basis of their relative stand-alone prices. However, for the leases of storage tanks, the Company has elected not to separate non-lease components.

As Lessee

Leases are recognized as a ROU asset and a corresponding lease liability at the date on which the leased asset is available for use by the Company. Assets and liabilities arising from a lease are initially measured on a present value basis. Lease liabilities include the net present value of fixed payments, costs to be incurred by the lessee in dismantling, removing and restoring the underlying asset, variable lease payments that are based on an index or a rate, amounts expected to be paid by the lessee under residual value guarantees, the exercise price of purchase options if the lessee is reasonably certain to exercise that option, and payments of penalties for terminating the lease, less any lease incentives receivable. These payments are discounted using the Company's incremental borrowing rate when the rate implicit in the lease is not readily available. The Company uses a single discount rate for a portfolio of leases with reasonably similar characteristics.

Lease payments are allocated between the liability and finance costs. The finance cost is charged to net earnings over the lease term.

The lease liability is measured at amortized cost using the effective interest method. It is re-measured when there is a change in the future lease payments arising from a change in an index or rate, if there is a change in the amount expected to be payable under a residual value guarantee or if there is a change in the assessment of whether the Company will exercise a purchase, extension or termination option that is within the control of the Company.

When the lease liability is re-measured, a corresponding adjustment is made to the carrying amount of the ROU asset or is recorded in the Consolidated Statements of Earnings (Loss) if the carrying amount of the ROU asset has been reduced to zero.

The ROU asset is initially measured at cost, which comprises the initial amount of the lease liability any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or site on which it is located less any lease payments made at or before the commencement date.

The ROU asset is depreciated on a straight-line basis, over the shorter of the estimated useful life of the asset or lease term, or using the unit-of-production method. The ROU asset may be adjusted for certain re-measurements of the lease liability and impairment losses.

Leases that have a term of less than twelve months or leases for which the underlying asset is of low value are recognized as an expense in the Consolidated Statements of Earnings (Loss) on a systematic basis over the lease term in either operating, transportation or general and administrative expense.

A lease modification will be accounted for as a separate lease if the modification increases the scope of the lease and if the consideration for the lease increases by an amount commensurate with the stand-alone price for the increase in scope. For a modification that is not a separate lease or where the increase in consideration is not commensurate, at the effective date of the lease modification, the Company will re-measure the lease liability using the Company's incremental borrowing rate, when the rate implicit to the lease is not readily available, with a corresponding adjustment to the ROU asset. A modification that decreases the scope of the lease will be accounted for by decreasing the carrying amount of the ROU asset, and recognizing a gain or loss in net earnings that reflects the proportionate decrease in scope.

As Lessor

As a lessor, the Company assesses at inception whether a lease is a finance or operating lease. Leases where the Company transfers substantially all of the risk and rewards incidental to ownership of the underlying asset are classified as financing leases. Under a finance lease, the Company recognizes a receivable at an amount equal to the net investment in the lease which is the present value of the aggregate of lease payments receivable by the lessor. If substantially all the risks and rewards of ownership of an asset are not transferred the lease is classified as an operating lease. The Company recognizes lease payments received under operating leases as income on a straight-line basis over the lease term as other income.

When the Company is an intermediate lessor, it accounts for its interest in the head lease and the sublease separately. It assesses the lease classification of a sublease with reference to the ROU asset from the head lease not with reference to the underlying assets. If the head lease is a short-term lease to which the Company applies the exemption for lease accounting, the sublease is classified as an operating lease.

R) Intangible Assets

Intangible assets acquired separately are initially measured at cost. Following initial recognition, intangible assets are recognized at cost less any accumulated amortization and accumulated impairment losses. Intangible assets with finite lives are amortized over the useful life and assessed for impairment whenever there is an indication that the intangible asset may be impaired. The amortization expense on intangible assets is recognized in the Consolidated Statements of Earnings (Loss) in the expense category consistent with the function of the intangible asset. Impairment losses are recognized in the Consolidated Statements of Earnings(Loss) as DD&A.

S) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method of accounting in which the identifiable assets acquired, liabilities assumed and non-controlling interest, if any, are recognized and measured at their fair value at the date of acquisition, with the exception of income taxes, stock-based compensation, lease liabilities and ROU assets. Any excess of the purchase price plus any non-controlling interest over the value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price over the value of the net assets acquired is credited to net earnings. Acquisition costs are expensed as incurred.

At acquisition, goodwill is allocated to each of the CGUs to which it relates. Subsequent measurement of goodwill is at cost less any accumulated impairment losses.

Contingent consideration transferred in a business combination is measured at fair value on the date of acquisition and classified as a financial liability or equity in accordance with the terms of the agreement. Contingent consideration classified as a liability is re-measured at fair value at each reporting date, with changes in fair value recognized in net earnings. Payments are classified as cash used in investing activities until the cumulative payments exceed the acquisition date fair value of the liability. Cumulative payments in excess of the acquisition date fair value are classified as cash used in operating activities. Contingent consideration classified as equity are not re-measured and settlements are accounted for within equity.

When a business combination is achieved in stages, the Company re-measures its pre-existing interest at the acquisition date fair value and recognizes the resulting gain or loss, if any, in net earnings.

T) Provisions

A provision is recognized if, as a result of a past event, the Company has a present obligation, legal or constructive, that can be estimated reliably, and it is more likely than not that an outflow of economic benefits will be required to settle the obligation. Where applicable, provisions are determined by discounting the expected future cash flows at a pre-tax credit-adjusted rate that reflects the current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as a finance cost in the Consolidated Statements of Earnings (Loss).

Decommissioning Liabilities

Decommissioning liabilities include those legal or constructive obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, upstream processing facilities, surface and subsea plant and equipment, refining facilities and the crude-by-rail terminal. The amount recognized is the present value of estimated future expenditures required to settle the obligation using a credit-adjusted risk-free rate. A corresponding asset equal to the initial estimate of the liability is capitalized as part of the cost of the related long-lived asset. Changes in the estimated liability resulting from revisions to expected timing or future decommissioning costs are recognized as a change in the decommissioning liability and the related long-lived asset. The amount capitalized in PP&E is depreciated over the useful life of the related asset.

Actual expenditures incurred are charged against the accumulated liability.

Onerous Contract Provisions

Onerous contract provisions are recognized when the unavoidable costs of meeting the obligation exceed the economic benefit derived from the contract. The provision for onerous contracts is measured at the present value of estimated future cash flows underlying the obligations less any estimated recoveries, discounted at the credit-adjusted risk-free rate. Changes in the underlying assumptions are recognized in the Consolidated Statements of Earnings (Loss).

Renewable Fuel Obligations

The Company's U.S. refining operations incur a renewable volume obligation ("RVO"), which the Company settles annually using renewable identification numbers ("RINs"). After considering RINs on hand, the RVO is measured as the expected market price of the additional RINs required to settle the compliance obligation. RINs purchased with biofuel are measured using the average market price in the month purchased. RINs purchased on a secondary market are measured at cost. A net RIN position is presented in other assets and a net RVO position is included in other liabilities.

U) Share Capital and Warrants

Common shares and preferred shares are classified as equity. Preferred shares are cancellable and redeemable only at the Company's option. Dividends on common shares consist of base dividends and variable dividends. Variable dividends are reviewed quarterly and paid if certain performance measurements are met at the end of the applicable period. Dividends on common shares and preferred shares are discretionary and payable only if declared by Cenovus's Board of Directors. If a dividend on any preferred share is not paid in full on any dividend payment date, then a dividend restriction on the common shares shall apply. The preferred share dividends are cumulative.

Transaction costs directly attributable to the issue of common shares and preferred shares are recognized as a deduction from equity, net of any income taxes. Dividends on common shares and preferred shares are recognized within equity. When purchased, common shares are reduced by the average carrying value with the excess of the purchase price recognized as a reduction in Cenovus's paid in surplus. Common shares are cancelled subsequent to being purchased.

Warrants issued in the Arrangement are financial instruments classified as equity and were measured at fair value upon issuance. On exercise, the cash consideration received by the Company and the associated carrying value of the warrants are recorded as share capital.

V) Stock-Based Compensation

Cenovus has a number of stock-based compensation plans which include stock options with associated net settlement rights ("NSRs"), Cenovus replacement stock options, performance share units ("PSUs"), restricted share units ("RSUs") and deferred share units ("DSUs"). Stock-based compensation costs are recorded in general and administrative expenses, or recorded to PP&E or E&E assets when directly related to exploration or development activities.

Stock Options With Associated Net Settlement Rights

NSRs are accounted for as equity instruments, which are measured at fair value on the grant date using the Black-Scholes-Merton valuation model and are not revalued at each reporting date. The fair value is recognized as stock-based compensation over the vesting period, with a corresponding increase recorded as paid in surplus in shareholders' equity. On exercise, the cash consideration received by the Company and the associated paid in surplus are recorded as share capital.

Cenovus Replacement Stock Options

Cenovus replacement stock options are accounted for as liability instruments, which are measured at fair value at each period end using the Black-Scholes-Merton valuation model. The fair value is recognized as stock-based compensation over the vesting period. When stock options are settled for cash, the liability is reduced by the cash settlement paid. When stock options are settled for common shares, the cash consideration received by the Company and the previously recorded liability associated with the stock option is recorded as share capital.

Performance, Restricted and Deferred Share Units

PSUs, RSUs and DSUs are accounted for as liability instruments and are measured at fair value based on the market value of Cenovus's common shares at each period end. The fair value is recognized as stock-based compensation over the vesting period. Fluctuations in the fair values are recognized as stock-based compensation in the period they occur. Stock-based compensation is recorded to PP&E or E&E assets when it is directly related to exploration or development activities.

W) Financial Instruments

The Company's financial assets include cash and cash equivalents, accounts receivable and accrued revenues, restricted cash, risk management assets, net investment in finance leases, investments in the equity of companies and long-term receivables. The Company's financial liabilities include accounts payable and accrued liabilities, short-term borrowings, lease liabilities, contingent payments, risk management liabilities and long-term debt.

Financial instruments are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are not offset unless the Company has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously.

The Company characterizes its fair value measurements into a three-level hierarchy depending on the degree to which the inputs are observable, as follows:

- Level 1 inputs are quoted prices in active markets for identical assets and liabilities.
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability either directly or indirectly.
- Level 3 inputs are unobservable inputs for the asset or liability.

Classification and Measurement of Financial Assets

The initial classification of a financial asset depends upon the Company's business model for managing its financial assets and the contractual terms of the cash flows. There are three measurement categories into which the Company classified its financial assets:

- Amortized Cost: Includes assets that are held within a business model whose objective is to hold assets to collect contractual cash flows and its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest.
- FVOCI: Includes assets that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets, where its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest.
- Fair Value through Profit or Loss ("FVTPL"): Includes assets that do not meet the criteria for amortized cost or FVOCI and are measured at fair value through profit or loss. This includes all derivative financial assets.

On initial recognition, the Company may irrevocably designate a financial asset that meets the amortized cost or FVOCI criteria as measured at FVTPL if doing so eliminates or significantly reduces an accounting mismatch. On initial recognition of an equity investment that is not held-for-trading, the Company may irrevocably elect to present subsequent changes in the investment's fair value in OCI. There is no subsequent reclassification of fair value changes to earnings following the derecognition of the investment. However, dividends that reflect a return on investment continue to be recognized in net earnings. This election is made on an investment-by-investment basis.

At initial recognition, the Company measures a financial asset at its fair value and, in the case of a financial asset not at FVTPL, including transaction costs that are directly attributable to the acquisition of the financial asset. Transaction costs of financial assets carried at FVTPL are recorded as an expense in net earnings.

Financial assets are reclassified subsequent to their initial recognition only if the business model for managing those financial assets changes. The affected financial assets will be reclassified on the first day of the first reporting period following the change in the business model.

A financial asset is derecognized when the rights to receive cash flows from the asset have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership.

Impairment of Financial Assets

The Company recognizes loss allowances for expected credit losses ("ECLs") on its financial assets measured at amortized cost. Due to the nature of its financial assets, Cenovus measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit losses. Credit losses are measured as the present value of all cash shortfalls (i.e. the difference between the cash flows due to the entity in accordance with the contract and the cash flows that the Company expects to receive). ECLs are discounted at the effective interest rate of the related financial asset. The Company does not have any financial assets that contain a financing component.

Classification and Measurement of Financial Liabilities

A financial liability is initially classified as measured at amortized cost or FVTPL. A financial liability is classified as measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL on initial recognition. The classification of a financial liability is irrevocable.

Financial liabilities at FVTPL (other than financial liabilities designated at FVTPL) are measured at fair value with changes in fair value, along with any interest expense, recognized in net earnings. Other financial liabilities are initially measured at fair value less directly attributable transaction costs and are subsequently measured at amortized cost using the effective interest method. Interest expense and foreign exchange gains and losses are recognized in net earnings. Any gain or loss on derecognition is also recognized in net earnings.

A financial liability is derecognized when the obligation is discharged, cancelled or expired. When an existing financial liability is replaced by another from the same counterparty with substantially different terms, or the terms of an existing liability are substantially modified, it is treated as a derecognition of the original liability and the recognition of a new liability. When the terms of an existing financial liability are altered, but the changes are considered non-substantial, it is accounted for as a modification to the existing financial liability. Where a liability is substantially modified it is considered to be extinguished and a gain or loss is recognized in net earnings based on the difference between the carrying amount of the liability derecognized and the fair value of the revised liability. Where a liability is modified in a non-substantial way, the amortized cost of the liability is re-measured based on the new cash flows and a gain or loss is recorded in net earnings.

Derivatives

Derivative financial instruments are primarily used to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Policies and procedures are in place with respect to required documentation and approvals for the use of derivative financial instruments. Where specific financial instruments are executed, the Company assesses, both at the time of purchase and on an ongoing basis, whether the financial instrument used in the particular transaction is effective in offsetting changes in fair values or cash flows of the transaction.

Derivative financial instruments are measured at FVTPL unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using mark-to-market accounting whereby instruments are recorded in the Consolidated Balance Sheets as either an asset or liability with changes in fair value recognized in net earnings as a gain or loss on risk management. The estimated fair value of all derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

X) Adjustments to the Consolidated Statements of Earnings (Loss) and Segmented Disclosures

Certain comparative information presented in the Consolidated Statements of Earnings (Loss) within the Oil Sands segment and Corporate and Eliminations segment was revised.

During the three months ended June 30, 2022, the Company made adjustments to more appropriately reflect the cost of blending at the Lloydminster thermal and Lloydminster conventional heavy oil assets, which resulted in a reclassification of costs between purchased product and transportation and blending. An associated elimination entry was recorded in the Corporate and Eliminations segment to re-present the change in the value of condensate that was extracted at the Canadian Manufacturing operations and sold back to the Oil Sands segment. As a result, purchased product decreased and transportation and blending increased, with no impact to net earnings (loss), segment income (loss), financial position or cash flows.

In September 2022, the Company completed the divestiture of the majority of the retail fuels business. As a result, Management elected to aggregate the remaining commercial fuels business and the historical retail fuels business into the Canadian Manufacturing segment. Comparative periods have been re-presented to reflect this change, with no impact to net earnings (loss), financial position or cash flows.

The following table reconciles the amounts previously reported in the Consolidated Statements of Earnings (Loss) to the corresponding revised amounts:

Year Ended December 31, 2021

Oil Sands Segment	Previously Reported	Revisions	Segment Aggregation	Revised
Purchased Product	3,188	(784)	—	2,404
Transportation and Blending	7,841	784	—	8,625
	11,029	—	—	11,029

Canadian Manufacturing	Previously Reported	Revisions	Segment Aggregation	Revised
Gross Sales	4,472	—	1,743	6,215
Purchased Product	3,552	—	1,604	5,156
Operating	388	—	98	486
Depreciation, Depletion and Amortization	167	—	59	226
	365	—	(18)	347

Retail	Previously Reported	Revisions	Segment Aggregation	Revised
Gross Sales	2,158	—	(2,158)	—
Purchased Product	2,019	—	(2,019)	—
Operating	98	—	(98)	—
Depreciation, Depletion and Amortization	59	—	(59)	—
	(18)	—	18	—

Corporate and Eliminations Segment	Previously Reported	Revisions	Segment Aggregation	Revised
Gross Sales	(5,706)	—	415	(5,291)
Purchased Product	(4,888)	629	415	(3,844)
Transportation and Blending	(47)	(629)	—	(676)
	(771)	—	—	(771)

Consolidated	Previously Reported	Revision	Segment Aggregation	Revised
Purchased Product	23,481	(155)	—	23,326
Transportation and Blending	7,883	155	—	8,038
	31,364	—	—	31,364

Y) Recent Accounting Pronouncements

New Accounting Standards and Interpretations not yet Adopted

There are new accounting standards, amendments to accounting standards and interpretations that are effective for annual periods beginning on or after January 1, 2023, and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2022. These standards and interpretations are not expected to have a material impact on the Company's Consolidated Financial Statements or the Company's business.

4. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

The timely preparation of the Consolidated Financial Statements in accordance with IFRS requires that Management make estimates and assumptions, and use judgment regarding the reported amounts of assets and liabilities, and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

A) Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in the Company's Consolidated Financial Statements.

Joint Arrangements

The classification of a joint arrangement that is held in a separate vehicle as either a joint operation or a joint venture requires judgment. Cenovus has a 50 percent interest in the following jointly controlled entities:

- WRB Refining LP ("WRB").
- BP-Husky Refining LLC ("Toledo").

It was determined that Cenovus has the rights to the assets and obligations for the liabilities of WRB and Toledo. As a result, the joint arrangements are classified as joint operations and the Company's share of the assets, liabilities, revenues and expenses are recorded in the Consolidated Financial Statements.

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

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

- The original intention of the joint arrangements was to form an integrated North American heavy oil business. Partnerships are "flow-through" entities.
- The agreements require the partners to make contributions if funds are insufficient to meet the obligations or liabilities of the corporation and partnerships. The past development of SOSP, and the past and future development of WRB and Toledo, is dependent on funding from the partners by way of capital contribution commitments, notes payable and loans.
- WRB has third-party debt facilities to cover short-term working capital requirements. SOSP had a third-party debt facility until November 2022.
- SOSP was operated like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants in accordance with the partnership agreement. WRB and Toledo have very similar structures modified to account for the operating environment of the refining business.
- Cenovus, Phillips 66 and BP, as operators, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage, on the partners' behalf as the agreements prohibit the partners from undertaking these roles themselves. In addition, the joint arrangements do not have employees and, as such, are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

Exploration and Evaluation Assets

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

Identification of Cash-Generating Units

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

Recoveries from Insurance Claims

The Company uses estimates and assumptions on the amount recorded for insurance proceeds that are reasonably certain to be received. Accordingly, actual results may differ from these estimated recoveries.

B) Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that, if changed, could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

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

Changes to assumptions could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Crude Oil and Natural Gas Reserves

There are a number of inherent uncertainties associated with estimating crude oil and natural gas reserves. Reserves estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test recoverable amount and DD&A expense of the Company's crude oil and natural gas assets in the Oil Sands, Conventional and Offshore segments. The Company's reserves are evaluated annually and reported to the Company by its IQREs.

Recoverable Amounts

Determining the recoverable amount of a CGU or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. For the Company's upstream assets, these estimates include forward commodity prices, expected production volumes, quantity of reserves and resources, discount rates, future development and operating expenses. Recoverable amounts for the Company's manufacturing assets, crude-by-rail terminal and related ROU assets use assumptions such as throughput, forward commodity prices, discount rates, operating expenses and future capital expenditures. Recoverable amounts for the Company's real estate ROU assets use assumptions such as real estate market conditions which includes market vacancy rates and sublease market conditions, price per square footage, real estate space availability and borrowing costs. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

Decommissioning Costs

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

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

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

Income Tax Provisions

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

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

5. ACQUISITIONS

A) Sunrise Oil Sands Partnership

i) Summary of the Acquisition

On August 31, 2022, Cenovus closed the transaction with BP Canada to purchase the remaining 50 percent interest in SOSP, previously a joint operation, in northern Alberta (the "Sunrise Acquisition"). The Sunrise Acquisition had an effective date of May 1, 2022. It provides Cenovus with full ownership and further enhances Cenovus's core strength in the oil sands.

The Sunrise Acquisition has been accounted for using the acquisition method pursuant to IFRS 3. Under the acquisition method, assets and liabilities are recorded at their fair values on the date of acquisition and the total consideration is allocated to the assets acquired and liabilities assumed. The excess of consideration given over the fair value of the net assets acquired, if any, is recorded as goodwill.

ii) Identifiable Assets Acquired and Liabilities Acquired

The purchase price allocation is based on Management's best estimate of fair value and has been retrospectively adjusted to reflect items not initially identified, as well as new information obtained about the conditions that existed at the date of the Sunrise Acquisition. Changes to identifiable assets acquired and liabilities assumed includes increases of $26 million to both PP&E and decommissioning liabilities. The impact to DD&A and finance costs (including the unwinding of the discount on decommissioning liabilities) as a result of the measurement period adjustments was not material.

As at	**August 31, 2022**
100 Percent of the Identifiable Assets Acquired and Liabilities Assumed	
Cash	**9**
Accounts Receivable and Accrued Revenues	**164**
Inventories	**88**
Property, Plant and Equipment	**3,218**
Accounts Payable and Accrued Liabilities	**(313)**
Income Tax Payable	**(39)**
Decommissioning Liabilities	**(48)**
Deferred Income Tax Liabilities	**(486)**
Total Identifiable Net Assets	**2,593**

The fair value and gross contractual amount of acquired accounts receivable and accrued revenues is $164 million, all of which was collected.

iii) Total Consideration

Total consideration for the Sunrise Acquisition consisted of $600 million in cash, before closing adjustments, and Cenovus's 35 percent interest in the undeveloped Bay du Nord project offshore Newfoundland and Labrador. Cenovus also agreed to make quarterly variable payments to BP Canada for up to two years subsequent to August 31, 2022, if crude oil prices exceed a specified threshold. The maximum cumulative variable payment is $600 million. The following table summarizes the fair value of total consideration:

As at	**August 31, 2022**
Cash, Net of Closing Adjustments	**394**
Bay Du Nord	**40**
Variable Payment	**600**
Total Consideration	**1,034**

Non-monetary assets transferred as part of consideration must be re-measured at their acquisition-date fair value, with any gain or loss recognized in net earnings (loss). As a result, the Company re-measured its interest in Bay du Nord to its estimated fair value and recognized a non-cash revaluation gain of $40 million.

Cenovus agreed to make quarterly payments from SOSP to BP Canada for up to two years subsequent to the closing date for quarters in which the average Western Canadian Select ("WCS") crude oil price exceeds $52.00 per barrel. The first quarterly period ended on November 30, 2022. The quarterly payment is calculated as $2.8 million plus the difference between the average WCS price in the quarter less $53.00 multiplied by $2.8 million, for any of the eight quarters in which the average WCS price is equal to or greater than $52.00 per barrel. If the average WCS price is less than $52.00 per barrel, no payment will be made for that quarter. The maximum cumulative variable payment over the contract term is $600 million.

The variable payment is accounted for as a financial instrument. The fair value of $600 million on August 31, 2022, was estimated by calculating the present value of the expected future cash flows using an option pricing model, which assumes the probability distribution for WCS is based on the volatility of West Texas Intermediate ("WTI") options, volatility of Canadian-U.S. foreign exchange rate options and both WTI and WCS differential futures pricing. The variable payment will be re-measured at fair value with changes in fair value recognized in net earnings (loss) at each reporting date until the earlier of when the maximum $600 million in cumulative payments is reached or the eight quarters have lapsed (see Note 28).

iv) Goodwill

As at	**August 31, 2022**
Total Purchase Consideration	**1,034**
Fair Value of Pre-Existing 50 Percent Ownership Interest in Sunrise Oil Sands Partnership	**1,559**
Fair Value of Identifiable Net Assets	**(2,593)**
Goodwill	**—**

Current and deferred income tax liabilities were recognized in the purchase price allocation for the 50 percent interest acquired in SOSP. The deferred income tax liability arises from the difference between the fair value of the acquired assets and liabilities assumed, and their tax basis.

Fair Value of Pre-Existing 50 Percent Ownership Interest in Sunrise Oil Sands Partnership

Prior to the Sunrise Acquisition, Cenovus's 50 percent interest in SOSP was jointly controlled with BP Canada and met the definition of a joint operation under IFRS 11; therefore, Cenovus recognized its share of the assets, liabilities, revenues and expenses in its consolidated results. Subsequent to the Sunrise Acquisition, Cenovus controls SOSP, as defined under IFRS 10 and, accordingly SOSP has been consolidated. As required by IFRS 3, when an acquirer achieves control in stages, the previously held interest is re-measured to fair value at the acquisition date with any gain or loss recognized in net earnings (loss). The acquisition-date fair value of the previously held interest was estimated to be $1.6 billion. The net carrying value of the SOSP assets was $960 million, including previously recorded goodwill (see Note 24). As a result, Cenovus recognized a non-cash revaluation gain of $599 million ($457 million, after-tax) on the re-measurement of its existing interest in SOSP to fair value.

v) Revenue and Profit Contribution

The acquired business contributed revenues of $599 million and net earnings of $nil for the period from August 31, 2022, to December 31, 2022. If the closing of the Sunrise Acquisition had occurred on January 1, 2022, Cenovus's consolidated pro forma revenues and net earnings for the year ended December 31, 2022, would have been $67.8 billion and $6.6 billion, respectively. These amounts have been calculated using results from the acquired business, adjusting them for:

- Additional DD&A that would have been charged assuming the fair value adjustments to PP&E had applied from January 1, 2022.
- Additional accretion on the decommissioning liabilities if they had been assumed on January 1, 2022.
- The consequential tax effects.

This pro forma information is not necessarily indicative of the results that would have been obtained if the Sunrise Acquisition had actually occurred on January 1, 2022.

B) BP-Husky Refining LLC

On August 8, 2022, Cenovus announced an agreement with BP to purchase the remaining 50 percent interest in Toledo (the "Toledo Acquisition"). After closing the transaction, Cenovus will operate the Toledo Refinery. Total consideration for the transaction includes US$300 million in cash plus the value of inventory. The Toledo Acquisition will be accounted for using the acquisition method pursuant to IFRS 3. On September 20, 2022, an incident occurred at the Toledo Refinery, resulting in the shutdown of the facility. The refinery remains shut down in a safe state. The acquisition is expected to close at the end of February 2023.

C) Husky Energy Inc.

On January 1, 2021, Cenovus and Husky closed the Arrangement. The following table summarizes the details of the consideration and the recognized amounts of assets acquired and liabilities assumed at the date of the acquisition.

As at	January 1, 2021
Consideration	
Common Shares	6,111
Preferred Shares	519
Share Purchase Warrants	216
Replacement Stock Options	9
Other	17
Non-Controlling Interest	11
Total Consideration and Non-Controlling Interest	6,883
Identifiable Assets Acquired and Liabilities Assumed	
Cash	735
Restricted Cash	164
Accounts Receivable and Accrued Revenues	1,307
Inventories	1,133
Exploration and Evaluation Assets	45
Property, Plant and Equipment	13,296
Right-of-Use Assets	1,132
Long-Term Income Tax Receivable	66
Other Assets	230
Investment in Equity-Accounted Affiliates	363
Deferred Income Tax Assets, Net	1,062
Accounts Payable and Accrued Liabilities	(2,283)
Income Tax Payable	(94)
Short-Term Borrowings	(40)
Long-Term Debt	(6,602)
Lease Liabilities	(1,441)
Decommissioning Liabilities	(2,697)
Other Liabilities	(782)
Total Identifiable Net Assets	5,594
Goodwill	1,289

Goodwill of $1.3 billion was attributable to the Lloydminster thermal assets of $651 million; the Sunrise asset of $550 million; and the Tucker asset of $88 million, within the Oil Sands segment.

D) Terra Nova

On September 8, 2021, the Company acquired an additional working interest of 21 percent of the Terra Nova field in Atlantic Canada. Cenovus's working interest in the joint operation is now 34 percent. The total consideration paid was $3 million, net of closing adjustments, and the effective date of the transaction was April 1, 2021. The additional working interest acquired was accounted for as an asset acquisition. Cenovus acquired cash of $78 million and PP&E of $84 million, and assumed decommissioning liabilities of $159 million.

6. GENERAL AND ADMINISTRATIVE

For the years ended December 31,	**2022**	2021	2020
Salaries and Benefits	**204**	264	145
Administrative and Other	**297**	225	102
Stock-Based Compensation Expense (Recovery) (Note 34)	**373**	159	49
Other Incentive Benefits Expense (Recovery)	**(9)**	201	(4)
	865	849	292

7. FINANCE COSTS

For the years ended December 31,	**2022**	2021	2020
Interest Expense – Short-Term Borrowings and Long-Term Debt	**478**	557	392
Net Premium (Discount) on Redemption of Long-Term Debt [(1)]	**(29)**	121	(25)
Interest Expense – Lease Liabilities (Note 27)	**163**	171	87
Unwinding of Discount on Decommissioning Liabilities (Note 29)	**176**	199	57
Other	**37**	34	25
	825	1,082	536
Capitalized Interest	**(5)**	—	—
	820	1,082	536

(1) Includes the premium or discount on redemption, net of transaction costs and the amortization of associated fair value adjustments.

8. INTEGRATION AND TRANSACTION COSTS

Arrangement integration costs of $90 million were recognized in net earnings (loss) for the year ended December 31, 2022 (2021 – $349 million; 2020 – $29 million).

Transaction costs of $16 million were recognized in net earnings (loss) for the year ended December 31, 2022, associated with the Sunrise Acquisition and the pending Toledo Acquisition.

9. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	**2022**	2021	2020
Unrealized Foreign Exchange (Gain) Loss on Translation of:			
U.S. Dollar Debt Issued From Canada	**365**	(230)	(194)
Other	**—**	(82)	63
Unrealized Foreign Exchange (Gain) Loss	**365**	(312)	(131)
Realized Foreign Exchange (Gain) Loss	**(22)**	138	(50)
	343	(174)	(181)

10. DIVESTITURES

A) 2022 Divestitures

On January 31, 2022, the Company closed the sale of its Tucker asset in its Oil Sands segment for net proceeds of $730 million and recorded a before-tax gain of $165 million (after-tax gain – $126 million).

On February 28, 2022, the Company closed the sale of its Wembley assets in its Conventional segment for net proceeds of $221 million and recorded a before-tax gain of $76 million (after-tax gain – $58 million).

In September 2021, the Company entered into an agreement with a partner in the White Rose project in the Atlantic region that would transfer 12.5 percent of Cenovus's working interest in the White Rose field and the satellite extensions, subject to certain closing conditions. On May 31, 2022, the final closing conditions were satisfied, which included the approval of the West White Rose project restarting. Cenovus paid $50 million associated with transferring the Company's working interest, resulting in a before-tax gain of $62 million (after-tax gain – $47 million).

On June 8, 2022, the Company sold its investment in Headwater Exploration Inc. ("Headwater") for proceeds of $110 million, with no gain or loss recognized as the investment was recorded at fair value prior to the sale.

On September 13, 2022, the Company closed the sales of 337 gas stations in the historic retail fuels business, located across Western Canada and Ontario, for net cash proceeds of $404 million and recorded a before-tax loss of $74 million (after-tax loss – $56 million).

B) 2021 Divestitures

Effective May 1, 2021, the Company closed the sale of its GORR in the Marten Hills area of Alberta relating to the Conventional segment. Cenovus received cash proceeds of $102 million and recorded a before-tax gain of $60 million (after-tax gain – $47 million).

The Company sold Conventional segment assets in the Kaybob area in July 2021 and assets in the East Clearwater area in August 2021 for combined gross proceeds of approximately $82 million. A before-tax gain of $17 million (after-tax gain – $13 million) was recorded on the dispositions.

In 2020, as part of the sale of the Marten Hills assets, the Company received 50 million common shares of Headwater. On October 14, 2021, the Company sold 50 million common shares of Headwater for gross proceeds of $228 million and recorded a before-tax gain of $116 million (after-tax gain – $99 million).

C) 2020 Divestitures

On December 2, 2020, the Company sold its Marten Hills assets in northern Alberta to Headwater for total consideration of $138 million, excluding the retained GORR. A before-tax gain of $79 million was recorded on the sale (after-tax gain – $65 million). Total consideration was $33 million in cash, 50 million common shares valued at $97 million and 15 million share purchase warrants valued at $8 million at the date of close.

11. IMPAIRMENT CHARGES AND REVERSALS

At each reporting date, the Company assesses its CGUs for indicators of impairment or when facts and circumstances suggest the carrying amount may exceed the recoverable amount. Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. Goodwill is tested for impairment at least annually. For the purposes of impairment testing, goodwill is allocated to the CGU to which it relates.

A) Upstream Cash-Generating Units

i) 2022 Impairment Charges and Reversals

The Company tested the CGUs with associated goodwill for impairment as at December 31, 2022, and there were no impairments. The Company also tested the Sunrise CGU for impairment due to a decline in near-term forward prices between the date of the Sunrise Acquisition and December 31, 2022. The recoverable amount of the Sunrise CGU was in excess of its carrying amount and no impairment was recorded.

Key Assumptions

The recoverable amounts (Level 3) of Cenovus's Oil Sands CGUs that were tested for impairment are approximated using FVLCOD. Key assumptions used to estimate the present value of future net cash flows from reserves include forward prices and costs, consistent with Cenovus's IQREs, as well as costs to develop and the discount rates. Fair values for producing properties are calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates as at December 31, 2022. All reserves are evaluated as at December 31, 2022, by the Company's IQREs.

Crude Oil, NGLs and Natural Gas Prices

The forward prices as at December 31, 2022, used to determine future cash flows from crude oil, NGLs and natural gas reserves were:

	2023	2024	2025	2026	2027	Average Annual Increase Thereafter
West Texas Intermediate (US$/barrel)	**80.33**	**78.50**	**76.95**	**77.61**	**79.16**	**2.00 %**
Western Canadian Select (C$/barrel)	**76.54**	**77.75**	**77.55**	**80.07**	**81.89**	**2.00 %**
Condensate at Edmonton (C$/barrel)	**106.22**	**101.35**	**98.94**	**100.19**	**101.74**	**2.00 %**
Alberta Energy Company Natural Gas (C$/Mcf) (1)	**4.23**	**4.40**	**4.21**	**4.27**	**4.34**	**2.00 %**

(1) Assumes natural gas heating value of one million British thermal units per thousand cubic feet ("Mcf").

Discount Rates

Discounted future cash flows are determined by applying a discount rate between 14 percent and 15 percent based on the individual characteristics of the CGU, and other economic and operating factors.

Sensitivities

For the Sunrise CGU, a one percent increase in the discount rate would result in an impairment of $69 million and a five percent decrease in forward price estimates would result in an impairment of $226 million. A one percent increase in the discount rate or a five percent decrease in forward price estimates would not impact the result of the impairment tests performed on CGUs with associated goodwill.

ii) 2021 Impairment Charges and Reversals

As at December 31, 2021, there was no impairment of the Company's upstream CGUs or goodwill. As at December 31, 2021, there were indicators of impairment reversals for the Company's upstream CGUs due to an increase in forward commodity prices. An assessment was performed and indicated the recoverable amount was greater than the carrying value.

As at December 31, 2021, the recoverable amount of the Clearwater, Elmworth-Wapiti and Kaybob-Edson CGUs was estimated to be $2.0 billion. In 2020, the Company recorded a total impairment charge of $555 million in the Conventional segment due to a decline in forward commodity prices and changes in future development plans. As at December 31, 2021, the Company reversed the full amount of impairment losses of $378 million, net of dispositions and the DD&A that would have been recorded had no impairment been recorded. The reversal was primarily due to improved forward commodity prices.

The following table summarizes impairment reversals recorded in 2021 and estimated recoverable amounts as at December 31, 2021, by CGU:

	Reversal of Impairment	**Recoverable Amount**
Clearwater	145	427
Elmworth-Wapiti	115	747
Kaybob-Edson	118	837

Key Assumptions

The recoverable amounts (Level 3) of Cenovus's upstream CGUs were determined based on FVLCOD. Key assumptions in the determination of future cash flows from reserves included forward prices and costs, consistent with Cenovus's IQREs, costs to develop and the discount rates. The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates as at December 31, 2021. All reserves were evaluated as at December 31, 2021, by the Company's IQREs.

Crude Oil, NGLs and Natural Gas Prices

The forward prices as at December 31, 2021, used to determine future cash flows from crude oil, NGLs and natural gas reserves were:

	2022	2023	2024	2025	2026	Average Annual Increase Thereafter
West Texas Intermediate (US$/barrel)	72.83	68.78	66.76	68.09	69.45	2.00 %
Western Canadian Select (C$/barrel)	74.43	69.17	66.54	67.87	69.23	2.00 %
Edmonton C5+ (C$/barrel)	91.85	85.53	82.98	84.63	86.33	2.00 %
Alberta Energy Company Natural Gas (C$/Mcf) (1)	3.56	3.20	3.05	3.10	3.17	2.00 %

(1) Assumes natural gas heating value of one million British thermal units per thousand cubic feet ("Mcf").

Discount Rates

Discounted future cash flows were determined by applying a discount rate between 10 percent and 15 percent based on the individual characteristics of the CGU, and other economic and operating factors.

Sensitivities

A one percent increase in the discount rate and a five percent decrease in forward price estimates would have no impact on the amount of impairment reversals recorded in the Clearwater, Elmworth-Wapiti and Kaybob-Edson CGUs at December 31, 2021.

A one percent increase in the discount rate and a five percent decrease in forward price estimates would have no impact on the results of the impairment tests performed on CGUs with associated goodwill.

iii) 2020 Impairment Charges and Reversals

As at March 31, 2020, the Company recorded an impairment loss of $315 million in the Conventional CGU due to a decline in forward crude oil and natural gas prices. As at December 31, 2020, the Company recorded an additional impairment loss of $240 million in the Conventional CGU due to a change in future development plans.

The following table summarizes impairment losses recorded in 2020 and estimated recoverable amounts as at December 31, 2020, by CGU:

	Impairment	**Recoverable Amount**
Clearwater	260	160
Elmworth-Wapiti	120	259
Kaybob-Edson	175	384

Key Assumptions

The recoverable amounts (Level 3) of Cenovus's upstream CGUs were determined based on FVLCOD. Key assumptions in the determination of future cash flows from reserves included crude oil, NGLs and natural gas prices, costs to develop and the discount rate. The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates at December 31, 2020. All reserves were evaluated as at December 31, 2020, by the Company's IQREs.

Crude Oil, NGLs and Natural Gas Prices

The forward prices as at December 31, 2020, used to determine future cash flows from crude oil, NGLs and natural gas reserves were:

	2021	2022	2023	2024	2025	Average Annual Increase Thereafter
West Texas Intermediate (US$/barrel)	47.17	50.17	53.17	54.97	56.07	2.00 %
Western Canadian Select (C$/barrel)	44.63	48.18	52.10	54.10	55.19	2.00 %
Edmonton C5+ (C$/barrel)	59.24	63.19	67.34	69.77	71.18	2.00 %
Alberta Energy Company Natural Gas (C$/Mcf) (1)	2.88	2.80	2.71	2.75	2.80	2.00 %

(1) Assumes gas heating value of one million British thermal units per Mcf.

Discount Rates

Discounted future cash flows were determined by applying a discount rate between 10 percent and 15 percent based on the individual characteristics of the CGU, and other economic and operating factors.

Sensitivities

The sensitivity analysis below shows the impact that a change in the discount rate or forward commodity prices would have had on the calculated impairment amount used in the impairment testing completed as at December 31, 2020, for the following CGUs:

	Increase (Decrease) to Impairment Amount			
	One Percent Increase in the Discount Rate	**One Percent Decrease in the Discount Rate**	**Five Percent Increase in the Forward Price Estimates**	**Five Percent Decrease in the Forward Price Estimates**
Clearwater	7	(7)	(68)	128
Elmworth-Wapiti	10	(10)	(71)	126
Kaybob-Edson	17	(19)	(71)	140

A one percent increase in the discount rate and a five percent decrease in forward price estimates would have no impact on the results of the impairment tests performed on CGUs with associated goodwill.

B) Downstream Cash-Generating Units

i) 2022 Impairment Charges and Reversals

As at December 31, 2022, the Company identified indicators of impairment for the Toledo CGU due to the pending acquisition of the remaining 50 percent from BP and a fire at the Toledo Refinery, and for the Superior CGU with the commissioning of the asset in preparation for restart. The total carrying amount of the Toledo and Superior CGUs was greater than the recoverable amount. An impairment charge of $1.5 billion was recorded as additional DD&A in the U.S. Manufacturing segment.

As at December 31, 2022, there were also indicators of impairment reversals for the Company's Borger, Wood River and Lima CGUs due to an increase in forward crack spreads, resulting in higher margins for refined products. An assessment was performed that indicated the recoverable amount was greater than the carrying value of the associated CGUs. As at December 31, 2022, the Company reversed impairment charges of $1.2 billion, net of DD&A that would have been recorded had no impairment been recorded.

As at December 31, 2022, the aggregate recoverable amount of the U.S. Manufacturing CGUs was estimated to be $5.4 billion.

Key Assumptions

The recoverable amount (Level 3) of the U.S. Manufacturing CGUs were determined using FVLCOD. FVLCOD was calculated based on discounted after-tax cash flows using forward prices and cost estimates. Key assumptions in the determination of future cash flows included throughput, forward crude oil prices, forward crack spreads, future capital expenditures, future operating costs and discount rates. Forward crack spreads are based on an average of third-party consultant forecasts.

Crude Oil and Crack Spreads

Forward prices are based on Management's best estimate and corroborated with third-party data. As at December 31, 2022, the forward prices used to determine future cash flows were:

(US$/barrel)	2023	2024	2025	2026	2027
West Texas Intermediate	**80.33**	**78.50**	**76.95**	**77.61**	**79.16**
Differential WTI-WTS	**(0.56)**	**(0.56)**	**(0.56)**	**(0.56)**	**(0.56)**
Differential WTI-WCS	**(23.32)**	**(19.09)**	**(17.42)**	**(15.87)**	**(15.74)**
Chicago 3-2-1 Crack Spreads (WTI)	**29.37**	**24.10**	**22.12**	**21.70**	**21.67**

Subsequent prices were extrapolated using a two percent growth rate to determine future cash flows up to the year 2032.

Discount Rates

Discounted future cash flows were determined by applying a discount rate of between 15 percent to 18 percent based on the individual characteristics of the CGU, and other economic and operating factors.

Sensitivities

The sensitivity analysis below shows the impact that a change in the discount rate or forward crude oil and crack spreads would have on the net impairment amount recorded as at December 31, 2022, for the U.S. Manufacturing segment CGUs:

	Increase (Decrease) to Impairment Amount			
	One Percent Increase in the Discount Rate	**One Percent Decrease in the Discount Rate**	**Five Percent Increase in the Forward Price Estimates**	**Five Percent Decrease in the Forward Price Estimates**
U.S. Manufacturing	**69**	**(65)**	**(268)**	**268**

	Increase (Decrease) to Impairment Reversal Amount			
	One Percent Increase in the Discount Rate	**One Percent Decrease in the Discount Rate**	**Five Percent Increase in the Forward Price Estimates**	**Five Percent Decrease in the Forward Price Estimates**
U.S. Manufacturing	**(72)**	**14**	**168**	**(342)**

ii) 2021 Impairment Charges and Reversals

As at December 31, 2021, lower forward pricing that would result in lower margins for refined products was identified as an indicator of impairment for the Borger, Wood River, Lima and Toledo CGUs. As at December 31, 2021, the total carrying amounts of the Borger, Wood River and Lima CGUs were greater than the recoverable amount of $2.5 billion. An impairment charge of $1.9 billion was recorded as additional DD&A in the U.S. Manufacturing segment. As at December 31, 2021, there was no impairment of the Toledo CGU.

Key Assumptions

The recoverable amount (Level 3) of the Borger, Wood River and Lima CGUs were determined using FVLCOD. FVLCOD was calculated based on discounted after-tax cash flows using forward prices and cost estimates. Key assumptions in the determination of future cash flows included throughput, forward crude oil prices, forward crack spreads, future capital expenditures, future operating costs and discount rates. Forward crack spreads were based on an average of third-party consultant forecasts.

Crude Oil and Crack Spreads

Forward prices are based on Management's best estimate and corroborated with third-party data. As at December 31, 2021, the forward prices used to determine future cash flows were:

	2022 to 2023		2024 to 2026	
(US$/barrel)	Low	High	Low	High
West Texas Intermediate	68.78	72.83	66.76	69.45
Differential WTI-WTS	—	0.01	(0.06)	(0.06)
Differential WTI-WCS	13.54	13.67	13.75	14.30
Chicago 3-2-1 Crack Spreads (WTI)	14.87	18.44	14.68	16.81

Subsequent prices were extrapolated using a two percent growth rate to determine future cash flows up to year 2037.

Discount Rates

Discounted future cash flows were determined by applying a discount rate of 10 percent to 12 percent based on the individual characteristics of the CGU, and other economic and operating factors.

Sensitivities

The sensitivity analysis below shows the impact that a change in the discount rate or forward crude oil and crack spreads would have had on the calculated recoverable amounts used in the impairment testing completed as at December 31, 2021, for the following CGUs:

	Increase (Decrease) to Impairment Amount			
	One Percent Increase in the Discount Rate	One Percent Decrease in the Discount Rate	Five Percent Increase in the Forward Price Estimates	Five Percent Decrease in the Forward Price Estimates
Borger, Wood River and Lima	251	(283)	(990)	996

iii) 2020 Impairment Charges and Reversals

As at September 30, 2020, the recovery in demand for refined products from the impact of the novel coronavirus lagged expectations and resulted in higher than anticipated inventory levels. These factors, along with low market crack spreads and crude oil processing runs for North American refineries, were identified as indicators of impairment for the Wood River and Borger CGUs. As at September 30, 2020, the carrying amount of the Borger CGU was greater than the recoverable amount and an impairment charge of $450 million was recorded as additional DD&A in the U.S. Manufacturing segment. The recoverable amount of the Borger CGU was estimated at $692 million. As at September 30, 2020, no impairment of the Wood River CGU was identified.

Key Assumptions

The recoverable amount (Level 3) of the Borger CGU was determined using FVLCOD. The FVLCOD was calculated based on discounted after-tax cash flows using forward prices and cost estimates. Key assumptions in the determination of future cash flows included forward crude oil prices, forward crack spreads, future capital expenditures, future operating costs, terminal values and the discount rate. Forward crack spreads were based on third-party consultant average forecasts.

Crude Oil and Crack Spreads

Forward prices are based on Management's best estimate and corroborated with third-party data. As at September 30, 2020, the forward prices used to determine future cash flows were:

	2021 to 2022		2023 to 2025	
(US$/barrel)	Low	High	Low	High
West Texas Intermediate	36.36	50.84	49.66	58.74
Differential WTI-WTS	0.37	1.73	1.21	1.81
Group 3 3-2-1 Crack Spreads (WTI)	11.56	13.23	11.79	16.58

Subsequent prices were extrapolated using a two percent growth rate to determine future cash flows up to year 2035.

Discount Rates

Discounted future cash flows were determined by applying a discount rate of 10 percent based on the individual characteristics of the CGU, and other economic and operating factors.

Sensitivities

The sensitivity analysis below shows the impact that a change in the discount rate or forward commodity prices would have had on the calculated recoverable amount used in the impairment testing completed as at September 30, 2020, for the following CGU:

	Increase (Decrease) to Impairment Amount			
	One Percent Increase in the Discount Rate	**One Percent Decrease in the Discount Rate**	**Five Percent Increase in the Forward Price Estimates**	**Five Percent Decrease in the Forward Price Estimates**
Borger	89	(110)	(348)	342

12. OTHER INCOME (LOSS), NET

For the year ended December 31, 2022, the Company recorded insurance proceeds related to the 2018 incidents at the Superior Refinery and in the Atlantic region of $328 million (2021 – $120 million; 2020 – $nil).

For the year ended December 31, 2022, funding of $65 million (2021 – $42 million; 2020 – $nil) was received under the Government of Alberta's Site Rehabilitation Program which provides qualifying entities funding to abandon and reclaim oil and gas sites.

13. INCOME TAXES

A) Income Tax Expense (Recovery)

For the years ended December 31,	**2022**	2021	2020
Current Tax			
Canada	**1,252**	104	(14)
United States	**104**	—	1
Asia Pacific	**262**	171	—
Other International	**21**	1	—
Total Current Tax Expense (Recovery)	**1,639**	276	(13)
Deferred Tax Expense (Recovery)	**642**	452	(838)
	2,281	728	(851)

For the year ended December 31, 2022, the Company recorded a current tax expense related to operations in all jurisdictions that Cenovus operates. The increase is due to higher earnings compared to 2021 and the tax deductions available to calculate taxable income and losses available to offset that taxable income.

In 2021, the Company recorded a current tax expense primarily related to taxable income arising in Canada and Asia Pacific. The increase is due to Asia Pacific operations acquired in the Arrangement and higher earnings compared to 2020. In 2021, the Company recorded a $217 million deferred tax expense due to a limitation in the availability of certain U.S. tax attributes. In addition, the Company recorded a deferred tax expense of $106 million due to a rate change associated with provincial allocations.

In 2020, a deferred tax recovery was recorded due to an impairment of the Borger CGU, impairments in the Conventional segment and current period operating losses that will be carried forward, excluding unrealized foreign exchange gains and losses on long-term debt. In 2020, the Government of Alberta accelerated the reduction in the provincial corporate tax rate from 12 percent to eight percent.

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

For the years ended December 31,	**2022**	2021	2020
Earnings (Loss) From Operations Before Income Tax	**8,731**	1,315	(3,230)
Canadian Statutory Rate	**23.7%**	23.7%	24.0%
Expected Income Tax Expense (Recovery) From Operations	**2,069**	312	(775)
Effect on Taxes Resulting From:			
Statutory and Other Rate Differences	**17**	3	19
Non-Taxable Capital (Gains) Losses	**84**	63	(42)
Non-Recognition of Capital (Gains) Losses	**84**	27	(42)
Adjustments Arising From Prior Year Tax Filings	**15**	(5)	(8)
U.S. Tax Attribute Limitation	**—**	217	—
Impact of Rate Changes	**—**	106	(7)
Other	**12**	5	4
Total Tax Expense (Recovery) From Operations	**2,281**	728	(851)
Effective Tax Rate	**26.1 %**	55.4 %	26.3 %

B) Deferred Income Tax Assets and Liabilities

For the year ended December 31, 2022, deferred income tax liabilities of $486 million were recognized on the Sunrise Acquisition. The deferred income tax liability arises from the difference between the fair value of the assets acquired and the liabilities assumed, and their tax basis.

On January 1, 2021, as part of the Arrangement, the Company recorded net deferred tax assets of $1.1 billion. The net deferred tax assets consisted of $1.1 billion related to the Company's operations in the Canadian jurisdiction, $359 million related to U.S. operations, offset by a deferred tax liability of $444 million related to Asia Pacific activities. The Canadian deferred tax asset has been offset against the Canadian deferred tax liability.

The breakdown of deferred income tax liabilities and deferred income tax assets, without taking into consideration the offsetting of balances within the same tax jurisdiction, is as follows:

For the years ended December 31,	**2022**	2021
Deferred Income Tax Liabilities		
Deferred Income Tax Liabilities to be Settled Within Twelve Months	**55**	—
Deferred Income Tax Liabilities to be Settled After More Than Twelve Months	**4,460**	4,046
	4,515	4,046
Deferred Income Tax Assets		
Deferred Income Tax Assets to be Settled Within Twelve Months	**(31)**	(556)
Deferred Income Tax Assets to be Settled After More Than Twelve Months	**(747)**	(898)
	(778)	(1,454)
Net Deferred Income Tax Liability	**3,737**	2,592

The deferred income tax assets and liabilities to be settled within twelve months represents Management's estimate of the timing of the reversal of temporary differences and may not correlate to the current income tax expense of the subsequent year.

The movement in deferred income tax liabilities and assets, without taking into consideration the offsetting of balances within the same tax jurisdiction, is:

Deferred Income Tax Liabilities	**PP&E**	**Risk Management**	**Other**	**Total**
As at December 31, 2020	4,124	—	22	4,146
Charged (Credited) to Earnings	(234)	—	75	(159)
Charged (Credited) to Husky Purchase Price Allocation	59	—	—	59
As at December 31, 2021	3,949	—	97	4,046
Charged (Credited) to Earnings	**25**	**11**	**(53)**	**(17)**
Charged (Credited) to Sunrise Purchase Price Allocation	**486**	**—**	**—**	**486**
As at December 31, 2022	**4,460**	**11**	**44**	**4,515**

Deferred Income Tax Assets	Unused Tax Losses	Risk Management	Other	Total
As at December 31, 2020	(659)	(13)	(276)	(948)
Charged (Credited) to Earnings	668	1	(58)	611
Charged (Credited) to Husky Purchase Price Allocation	(656)	1	(466)	(1,121)
Charged (Credited) to Other Comprehensive Income	(8)	—	12	4
As at December 31, 2021	(655)	(11)	(788)	(1,454)
Charged (Credited) to Earnings	**490**	**11**	**158**	**659**
Charged (Credited) to Sunrise Purchase Price Allocation	—	—	—	—
Charged (Credited) to Other Comprehensive Income	**9**	—	**8**	**17**
As at December 31, 2022	**(156)**	**—**	**(622)**	**(778)**

Net Deferred Income Tax Liabilities	Total
As at December 31, 2020	3,198
Charged (Credited) to Earnings	452
Charged (Credited) to Husky Purchase Price Allocation	(1,062)
Charged (Credited) to Other Comprehensive Income	4
As at December 31, 2021	2,592
Charged (Credited) to Earnings	**642**
Charged (Credited) to Sunrise Purchase Price Allocation	**486**
Charged (Credited) to Other Comprehensive Income	**17**
As at December 31, 2022	**3,737**

The deferred income tax asset of $546 million (2021 – $694 million) represents net deductible temporary differences in the U.S. jurisdiction which has been fully recognized, as the probability of realization is expected due to forecasted taxable income. No deferred tax liability has been recognized as at December 31, 2022 and 2021 on temporary differences associated with investments in subsidiaries and joint arrangements where the Company can control the timing of the reversal of the temporary difference and the reversal is not probable in the foreseeable future.

C) Tax Pools

The approximate amounts of tax pools available, including tax losses, are:

As at December 31,	2022	2021
Canada	**8,505**	11,167
United States	**6,477**	5,915
Asia Pacific	**457**	600
	15,439	17,682

As at December 31, 2022, the above tax pools included $115 million (December 31, 2021 – $1.5 billion) of Canadian federal non-capital losses and $468 million (December 31, 2021 – $775 million) of U.S. net operating losses. These losses expire no earlier than 2035.

As at December 31, 2022, the Company had Canadian net capital losses totaling $28 million (December 31, 2021 – $102 million), which are available for carry forward to reduce future capital gains. The Company has not recognized $504 million (December 31, 2021 – $102 million) of net capital losses associated with unrealized foreign exchange losses on its U.S. denominated debt.

14. PER SHARE AMOUNTS

A) Net Earnings (Loss) Per Common Share – Basic and Diluted

For the years ended December 31,	**2022**	2021	2020
Net Earnings (Loss)	**6,450**	587	(2,379)
Effect of Cumulative Dividends on Preferred Shares	**(35)**	(34)	—
Net Earnings (Loss) – Basic and Diluted	**6,415**	553	(2,379)
Basic – Weighted Average Number of Shares	**1,951.3**	2,016.2	1,228.9
Dilutive Effect of Warrants	**44.8**	27.6	—
Dilutive Effect of Net Settlement Rights	**10.0**	1.3	—
Diluted – Weighted Average Number of Shares	**2,006.1**	2,045.1	1,228.9
Net Earnings (Loss) Per Common Share – Basic ($)	**3.29**	0.27	(1.94)
Net Earnings (Loss) Per Common Share – Diluted [(1)] [(2)] ($)	**3.20**	0.27	(1.94)

(1) *For the year ended December 31, 2022, net earnings of $52 million (2021 – $22 million; 2020 – $nil) and common shares of 1.6 million (2021 – 1.9 million; 2020 – nil) related to the assumed exercise of the Cenovus replacement stock options, were excluded from the calculation of dilutive net earnings (loss) per share. For further information on the Company's stock-based compensation plans, see Note 34.*

(2) *For the year ended December 31, 2021 and December 31, 2020, NSRs of 18 million and 31 million, respectively, were excluded from the calculation of diluted weighted average number of shares as their effect would have been anti-dilutive or their exercise prices exceeded the market price of Cenovus's common shares.*

B) Common Share Dividends

	2022		2021		2020	
For the years ended December 31,	**Per Share**	**Amount**	Per Share	Amount	Per Share	Amount
Base Dividends	**0.350**	**682**	0.088	176	0.063	77
Variable Dividends	**0.114**	**219**	—	—	—	—
Total Common Share Dividends Declared and Paid	**0.464**	**901**	0.088	176	0.063	77

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

On February 15, 2023, the Company's Board of Directors declared a first quarter base dividend of $0.105 per common share, payable on March 31, 2023, to common shareholders of record as at March 15, 2023.

C) Preferred Share Dividends

For the years ended December 31,	**2022**	2021
Series 1 First Preferred Shares	**7**	7
Series 2 First Preferred Shares	**1**	1
Series 3 First Preferred Shares	**12**	12
Series 5 First Preferred Shares	**9**	9
Series 7 First Preferred Shares	**6**	5
Total Preferred Share Dividends Declared	**35**	34

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

On January 3, 2023, the Company paid dividends on Cenovus's preferred shares as declared on November 1, 2022.

On February 15, 2023, the Company's Board of Directors declared first quarter dividends for Cenovus's preferred shares, payable on March 31, 2023, in the amount of $9 million, to preferred shareholders of record as at March 15, 2023.

15. CASH AND CASH EQUIVALENTS

As at December 31,	**2022**	2021
Cash	**3,195**	2,366
Short-Term Investments	**1,329**	507
	4,524	2,873

16. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at December 31,	**2022**	2021
Trade and Accruals	**2,962**	2,548
Prepaids and Deposits	**402**	486
Partner Advances	**—**	371
Joint Operations Receivables	**51**	225
Other [(1)]	**58**	240
	3,473	3,870

(1) As at December 31, 2022, includes insurance proceeds receivable of $nil related to the 2018 Superior Refinery incident (December 31, 2021 – $135 million).

17. INVENTORIES

As at December 31,	**2022**	2021
Product		
Crude Oil	**2,424**	2,060
Diluent	**366**	515
Natural Gas and NGLs	**50**	33
Refined Products	**1,169**	1,043
Total Product	**4,009**	3,651
Parts and Supplies	**303**	268
	4,312	3,919

For the year ended December 31, 2022, approximately $49 billion of produced and purchased inventory was recorded as an expense (2021 – approximately $34 billion).

18. ASSETS HELD FOR SALE

The Company had the following assets held for sale as at December 31, 2021, that were sold in 2022 (see Note 10):

	PP&E	**ROU Assets**	**Goodwill**	**Lease Liabilities**	**Decommissioning Liabilities**
Retail Gas Stations	498	54	—	(58)	(86)
Tucker	505	—	88	—	(33)
Wembley	159	—	—	—	(9)
	1,162	54	88	(58)	(128)

19. EXPLORATION AND EVALUATION ASSETS, NET

	Total
As at December 31, 2020	623
Acquisitions (Note 5)	45
Additions	55
Write-downs	(9)
Change in Decommissioning Liabilities	6
As at December 31, 2021	720
Additions	**37**
Write-downs	**(64)**
Change in Decommissioning Liabilities	**(12)**
Exchange Rate Movements and Other [1]	**4**
As at December 31, 2022	**685**

(1) Immediately prior to the Sunrise Acquisition, Bay du Nord had a carrying value of $nil. The Company re-measured its interest in Bay du Nord to $40 million and recognized a revaluation gain of $40 million.

For the year ended December 31, 2022, $2 million and $62 million of previously capitalized E&E costs were written off as exploration expense in the Oil Sands segment and Offshore segment, respectively (2021 – $9 million in the Oil Sands segment), as the carrying value was not considered to be recoverable.

20. PROPERTY, PLANT AND EQUIPMENT, NET

	Crude Oil and Natural Gas Properties	Processing, Transportation and Storage Assets	Manufacturing Assets	Other Assets [1]	Total
COST					
As at December 31, 2020	29,867	218	5,671	1,290	37,046
Acquisitions (Note 5)	8,633	—	3,901	846	13,380
Additions	1,368	9	1,023	115	2,515
Change in Decommissioning Liabilities	(63)	1	40	24	2
Divestitures (Note 10)	(630)	—	—	—	(630)
Transfers to Assets Held for Sale (Note 18)	(754)	—	—	(522)	(1,276)
Exchange Rate Movements and Other	22	—	(140)	(18)	(136)
As at December 31, 2021	38,443	228	10,495	1,735	50,901
Acquisitions (Note 5) [2]	**3,230**	**—**	**—**	**—**	**3,230**
Additions	**2,409**	**11**	**1,143**	**108**	**3,671**
Change in Decommissioning Liabilities	**(186)**	**(6)**	**(29)**	**(32)**	**(253)**
Divestitures (Note 5) [2]	**(557)**	**—**	**—**	**—**	**(557)**
Exchange Rate Movements and Other	**189**	**21**	**523**	**14**	**747**
As at December 31, 2022	**43,528**	**254**	**12,132**	**1,825**	**57,739**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at December 31, 2020	8,361	42	2,195	1,037	11,635
Depreciation, Depletion and Amortization	3,335	10	526	128	3,999
Impairment Charges (Note 11)	—	—	1,931	—	1,931
Impairment Reversals (Note 11)	(378)	—	—	—	(378)
Divestitures (Note 10)	(377)	—	—	—	(377)
Transfers to Assets Held for Sale (Note 18)	(90)	—	—	(24)	(114)
Exchange Rate Movements and Other	61	1	(80)	(2)	(20)
As at December 31, 2021	10,912	53	4,572	1,139	16,676
Depreciation, Depletion and Amortization [3]	**3,461**	**37**	**466**	**103**	**4,067**
Impairment Charges (Note 11)	**—**	**—**	**1,499**	**—**	**1,499**
Impairment Reversals (Note 11)	**—**	**—**	**(1,233)**	**—**	**(1,233)**
Divestitures (Note 5) [2]	**(84)**	**—**	**—**	**—**	**(84)**
Exchange Rate Movements and Other	**13**	**16**	**243**	**43**	**315**
As at December 31, 2022	**14,302**	**106**	**5,547**	**1,285**	**21,240**
CARRYING VALUE					
As at December 31, 2020	21,506	176	3,476	253	25,411
As at December 31, 2021	27,531	175	5,923	596	34,225
As at December 31, 2022	**29,226**	**148**	**6,585**	**540**	**36,499**

(1) *Includes assets within the commercial and retail fuels businesses, office furniture, fixtures, leasehold improvements, information technology and aircraft.*
(2) *In connection with the Sunrise Acquisition, Cenovus was deemed to have disposed of its pre-existing interest and reacquired it at fair value as required by IFRS 3. As at August 31, 2022, the carrying value of the pre-existing interest in SOSP's PP&E was $454 million.*
(3) *DD&A includes asset write-downs of $26 million in the Offshore segment and $25 million in the Canadian Manufacturing segment.*

Assets Under Construction

PP&E includes the following amounts in respect of assets under construction and are not subject to DD&A:

As at December 31,	2022	2021
Development and Production	2,142	2,415
Downstream	137	943
	2,279	3,358

21. RIGHT-OF-USE ASSETS, NET

	Real Estate	Transportation and Storage Assets [1]	Manufacturing Assets	Other Assets [2]	Total
COST					
As at December 31, 2020	495	977	15	15	1,502
Acquisitions (Note 5)	99	765	138	130	1,132
Additions	4	96	7	3	110
Modifications	1	20	1	—	22
Re-measurements	(2)	1	—	(3)	(4)
Transfers to Assets Held for Sale (Note 18)	—	—	—	(78)	(78)
Exchange Rate Movements and Other	(5)	(18)	—	(5)	(28)
As at December 31, 2021	592	1,841	161	62	2,656
Additions	—	22	1	2	25
Modifications	9	69	3	2	83
Re-measurements	1	3	2	1	7
Terminations	(1)	(6)	(2)	(1)	(10)
Exchange Rate Movements and Other	(2)	(89)	9	8	(74)
As at December 31, 2022	**599**	**1,840**	**174**	**74**	**2,687**
ACCUMULATED DEPRECIATION					
As at December 31, 2020	58	293	5	7	363
Depreciation	38	239	23	23	323
Impairment Charges (Note 11)	—	5	5	1	11
Terminations	—	(3)	—	—	(3)
Transfers to Assets Held for Sale (Note 18)	—	—	—	(24)	(24)
Exchange Rate Movements and Other	(4)	(14)	—	(6)	(24)
As at December 31, 2021	92	520	33	1	646
Depreciation	36	226	21	14	297
Terminations	—	(6)	—	—	(6)
Exchange Rate Movements and Other	(1)	(95)	4	(3)	(95)
As at December 31, 2022	**127**	**645**	**58**	**12**	**842**
CARRYING VALUE					
As at December 31, 2020	437	684	10	8	1,139
As at December 31, 2021	500	1,321	128	61	2,010
As at December 31, 2022	**472**	**1,195**	**116**	**62**	**1,845**

(1) Transportation and storage assets include railcars, barges, vessels, pipelines, caverns and storage tanks.
(2) Includes assets within the commercial fuels business, fleet vehicles and other equipment.

22. JOINT ARRANGEMENTS

A) Joint Operations

Cenovus has a number of joint operations in the Upstream segments. The Company also has the following joint operations held in separate entities in the U.S. Manufacturing segment.

BP-Husky Refining LLC

Cenovus holds a 50 percent interest in the Toledo Refinery with BP. BP is the operator of the refinery in Ohio and holds the remaining 50 percent interest. On August 8, 2022, Cenovus announced an agreement with BP to purchase the remaining 50 percent interest. See Note 5 for further details.

WRB Refining LP

Cenovus holds a 50 percent interest in the Wood River and Borger refineries with Phillips 66. Phillips 66 holds the remaining 50 percent interest and is the operator of the Wood River Refinery in Illinois and the Borger Refinery in Texas.

B) Joint Ventures

Husky-CNOOC Madura Ltd.

The Company holds a 40 percent interest in the jointly controlled entity, HCML, which is engaged in the exploration for and production of natural gas and NGLs in offshore Indonesia. The Company's share of equity investment income (loss) related to the joint venture is included in the Consolidated Statements of Earnings (Loss) in the Offshore segment.

Summarized below is the financial information for HCML accounted for using the equity method.

Results of Operations

For the years ended December 31,	2022	2021
Revenue	**383**	439
Expenses	**350**	395
Net Earnings (Loss)	**33**	44

Balance Sheet

As at December 31,	2022	2021
Current Assets [1]	**247**	167
Non-Current Assets	**1,926**	1,433
Current Liabilities	**160**	62
Non-Current Liabilities	**1,293**	896
Net Assets	**720**	642

(1) Includes cash and cash equivalents of $64 million (December 31, 2021 – $46 million).

For the year ended December 31, 2022, the Company's share of income from the equity-accounted affiliate was $23 million (2021 – $47 million). As at December 31, 2022, the carrying amount of the Company's share of net assets was $365 million (December 31, 2021 – $311 million). These amounts do not equal the 40 percent joint control of the revenues, expenses and net assets of HCML due to differences in the values attributed to the investment and accounting policies between the joint venture and the Company.

For the year ended December 31, 2022, the Company received $42 million of distributions from HCML (2021 – $100 million) and paid $54 million in contributions (2021 – $18 million).

Husky Midstream Limited Partnership

The Company jointly owns and is the operator of HMLP, which owns midstream assets, including pipeline, storage and other ancillary infrastructure assets in Alberta and Saskatchewan. The Company holds a 35 percent interest in HMLP, with Power Assets Holdings Ltd. holding a 49 percent interest and CK Infrastructure Holdings Ltd. holding a 16 percent interest in HMLP.

For the year ended December 31, 2022, HMLP had net earnings of $190 million (2021 – $134 million). The Company's share of (income) loss from the equity-accounted affiliate does not equal the 35 percent of the net earnings of HMLP due to the nature of the profit-sharing arrangement as defined in the partnership agreement. The Company's share of earnings will fluctuate depending on certain income thresholds of HMLP. For the year ended December 31, 2022, the Company did not record its share of pre-tax loss relating to HMLP of $23 million (2021 – loss of $22 million). The carrying value was $nil at December 31, 2022 and December 31, 2021.

As at December 31, 2022, the Company had $28 million in cumulative unrecognized losses and OCI, net of tax (December 31, 2021 – $17 million). The Company records its share of equity investment income related to the joint venture only in excess of the cumulated unrecognized loss and is included in the Consolidated Statements of Earnings (Loss) in the Oil Sands segment.

For the year ended December 31, 2022, the Company received $23 million of distributions from HMLP (2021 – $37 million) and paid $31 million in contributions (2021 – $32 million) to HMLP. The net amount of the distributions received and contributions paid are recorded in earnings from equity-accounted affiliates.

23. OTHER ASSETS

As at December 31,	**2022**	2021
Intangible Assets [1]	**19**	78
Private Equity Investments (Note 37)	**55**	53
Other Equity Investments	**—**	77
Net Investment in Finance Leases	**62**	60
Long-Term Receivables and Prepaids	**120**	77
Precious Metals	**86**	85
Other	**—**	1
	342	431

(1) For the twelve months ended December 31, 2022, $49 million of previously capitalized intangible asset costs were written off as DD&A in the Oil Sands segment as the carrying value was not considered to be recoverable.

In December 2021, all of the outstanding share purchase warrants received in the sale of the Company's Marten Hills assets to Headwater were exercised for a total cost of $30 million. At December 31, 2021, the fair value of the Headwater investment was $77 million, included in other equity investments above. The investment was carried at FVTPL.

On June 8, 2022, the Company sold its investment in Headwater for proceeds of $110 million.

24. GOODWILL

	2022	2021
Carrying Value, Beginning of Year	3,473	2,272
Goodwill Recognized (Note 5)	**—**	1,289
Goodwill Disposed of or Reclassified to Assets Held for Sale (Note 5 and Note 18)	**(550)**	(88)
Carrying Value, End of Year	**2,923**	3,473

The carrying amount of goodwill is allocated to the following CGUs:

As at December 31,	**2022**	2021
Primrose (Foster Creek)	**1,171**	1,171
Christina Lake	**1,101**	1,101
Lloydminster Thermal	**651**	651
Sunrise (Note 5)	**—**	550
	2,923	3,473

For the purposes of impairment testing, goodwill is allocated to the CGUs to which it relates. The assumptions used to test Cenovus's goodwill for impairment as at December 31, 2022, are consistent with those disclosed in Note 11. There was no impairment of goodwill as at December 31, 2022 (December 31, 2021 – $nil).

25. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31,	**2022**	2021
Accruals	**3,412**	2,722
Trade	**2,331**	2,554
Interest	**80**	128
Partner Advances	**—**	371
Employee Long-Term Incentives	**162**	317
Joint Operations Payable	**66**	28
Risk Management	**39**	116
Provisions for Onerous and Unfavourable Contracts	**25**	31
Other	**9**	86
	6,124	6,353

26. DEBT AND CAPITAL STRUCTURE

For the year ended December 31, 2022, the weighted average interest rate on outstanding debt, including the Company's proportionate share of short-term borrowings was 4.7 percent (December 31, 2021 – 4.6 percent).

A) Short-Term Borrowings

As at December 31,	Notes	**2022**	2021
Uncommitted Demand Facilities	i	**—**	—
WRB Uncommitted Demand Facilities	ii	**115**	79
Total Debt Principal		**115**	79

i) Uncommitted Demand Facilities

As at December 31, 2022, and December 31, 2021, the Company had uncommitted demand facilities of $1.9 billion in place, of which $1.4 billion may be drawn for general purposes, or the full amount may be available to issue letters of credit. As at December 31, 2022, there were outstanding letters of credit aggregating to $490 million (December 31, 2021 – $565 million) and no direct borrowings.

As at December 31, 2021, SOSP had an uncommitted demand credit facility of $10 million (the Company's proportionate share – $5 million). On November 24, 2022, the Company cancelled the SOSP uncommitted demand credit facility.

ii) WRB Uncommitted Demand Facilities

As at December 31, 2022, WRB had uncommitted demand facilities of US$450 million (the Company's proportionate share – US$225 million), which may be used to cover short-term working capital requirements (December 31, 2021 – US$300 million (the Company's proportionate share – US$150 million)). As at December 31, 2022, US$170 million was drawn on these facilities, of which the Company's proportionate share was US$85 million (C$115 million) (December 31, 2021 – US$125 million of which the Company's proportionate share was US$63 million (C$79 million)).

B) Long-Term Debt

As at December 31,	Notes	2022	2021
Committed Credit Facility [(1)]	i	—	—
U.S. Dollar Denominated Unsecured Notes	ii	6,537	9,363
Canadian Dollar Unsecured Notes	ii	2,000	2,750
Total Debt Principal		8,537	12,113
Debt Premiums (Discounts), Net, and Transaction Costs		154	272
Long-Term Debt		8,691	12,385

(1) The committed credit facility may include Bankers' Acceptances, secured overnight financing rate loans, prime rate loans and U.S. base rate loans.

i) Committed Credit Facility

At the closing of the Arrangement on January 1, 2021, the Company assumed Husky's committed credit facilities of $4.0 billion, with $350 million outstanding. In August 2021, $8.5 billion of committed facilities, which includes those assumed in the Arrangement, were cancelled and replaced with a $6.0 billion committed revolving credit facility.

On November 10, 2022, Cenovus amended its existing committed credit facility to decrease the capacity by $500 million to $5.5 billion and to extend the maturity dates by more than one year. The committed credit facility consists of a $1.8 billion tranche maturing on November 10, 2025, and a $3.7 billion tranche maturing on November 10, 2026. As at December 31, 2022, no amounts were drawn on the credit facility (December 31, 2021 – $nil).

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

For the year ended December 31, 2022, and December 31, 2021, Cenovus purchased outstanding principal amounts of the following unsecured notes:

	2022	2021
	US$ Principal	US$ Principal
U.S. Dollar Unsecured Notes		
3.95% due April 15, 2022	—	500
3.00% due August 15, 2022	—	500
3.80% due September 15, 2023	115	335
4.00% due April 15, 2024	269	481
5.38% due July 15, 2025	533	334
4.25% due April 15, 2027	589	—
4.40% due April 15, 2029	510	—
6.75% due November 15, 2039	455	—
4.45% due September 15, 2042	58	—
5.20% due September 15, 2043	29	—
	2,558	2,150
	C$ Principal	C$ Principal
Canadian Dollar Unsecured Notes		
3.55% due March 12, 2025	750	—

The principal amounts of the Company's outstanding unsecured notes are:

	2022		2021	
As at December 31,	**US$ Principal**	**C$ Principal and Equivalent**	US$ Principal	C$ Principal and Equivalent
U.S. Dollar Denominated Unsecured Notes				
3.80% due September 15, 2023	**—**	**—**	115	146
4.00% due April 15, 2024	**—**	**—**	269	341
5.38% due July 15, 2025	**133**	**181**	666	844
4.25% due April 15, 2027	**373**	**505**	962	1,220
4.40% due April 15, 2029	**240**	**324**	750	951
2.65% due January 15, 2032	**500**	**677**	500	634
5.25% due June 15, 2037	**583**	**790**	583	739
6.80% due September 15, 2037	**387**	**524**	387	490
6.75% due November 15, 2039	**935**	**1,267**	1,390	1,763
4.45% due September 15, 2042	**97**	**131**	155	197
5.20% due September 15, 2043	**29**	**39**	58	73
5.40% due June 15, 2047	**800**	**1,083**	800	1,014
3.75% due February 15, 2052	**750**	**1,016**	750	951
	4,827	**6,537**	7,385	9,363
Canadian Dollar Unsecured Notes				
3.55% due March 12, 2025		**—**		750
3.60% due March 10, 2027		**750**		750
3.50% due February 7, 2028		**1,250**		1,250
		2,000		2,750
Total Unsecured Notes		**8,537**		12,113

At the closing of the Arrangement on January 1, 2021, the Company assumed Canadian dollar unsecured notes with a fair value of $2.9 billion (notional value – $2.8 billion) and U.S. dollar denominated notes with a fair value of $3.4 billion (notional value – US$2.4 billion or C$3.0 billion). The Company closed a public offering in the U.S. in September 2021, for US$1.25 billion of senior unsecured notes, consisting of US$500 million due on January 15, 2032, and US$750 million due on February 15, 2052.

As at December 31, 2022, the Company was in compliance with all of the terms of its debt agreements. Under the terms of Cenovus's committed credit facility, the Company is required to maintain a total debt to capitalization ratio, as defined in the agreements, not to exceed 65 percent. The Company is well below this limit.

C) Mandatory Debt Payments

	U.S. Dollar Unsecured Notes		**Canadian Dollar Unsecured Notes**	**Total**
As at December 31, 2022	**US$ Principal**	**C$ Principal Equivalent**	**C$ Principal**	**C$ Principal and Equivalent**
2023	**—**	**—**	**—**	**—**
2024	**—**	**—**	**—**	**—**
2025	**133**	**181**	**—**	**181**
2026	**—**	**—**	**—**	**—**
2027	**373**	**505**	**750**	**1,255**
Thereafter	**4,321**	**5,851**	**1,250**	**7,101**
	4,827	**6,537**	**2,000**	**8,537**

D) Capital Structure

Cenovus's capital structure consists of shareholders' equity plus Net Debt. Net Debt includes the Company's short-term borrowings, and the current and long-term portions of long-term debt, net of cash and cash equivalents and short-term investments. Net Debt is used in managing the Company's capital structure. The Company's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due. To ensure financial resilience, Cenovus may, among other actions, adjust capital and operating spending, draw down on its credit facilities or repay existing debt, adjust dividends paid to shareholders, purchase the Company's common shares or preferred shares for cancellation, issue new debt, or issue new shares.

Cenovus monitors its capital structure and financing requirements using, among other things, specified financial measures consisting of Total Debt, Net Debt to adjusted earnings before interest, taxes and DD&A ("Adjusted EBITDA"), Net Debt to Adjusted Funds Flow and Net Debt to Capitalization. These measures are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength. Net Debt to Adjusted Funds Flow was a new metric as at March 31, 2022.

Cenovus targets a Net Debt to Adjusted EBITDA ratio and a Net Debt to Adjusted Funds Flow ratio of approximately 1.0 times and Net Debt at or below $4 billion over the long-term at a WTI price of US$45.00 per barrel. These measures may fluctuate periodically outside this range due to factors such as persistently high or low commodity prices.

On October 7, 2021, Cenovus filed a base shelf prospectus that allows the Company 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. Offerings under the base shelf prospectus are subject to market conditions. As at December 31, 2022, US$4.7 billion remained available under Cenovus's base shelf prospectus for permitted offerings.

Net Debt to Adjusted EBITDA

As at December 31,	**2022**	2021	2020
Short-Term Borrowings	**115**	79	121
Current Portion of Long-Term Debt	**—**	—	—
Long-Term Portion of Long-Term Debt	**8,691**	12,385	7,441
Total Debt	**8,806**	12,464	7,562
Less: Cash and Cash Equivalents	**(4,524)**	(2,873)	(378)
Net Debt	**4,282**	9,591	7,184
Net Earnings (Loss)	**6,450**	587	(2,379)
Add (Deduct):			
Finance Costs	**820**	1,082	536
Interest Income	**(81)**	(23)	(9)
Income Tax Expense (Recovery)	**2,281**	728	(851)
Depreciation, Depletion and Amortization	**4,679**	5,886	3,464
E&E Asset Write-downs	**64**	18	91
(Income) Loss From Equity-Accounted Affiliates	**(15)**	(57)	—
Unrealized (Gain) Loss on Risk Management	**(126)**	2	56
Foreign Exchange (Gain) Loss, Net	**343**	(174)	(181)
Revaluation (Gains)	**(549)**	—	—
Re-measurement of Contingent Payments	**162**	575	(80)
(Gain) Loss on Divestiture of Assets	**(269)**	(229)	(81)
Other (Income) Loss, Net	**(532)**	(309)	40
Adjusted EBITDA (1)	**13,227**	8,086	606
Net Debt to Adjusted EBITDA	**0.3x**	1.2x	11.9x

(1) Calculated on a trailing twelve-month basis.

Net Debt to Adjusted Funds Flow

As at December 31,	2022	2021	2020
Net Debt	**4,282**	9,591	7,184
Cash From (Used in) Operating Activities	**11,403**	5,919	273
(Add) Deduct:			
Settlement of Decommissioning Liabilities	**(150)**	(102)	(42)
Net Change in Non-Cash Working Capital	**575**	(1,227)	198
Adjusted Funds Flow [1]	**10,978**	7,248	117
Net Debt to Adjusted Funds Flow	**0.4x**	1.3x	61.4x

(1) Calculated on a trailing twelve-month basis.

Net Debt to Capitalization

As at December 31,	2022	2021	2020
Net Debt	**4,282**	9,591	7,184
Shareholders' Equity	**27,576**	23,596	16,707
Capitalization	**31,858**	33,187	23,891
Net Debt to Capitalization	**13 %**	29 %	30 %

27. LEASE LIABILITIES

	2022	2021
Lease Liabilities, Beginning of Year	2,957	1,757
Acquisitions (Note 5)	—	1,441
Additions	**25**	110
Interest Expense (Note 7)	**163**	171
Lease Payments	**(465)**	(471)
Modifications	**83**	22
Re-measurements	**7**	(4)
Terminations	**(5)**	(1)
Transfers to Liabilities Related to Assets Held for Sale (Note 18)	—	(10)
Exchange Rate Movements and Other	**71**	(58)
Lease Liabilities, End of Year	**2,836**	2,957
Less: Current Portion	**308**	272
Long-Term Portion	**2,528**	2,685

The Company has lease liabilities for contracts related to office space, transportation and storage assets, which includes barges, vessels, pipelines, caverns, railcars and storage tanks, commercial fuel assets and other refining and field equipment. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions.

The Company has variable lease payments related to property taxes for real estate contracts. Short-term leases are leases with terms of twelve months or less.

The Company includes extension options in the calculation of lease liabilities when the Company has the right to extend a lease term at its discretion and is reasonably certain to exercise the extension option. The Company does not have any significant termination options and the residual amounts are not material.

28. CONTINGENT PAYMENTS

A) Sunrise Oil Sands Partnership

In connection with the Sunrise Acquisition (see Note 5), Cenovus agreed to make quarterly variable payments from SOSP to BP Canada for up to eight quarters subsequent to August 31, 2022, when the average WCS crude oil price in a quarter exceeds $52.00 per barrel. The quarterly payment is calculated as $2.8 million plus the difference between the average WCS price less $53.00 multiplied by $2.8 million, for any of the eight quarters the average WCS price is equal to or greater than $52.00 per barrel. If the average WCS price is less than $52.00 per barrel, no payment will be made for that quarter. The maximum cumulative variable payment over the term of the contract is $600 million.

The variable payment will continue to be re-measured at fair value at each reporting date until the earlier of the maximum $600 million in cumulative payments is reached or the eight quarters have lapsed, with changes in fair value recognized in net earnings (loss).

The first quarterly period ended on November 30, 2022. A payment of $92 million was made in January 2023.

	Total
As at December 31, 2021	—
Initial Recognition	**600**
Liabilities Settled or Payable	**(92)**
Re-measurement [(1)]	**(89)**
As at December 31, 2022	**419**
Less: Current Portion	**263**
Long-Term Portion	**156**

(1) The variable payment is carried at fair value. Changes in fair value are recorded in net earnings (loss).

B) FCCL Partnership

On May 17, 2022, the contingent payment obligation associated with the acquisition of a 50 percent interest in the FCCL Partnership ("FCCL") from ConocoPhillips Company and certain of its subsidiaries (collectively, "ConocoPhillips") ended. The final payment of $177 million was made in July 2022 (as at December 31, 2021 – $160 million was payable). In connection with the acquisition in 2017 from ConocoPhillips, Cenovus agreed to make quarterly payments to ConocoPhillips during the five years ending May 17, 2022, for quarters in which the average WCS crude oil price exceeded $52.00 per barrel during the quarter. The quarterly payment was $6 million for each dollar that the WCS price exceeded $52.00 per barrel.

	2022	2021
Contingent Payment, Beginning of Year	236	63
Re-measurement [(1)]	**251**	575
Liabilities Settled	**(487)**	(402)
Contingent Payment, End of Year	**—**	236

(1) The contingent payment was carried at fair value. Changes in fair value were recorded in net earnings (loss).

29. DECOMMISSIONING LIABILITIES

The decommissioning provision represents the present value of the expected future costs associated with the retirement of producing well sites, upstream processing facilities, surface and subsea plant and equipment, manufacturing facilities, the commercial fuels facilities and the crude-by-rail terminal.

The aggregate carrying amount of the obligation is:

	2022	2021
Decommissioning Liabilities, Beginning of Year	3,906	1,248
Liabilities Incurred	**22**	30
Liabilities Acquired (Note 5) (1)	**48**	2,856
Liabilities Settled	**(215)**	(144)
Liabilities Divested (Note 5) (1)	**(89)**	(140)
Change in Estimated Future Cash Flows	**693**	(472)
Change in Discount Rates	**(980)**	450
Unwinding of Discount on Decommissioning Liabilities (Note 7)	**176**	199
Transfers to Liabilities Related to Assets Held for Sale (Note 18)	**—**	(128)
Exchange Rate Movements and Other	**(2)**	7
Decommissioning Liabilities, End of Year	**3,559**	3,906

(1) In connection with the Sunrise Acquisition, Cenovus was deemed to have disposed of its pre-existing interest and reacquired it at fair value as required by IFRS 3. As at August 31, 2022, the carrying value of the pre-existing interest in SOSP's decommissioning liabilities was $11 million.

As at December 31, 2022, the undiscounted amount of estimated future cash flows required to settle the obligation is $14 billion (December 31, 2021 – $14 billion). Most of these obligations are not expected to be paid for several years, or decades, and are expected to be funded from general resources at that time. The Company expects to settle approximately $250 million to $300 million of decommissioning liabilities over the next year. Revisions in estimated future cash flows resulted from a change in the timing of decommissioning liabilities over the estimated life of the reserves and an increase in cost estimates. These obligations have been discounted using a credit-adjusted risk-free rate of 6.1 percent (December 31, 2021 – 4.4 percent) and assumes an inflation rate of two percent (December 31, 2021 – two percent).

The Company deposits cash into restricted accounts that will be used to fund decommissioning liabilities in offshore China in accordance with the provisions of the regulations of the People's Republic of China. As at December 31, 2022, the Company had $209 million in restricted cash (December 31, 2021 – $186 million).

Sensitivities

Changes to the credit-adjusted risk-free rate or the inflation rate would have the following impact on the decommissioning liabilities:

	Sensitivity	**2022**		2021	
As at December 31,	**Range**	**Increase**	**Decrease**	Increase	Decrease
Credit-Adjusted Risk-Free Rate	± one percent	**(319)**	**419**	(623)	875
Inflation Rate	± one percent	**419**	**(320)**	873	(625)

30. OTHER LIABILITIES

As at December 31,	**2022**	2021
Pension and Other Post-Employment Benefit Plan	**201**	288
Provision for West White Rose Expansion Project (1)	**204**	259
Provisions for Onerous and Unfavourable Contracts	**95**	99
Employee Long-Term Incentives	**245**	74
Drilling Provisions	**31**	56
Deferred Revenue	**45**	41
Other (2)	**221**	112
	1,042	929

(1) On May 31, 2022, the Company divested of 12.5 percent of its working interest in the White Rose field and satellite extensions reducing the provision by $47 million (see Note 10). Cenovus expects to draw down the provision by $58 million in the next twelve months.

(2) As at December 31, 2022, other includes a net RVO of $101 million. Gross amounts of the RVO and RINs asset were $1.1 billion and $1.0 billion, respectively.

31. PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company provides the majority of employees with a defined contribution pension plan. The Company also provides OPEB plans to retirees and sponsors defined benefit pension plans in Canada and the U.S. (together, the "DB Pension Plan").

The DB Pension Plan provides pension benefits at retirement based on years of service and final average earnings. In Canada, future enrollment is limited to eligible employees who may elect to move from the defined contribution component to the defined benefit component for their future service. In the U.S., the defined benefit pension is closed to new members. The Company's OPEB plans provides certain retired employees with health care and dental benefits.

The Company is required to file an actuarial valuation of its registered defined benefit pension with regulators on a periodic basis. The most recently filed valuation for the Canadian defined benefit pension plan was dated December 31, 2021, and the next required actuarial valuation will be as at December 31, 2024. The most recently filed valuation for the U.S. defined benefit pension plan was dated January 1, 2022 and the next required actuarial valuation will be as at January 1, 2023.

A) Defined Benefit and OPEB Plan Obligation and Funded Status

Information related to defined benefit pension and OPEB plans, based on actuarial estimations, is:

	Pension Benefits		OPEB	
	2022	2021	**2022**	2021
Defined Benefit Obligation				
Defined Benefit Obligation, Beginning of Year	**220**	188	**225**	20
Plan Acquisition Upon the Arrangement (1)	**—**	41	**—**	224
Current Service Costs	**16**	16	**8**	9
Past Service Costs - Curtailment and Plan Amendments	**—**	(1)	**—**	(3)
Interest Costs (2)	**7**	6	**7**	6
Benefits Paid	**(12)**	(17)	**(8)**	(8)
Plan Participant Contributions	**2**	2	**—**	—
Re-measurements:				
(Gains) Losses From Experience Adjustments	**1**	4	**(2)**	10
(Gains) Losses From Changes in Demographic Assumptions	**—**	(1)	**—**	(3)
(Gains) Losses From Changes in Financial Assumptions	**(64)**	(18)	**(57)**	(30)
Exchange Rate Movements and Other	**2**	—	**1**	—
Defined Benefit Obligation, End of Year	**172**	220	**174**	225
Plan Assets				
Fair Value of Plan Assets, Beginning of Year	**159**	117	**—**	—
Plan Acquisition Upon the Arrangement (1)	**—**	32	**—**	—
Employer Contributions	**16**	9	**8**	3
Plan Participant Contributions	**2**	2	**—**	—
Benefits Paid	**(10)**	(13)	**(8)**	(3)
Interest Income (2)	**4**	3	**—**	—
Re-measurements:				
Return on Plan Assets (Excluding Interest Income)	**(26)**	9	**—**	—
Exchange Rate Movements and Other	**2**	—	**—**	—
Fair Value of Plan Assets, End of Year	**147**	159	**—**	—
Pension and OPEB (Liability) (3)	**(25)**	(61)	**(174)**	(225)

(1) The Company acquired Husky's defined benefit pension and other post-retirement benefit obligations in connection with the Arrangement. See Note 5.
(2) Based on the discount rate of the defined benefit obligation at the beginning of the year.
(3) Liabilities for the DB Pension Plan and OPEB plans are included in other liabilities on the Consolidated Balance Sheets.

The weighted average duration of the defined benefit pension and OPEB obligations are 14 years and 14 years, respectively.

B) Pension and OPEB Costs

	Pension Benefits			OPEB		
As at December 31,	**2022**	2021	2020	**2022**	2021	2020
Defined Benefit Plan Cost						
Current Service Costs	**16**	16	13	**8**	9	1
Past Service Costs - Curtailments and Plan Amendments	**—**	(1)	—	**—**	(3)	—
Net Interest Costs	**3**	3	3	**7**	6	—
Re-measurements:						
Return on Plan Assets (Excluding Interest Income)	**26**	(9)	(5)	**—**	—	—
(Gains) Losses From Experience Adjustments	**1**	4	1	**(2)**	10	(2)
(Gains) Losses From Changes in Demographic Assumptions	**—**	(1)	—	**—**	(3)	—
(Gains) Losses From Changes in Financial Assumptions	**(64)**	(18)	15	**(57)**	(30)	1
Defined Benefit Plan Cost (Recovery)	**(18)**	(6)	27	**(44)**	(11)	—
Defined Contribution Plan Cost (1)	**72**	68	22	**—**	—	—
Total Plan Cost	**54**	62	49	**(44)**	(11)	—

(1) Includes defined contribution and U.S. 401(k) plans.

C) Investment Objectives and Fair Value of Plan Assets

The objective of the asset allocation is to manage the funded status of the DB Pension Plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices. The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investment and credit rating categories.

The allocation of assets between the various types of investment funds is monitored regularly and is re-balanced as necessary. The Canadian defined benefit pension plan and U.S. defined benefit pension plan are managed independently of each other and, accordingly, the target asset allocation is reflective of their different liability profiles.

2022 Target Allocation (percent)	**Canadian Plan**	**U.S. Plan**
Equity Funds	**25% - 75%**	**21% - 51%**
Fixed Income Funds	**20% - 50%**	**55% - 74%**
Real Estate Funds	**—% - 15%**	**— %**
Listed Infrastructure Funds	**—% - 10%**	**— %**
Emerging Market Debt Funds	**—% - 10%**	**— %**
Cash and Cash Equivalents	**—% - 10%**	**— %**

The Company does not use derivative instruments to manage the risks of its plan assets. There has been no change in the process used by the Company to manage these risks from prior periods.

The fair value of the DB Pension Plan assets is:

As at December 31,	**2022**	2021
Equity Funds	**68**	77
Fixed Income Funds	**50**	54
Real Estate Funds	**9**	9
Listed Infrastructure Funds	**7**	8
Emerging Market Debt Funds	**5**	8
Cash and Cash Equivalents	**7**	2
Non-Invested Assets	**1**	1
Total Fair Value of DB Pension Plan Assets	**147**	159

Fair value of the cash and cash equivalents, equity, fixed income and listed infrastructure assets are based on the trading price of the underlying funds (Level 1). The fair value of the real estate funds reflects the appraisal valuation for each property investment (Level 2). The fair value of the non-invested assets is the discounted value of the expected future payments (Level 3).

The DB Pension Plan does not hold any direct investment in Cenovus common shares or preferred shares.

D) Funding

The DB Pension Plan is funded in accordance with applicable pension legislation. Contributions are made to trust funds administered by independent trustees. The Company's contributions to the DB Pension Plan are based on the most recent actuarial valuations, and direction of the Management Pension Committee and Human Resources and Compensation Committee of the Board of Directors.

Employees participating in the Canadian defined benefit pension are required to contribute four percent of their pensionable earnings, up to an annual maximum, and the Company provides the balance of the funding necessary to ensure benefits will be fully provided for at retirement. In the year ended December 31, 2023, the Company expects to contribute $10 million for the DB Pension Plan.

The OPEB plans are funded on an as required basis. In the year ended December 31, 2023, the Company expects to contribute $10 million for the OPEB plans.

E) Actuarial Assumptions and Sensitivities

Actuarial Assumptions

The principal weighted average actuarial assumptions used to determine benefit obligations and expenses are as follows:

	Pension Benefits			**OPEB**		
For the years ended December 31,	**2022**	2021	2020	**2022**	2021	2020
Discount Rate	**5.12 %**	2.95 %	2.50 %	**5.13 %**	2.98 %	2.50 %
Future Salary Growth Rate	**4.05 %**	4.03 %	3.97 %	**N/A**	4.94 %	4.94 %
Average Longevity (years)	**88.4**	88.3	88.3	**88.4**	88.3	88.2
Health Care Cost Trend Rate	**N/A**	N/A	N/A	**5.24 %**	5.64 %	6.00 %

Discount rates are based on market yields for high quality corporate debt instruments with maturity terms equivalent to the benefit obligations.

Sensitivities

Of the most significant actuarial assumptions, a change in discount rates and health care costs have the largest potential impact on the obligations for the DB Pension Plan and OPEB plans, with sensitivity to change as follows:

	2022		2021	
As at December 31,	**Increase**	**Decrease**	Increase	Decrease
One Percent Change:				
Discount Rate	**(43)**	**51**	(59)	76
Future Salary Growth Rate	**3**	**(3)**	4	(4)
Health Care Cost Trend Rate	**19**	**(17)**	26	(20)
One Year Change in Assumed Life Expectancy	**10**	**(10)**	4	(4)

The sensitivity analysis is based on a change in an assumption while holding all other assumptions constant; however, the changes in some assumptions may be correlated. The same methodologies have been used to calculate the sensitivity of the DB Pension Plan obligation to significant actuarial assumptions as have been applied when calculating the liability for the DB Pension Plan recorded on the Consolidated Balance Sheets.

32. SHARE CAPITAL AND WARRANTS

A) Authorized

Cenovus is authorized to issue an unlimited number of common shares, and first and second preferred shares not exceeding, in aggregate, 20 percent of the number of issued and outstanding common shares. The first and second preferred shares may be issued in one or more series with rights and conditions to be determined by the Board of Directors prior to issuance and subject to the Company's articles.

B) Issued and Outstanding – Common Shares

	2022		2021	
	Number of Common Shares (thousands)	**Amount**	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	2,001,211	17,016	1,228,870	11,040
Issued Under the Arrangement, Net of Issuance Costs (Note 5)	—	—	788,518	6,111
Issued Upon Exercise of Warrants	**9,399**	**93**	314	3
Issued Under Stock Option Plans	**11,069**	**170**	535	7
Purchase of Common Shares under NCIBs	**(112,489)**	**(959)**	(17,026)	(145)
Outstanding, End of Year	**1,909,190**	**16,320**	2,001,211	17,016

As at December 31, 2022, there were 43 million (December 31, 2021 – 30 million) common shares available for future issuance under the stock option plan.

C) Normal Course Issuer Bid

On November 4, 2021, the TSX accepted the Company's implementation of an NCIB to purchase up to 146.5 million common shares between November 9, 2021, and November 8, 2022. On November 7, 2022, the Company received approval from the TSX to renew the Company's NCIB program (the "2023 NCIB") to purchase up to 136.7 million common shares during the period from November 9, 2022, to November 8, 2023.

For the year ended December 31, 2022, the Company purchased and cancelled 112 million common shares (December 31, 2021 – 17 million) through the NCIBs. The shares were purchased at a volume weighted average price of $22.49 per common share (December 31, 2021 – $15.56) for a total of $2.5 billion (December 31, 2021 – $265 million). Paid in surplus was reduced by $1.6 billion (December 31, 2021 – $120 million), representing the excess of the purchase price of the common shares over their average carrying value.

From January 1, 2023, to February 13, 2023, the Company purchased an additional 1.4 million common shares for $36.8 million. As at February 13, 2023, 123.8 million common shares remain available for purchase under the 2023 NCIB.

D) Issued and Outstanding – Preferred Shares

For the year ended December 31, 2022, there were no preferred shares issued. As at December 31, 2022, there were 36 million preferred shares outstanding (December 31, 2021 – 36 million), with a carrying value of $519 million (December 31, 2021 – $519 million).

As at December 31, 2022	Dividend Reset Date	Dividend Rate	Number of Preferred Shares (thousands)
Series 1 First Preferred Shares	March 31, 2026	2.58 %	10,740
Series 2 First Preferred Shares [1]	Quarterly	5.86 %	1,260
Series 3 First Preferred Shares	December 31, 2024	4.69 %	10,000
Series 5 First Preferred Shares	March 31, 2025	4.59 %	8,000
Series 7 First Preferred Shares	June 30, 2025	3.94 %	6,000

(1) *The floating-rate dividend was 1.86 percent from December 31, 2021, to March 30, 2022 (January 1, 2021, to March 30, 2021 – 1.84 percent); 2.35 percent from March 31, 2022, to June 29, 2022 (March 31, 2021, to June 29, 2021 – 1.80 percent); 3.21 percent from June 30, 2022, to September 29, 2022 (June 30, 2021, to September 29, 2021 – 1.84 percent); 5.05 percent from September 30, 2022, to December 30 2022 (September 30, 2021, to December 30, 2021 – 1.92 percent); and 5.86 percent from December 31, 2022, to March 30, 2023.*

Every five years, subject to certain conditions, the holders of first preferred shares will have the right, at their option, to convert their shares into a specified series of first preferred shares. On March 31, 2026 and on March 31 every five years thereafter, holders of series 1 and series 2 first preferred shares will have such option to convert their shares into the other series. On December 31, 2024, and on December 31 every five years thereafter, holders of series 3 and series 4 first preferred shares will have such option to convert their shares into the other series. On March 31, 2025, and on March 31 every five years thereafter, holders of series 5 and series 6 first preferred shares will have such option to convert their shares into the other series. On June 30, 2025, and on June 30 every five years thereafter, holders of series 7 and series 8 first preferred shares will have such option to convert their shares into the other series.

Each series of outstanding first preferred shares are entitled to receive a cumulative quarterly dividend, payable on the last day of March, June, September and December in each year, if, as and when declared by Cenovus's Board of Directors. For the series 1, series 3, series 5 and series 7 first preferred shares, such dividend rate resets every five years at the rate equal to the sum of the five-year Government of Canada bond yield on the applicable calculation date plus 1.73 percent (series 1), 3.13 percent (series 3), 3.57 percent (series 5) and 3.52 percent (series 7). For the series 2, series 4, series 6 and series 8 first preferred shares, such dividend rate resets every quarter at the rate equal to the sum of the 90-day Government of Canada Treasury Bill yield on the applicable calculation date plus 1.73 percent (series 2), 3.13 percent (series 4), 3.57 percent (series 6) and 3.52 percent (series 8).

Every five years, subject to certain conditions, on the applicable conversion date Cenovus may, at its option, redeem all or any number of the then-outstanding series of first preferred shares by payment of an amount in cash for each share to be redeemed equal to $25.00. In addition, subject to certain conditions, on any other date Cenovus may, at its option, redeem all or any number of the then-outstanding series 2, series 4, series 6 and series 8 first preferred shares, by payment of an amount in cash for each share to be redeemed equal to $25.50. In each case, such payment shall also include all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax or other amount required to be deducted and withheld).

Second Preferred Shares

There were no second preferred shares outstanding as at December 31, 2022 (December 31, 2021 – nil).

E) Issued and Outstanding – Warrants

	2022		2021	
	Number of Warrants (thousands)	Amount	Number of Warrants (thousands)	Amount
Outstanding, Beginning of Year	65,119	215	—	—
Issued Under the Arrangement (Note 5)	—	—	65,433	216
Exercised	(9,399)	(31)	(314)	(1)
Outstanding, End of Year	**55,720**	**184**	65,119	215

The exercise price of the Cenovus warrants is $6.54 per share.

F) Paid in Surplus

Cenovus's paid in surplus reflects the Company's retained earnings prior to the split of Encana Corporation (now known as Ovintiv Inc. ("Ovintiv")) under the plan of arrangement into two independent energy companies, Ovintiv and Cenovus. In addition, paid in surplus includes stock-based compensation expense related to the Company's NSRs discussed in Note 34 and the excess of the purchase price of common shares over their average carrying value for shares purchased under the NCIBs.

	Retained Earnings Prior to Ovintiv Split	Stock-Based Compensation	Common Shares	Total
As at December 31, 2020	4,086	305	—	4,391
Stock-Based Compensation Expense	—	14	—	14
Purchase of Common Shares Under NCIBs	—	—	(120)	(120)
Common Shares Issued on Exercise of Stock Options	—	(1)	—	(1)
As at December 31, 2021	4,086	318	(120)	4,284
Stock-Based Compensation Expense	**—**	**10**	**—**	**10**
Purchase of Common Shares Under NCIBs	**—**	**—**	**(1,571)**	**(1,571)**
Common Shares Issued on Exercise of Stock Options	**—**	**(32)**	**—**	**(32)**
As at December 31, 2022	**4,086**	**296**	**(1,691)**	**2,691**

33. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Pension and Other Post-Retirement Benefits	Private Equity Instruments	Foreign Currency Translation Adjustment	Total
As at December 31, 2020	(10)	27	758	775
Other Comprehensive Income (Loss), Before Tax	47	—	(129)	(82)
Income Tax (Expense) Recovery	(9)	—	—	(9)
As at December 31, 2021	28	27	629	684
Other Comprehensive Income (Loss), Before Tax	**96**	**2**	**713**	**811**
Income Tax (Expense) Recovery	**(25)**	**—**	**—**	**(25)**
As at December 31, 2022	**99**	**29**	**1,342**	**1,470**

34. STOCK-BASED COMPENSATION PLANS

A) Employee Stock Options

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of the Company. Option exercise prices approximate the market value for the common shares on the date the options were issued. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years. Options expire after seven years.

Options issued by the Company have associated NSRs. The NSRs, in lieu of exercising the option, gives the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option. Alternatively, the holder may elect to exercise the option and receive a net cash payment equal to the excess of the market price received from the sale of the common shares over the exercise price of the option.

The NSRs vest and expire under the same terms and conditions as the underlying options.

Stock Options With Associated Net Settlement Rights

The weighted average unit fair value of NSRs granted during the year ended December 31, 2022, was $19.94 before considering forfeitures, which are considered in determining total cost for the period. The fair value of each NSR was estimated on its grant date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	**1.84 %**
Expected Dividend Yield	**0.72 %**
Expected Volatility [(1)]	**24.72 %**
Expected Life (years)	**5.75**

(1) Expected volatility has been based on historical share volatility of the Company.

The following tables summarize information related to the NSRs:

For the year ended December 31, 2022	Number of Stock Options with Associated Net Settlement Rights (thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	27,233	13.06
Granted	**2,031**	**19.94**
Exercised	**(11,599)**	**12.77**
Forfeited	**(258)**	**9.75**
Expired	**(3,058)**	**22.25**
Outstanding, End of Year	**14,349**	**12.38**

As at December 31, 2022	Outstanding			Exercisable	
	Number of Stock Options with Associated Net Settlement Rights	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number of Stock Options with Associated Net Settlement Rights	Weighted Average Exercise Price
Range of Exercise Price ($)	(thousands)	(Years)	($)	(thousands)	($)
5.00 to 9.99	**5,234**	**4.88**	**8.76**	**1,474**	**8.94**
10.00 to 14.99	**6,229**	**3.80**	**12.01**	**4,280**	**12.13**
15.00 to 19.99	**2,834**	**4.26**	**19.71**	**919**	**19.36**
20.00 to 24.99	**52**	**6.69**	**22.37**	**—**	**—**
	14,349	**4.30**	**12.38**	**6,673**	**12.42**

Cenovus Replacement Stock Options

For the year ended December 31, 2022, 6,042 thousand Cenovus replacement stock options, with a weighted average exercise price of $16.57, were exercised and net settled for cash and 103 thousand Cenovus replacement stock options were exercised with a weighted average exercise price of $14.98 and settled for 81 thousand common shares.

The Company recorded a liability of $42 million as at December 31, 2022, (December 31, 2021 – $30 million) in the Consolidated Balance Sheets for Cenovus Replacement Stock Options based on the fair value at year end using the Black-Scholes-Merton valuation model.

The following tables summarize the information related to the Cenovus replacement stock options:

For the year ended December 31, 2022	Number of Cenovus Replacement Stock Options (thousands)	Weighted Average Exercise Price ($)
Outstanding, Beginning of Year	12,256	15.21
Exercised	**(6,145)**	**16.12**
Forfeited	**(186)**	**15.85**
Expired	**(2,458)**	**20.59**
Outstanding, End of Year	**3,467**	**9.99**

As at December 31, 2022	Outstanding			Exercisable	
Range of Exercise Price ($)	Number of Cenovus Replacement Stock Options (thousands)	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price ($)	Number of Cenovus Replacement Stock Options (thousands)	Weighted Average Exercise Price ($)
3.00 to 4.99	**2,065**	**1.63**	**3.54**	**742**	**3.54**
5.00 to 9.99	**124**	**1.36**	**6.06**	**59**	**6.06**
10.00 to 14.99	**14**	**0.47**	**12.88**	**14**	**12.88**
15.00 to 19.99	**594**	**1.04**	**18.35**	**594**	**18.35**
20.00 to 24.99	**524**	**0.20**	**21.77**	**524**	**21.77**
25.00 to 29.99	**146**	**0.58**	**27.88**	**146**	**27.88**
	3,467	**1.25**	**9.99**	**2,079**	**14.21**

B) Performance Share Units

Cenovus has granted PSUs to certain employees under its Performance Share Unit Plan for Employees. PSUs are time-vested whole-share units that entitle employees to receive, upon vesting, either a common share of Cenovus or a cash payment equal to the value of a Cenovus common share. The number of PSUs eligible to vest is determined by a multiplier that ranges from zero percent to 200 percent and is based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of $216 million as at December 31, 2022, (December 31, 2021 – $61 million) in the Consolidated Balance Sheets for PSUs based on the market value of Cenovus's common shares at the end of the year. PSUs are paid out upon vesting and, as a result, the intrinsic value was $nil as at December 31, 2022.

The following table summarizes the information related to the PSUs held by Cenovus employees:

For the year ended December 31, 2022	Number of Performance Share Units (thousands)
Outstanding, Beginning of Year	7,163
Granted	**3,226**
Vested and Paid Out	**(1,413)**
Cancelled	**(465)**
Units in Lieu of Dividends	**167**
Outstanding, End of Year	**8,678**

C) Restricted Share Units

Cenovus granted RSUs to certain employees under its Restricted Share Unit Plan for Employees. RSUs are whole-share units and entitle employees to receive, upon vesting, either a common share of Cenovus or a cash payment equal to the value of a Cenovus common share. RSUs generally vest over three years.

The Company recorded a liability of $109 million as at December 31, 2022 (December 31, 2021 – $53 million) in the Consolidated Balance Sheets for RSUs based on the market value of Cenovus's common shares at the end of the year. As RSUs are paid out upon vesting, the intrinsic value of vested RSUs was $nil as at December 31, 2022.

The following table summarizes the information related to the RSUs held by Cenovus employees:

For the year ended December 31, 2022	**Number of Restricted Share Units** (thousands)
Outstanding, Beginning of Year	6,025
Granted	**3,161**
Vested and Paid Out	**(2,230)**
Cancelled	**(430)**
Units in Lieu of Dividends	**129**
Outstanding, End of Year	**6,655**

D) Deferred Share Units

Under two Deferred Share Unit Plans, Cenovus directors, officers and certain employees may receive DSUs, which are equivalent in value to a common share of the Company. Eligible employees have the option to convert either zero, 25, 50, 75 or 100 percent of their annual bonus award into DSUs. DSUs vest immediately, are redeemed in accordance with the terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

The Company recorded a liability of $40 million as at December 31, 2022 (December 31, 2021 – $20 million) in the Consolidated Balance Sheets for DSUs based on the market value of Cenovus's common shares at the end of the year. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

The following table summarizes the information related to the DSUs held by Cenovus directors, officers and employees:

For the year ended December 31, 2022	**Number of Deferred Share Units** (thousands)
Outstanding, Beginning of Year	1,256
Granted to Directors	**161**
Granted	**316**
Units in Lieu of Dividends	**30**
Redeemed	**(257)**
Outstanding, End of Year	**1,506**

E) Total Stock-Based Compensation

For the years ended December 31,	**2022**	2021	2020
Stock Options With Associated Net Settlement Rights	**15**	14	11
Cenovus Replacement Stock Options	**53**	26	—
Performance Share Units	**183**	56	19
Restricted Share Units	**100**	48	23
Deferred Share Units	**22**	15	(4)
Stock-Based Compensation Expense (Recovery)	**373**	159	49
Stock-Based Compensation Costs Capitalized	**—**	8	16
Total Stock-Based Compensation	**373**	167	65

35. EMPLOYEE SALARIES AND BENEFIT EXPENSES

For the years ended December 31,	**2022**	2021	2020
Salaries, Bonuses and Other Short-Term Employee Benefits	**1,246**	1,327	605
Post-Employment Benefits	**92**	89	33
Stock-Based Compensation (Note 34)	**373**	159	49
Other Incentive Benefits (Recovery)	**(9)**	201	(4)
Termination Benefits	**27**	180	9
	1,729	1,956	692

Stock-based compensation includes the costs recorded during the year associated with NSRs, Cenovus replacement stock options, PSUs, RSUs and DSUs.

36. RELATED PARTY TRANSACTIONS

A) Key Management Compensation

Key management includes Directors (executive and non-executive), Executive Officers, Senior Vice-Presidents and Vice-Presidents. The compensation paid or payable to key management is:

For the years ended December 31,	**2022**	2021	2020
Salaries, Director Fees and Other Short-Term Benefits	**40**	69	21
Post-Employment Benefits	**4**	4	3
Stock-Based Compensation	**140**	72	15
Other Incentive Benefits	**—**	4	1
Termination Benefits	**3**	3	6
	187	152	46

Post-employment benefits represent the present value of future pension benefits earned during the year.

B) Other Related Party Transactions

Transactions with HMLP are related party transactions as the Company has a 35 percent ownership interest (see Note 22). As the operator of the assets held by HMLP, Cenovus provides management services for which it recovers shared service costs.

The Company is also the contractor for HMLP and constructs its assets based on fixed price contracts or on a cost recovery basis with certain restrictions. For the year ended December 31, 2022, the Company charged HMLP $188 million, for construction costs and management services (2021 – $243 million).

The Company pays an access fee to HMLP for pipeline systems that are used by Cenovus's blending business. Cenovus also pays HMLP for transportation and storage services. For the year ended December 31, 2022, the Company incurred costs of $263 million, for the use of HMLP's pipeline systems, as well as transportation and storage services (2021 – $284 million).

37. FINANCIAL INSTRUMENTS

Cenovus's financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, restricted cash, net investment in finance leases, risk management assets and liabilities, investments in the equity of companies, long-term receivables, accounts payable and accrued liabilities, short-term borrowings, lease liabilities, contingent payments, long-term debt and other liabilities. Risk management assets and liabilities arise from the use of derivative financial instruments.

A) Fair Value of Non-Derivative Financial Instruments

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, and short-term borrowings approximate their carrying amount due to the short-term maturity of these instruments.

The fair values of restricted cash, net investment in finance leases and long-term receivables approximate their carrying amount due to the specific non-tradeable nature of these instruments.

Long-term debt is carried at amortized cost. The estimated fair value of long-term borrowings has been determined based on period-end trading prices of long-term borrowings on the secondary market (Level 2). As at December 31, 2022, the carrying value of Cenovus's long-term debt was $8.7 billion and the fair value was $7.8 billion (December 31, 2021 carrying value – $12.4 billion, fair value – $13.7 billion).

The Company classifies certain private equity investments as FVOCI as they are not held for trading and fair value changes are not reflective of the Company's operations. These assets are carried at fair value on the Consolidated Balance Sheets in other assets. Fair value is determined based on recent private placement transactions (Level 3) when available.

The following table provides a reconciliation of changes in the fair value of private equity investments classified as FVOCI:

	2022	2021
Fair Value, Beginning of Year	53	52
Acquisition (Note 5)	—	1
Changes in Fair Value (1)	**2**	—
Fair Value, End of Year	**55**	53

(1) Changes in fair value are recorded in OCI.

Equity investments classified as FVTPL comprise equity investments in public companies. These assets were carried at fair value on the Consolidated Balance Sheets in other assets. Fair value was determined based on quoted prices in active markets (Level 1).

B) Fair Value of Risk Management Assets and Liabilities

The Company's risk management assets and liabilities consist of crude oil, condensate, natural gas, and refined product futures, as well as renewable power contracts, power and foreign exchange swaps. The Company may also enter into swaps, forwards, and options to manage commodity and foreign exchange exposures, as well as interest rate swaps.

Crude oil, natural gas, condensate, refined product contracts and power swaps are recorded at their estimated fair value based on the difference between the contracted price and the period-end forward price for the same commodity, using quoted market prices or the period-end forward price for the same commodity extrapolated to the end of the term of the contract (Level 2). The fair value of foreign exchange rate contracts, and interest rate swaps are calculated using external valuation models that incorporate observable market data, including foreign exchange forward curves (Level 2) and interest rate yield curves (Level 2), respectively. The fair value of cross currency interest rate swaps are calculated using external valuation models that incorporate observable market data, including foreign exchange forward curves (Level 2) and interest rate yield curves (Level 2).

The fair value of renewable power contracts are calculated using internal valuation models that incorporate broker pricing for relevant markets, some observable market prices and extrapolated market prices with inflation assumptions (Level 3). The fair value of renewable power contracts are calculated by Cenovus's internal valuation team that consists of individuals who are knowledgeable and have experience in fair value techniques.

Risk management assets and liabilities are carried at fair value on the Consolidated Balance Sheets in accounts receivable and accrued revenues, and accounts payable and accrued liabilities (for short-term positions) and other liabilities and other assets (for long-term positions). Changes in fair value are recorded in the Consolidated Statements of Earnings within (gain) loss on risk management.

Summary of Risk Management Positions

	2022			2021		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Crude Oil, Natural Gas, Condensate and Refined Products	**2**	**40**	**(38)**	46	116	(70)
Power Swap Contracts	**1**	**7**	**(6)**	—	—	—
Renewable Power Contracts	**90**	**—**	**90**	—	—	—
Foreign Exchange Rate Contracts	**—**	**—**	**—**	2	—	2
	93	**47**	**46**	48	116	(68)

Level 2 prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data. Level 3 prices are sourced from partially observable data used in internal valuations.

The following table presents the Company's fair value hierarchy for risk management assets and liabilities carried at fair value:

As at December 31,	2022	2021
Level 2 – Prices Sourced From Observable Data or Market Corroboration	(44)	(68)
Level 3 – Prices Sourced From Partially Observable Data	90	—
	46	(68)

The following table provides a reconciliation of changes in the fair value of Cenovus's risk management assets and liabilities from January 1 to December 31:

	2022	2021
Fair Value of Contracts, Beginning of Year	(68)	(53)
Acquisition (Note 5)	—	(14)
Change in Fair Value of Contracts in Place at Beginning of Year	(5)	—
Change in Fair Value of Contracts Entered Into During the Year	(1,641)	(995)
Fair Value of Contracts Realized During the Year	1,762	993
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	(2)	1
Fair Value of Contracts, End of Year	46	(68)

Financial assets and liabilities are offset only if Cenovus has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. Cenovus offsets risk management assets and liabilities when the counterparty, commodity, currency and timing of settlement are the same.

	2022			2021		
	Risk Management			Risk Management		
As at December 31,	Asset	Liability	Net	Asset	Liability	Net
Recognized Risk Management Positions						
Gross Amount	153	107	46	263	331	(68)
Amount Offset	(60)	(60)	—	(215)	(215)	—
Net Amount	93	47	46	48	116	(68)

The derivative liabilities do not have credit risk-related contingent features. Due to credit practices that limit transactions according to counterparties' credit quality, the change in fair value through profit or loss attributable to changes in the credit risk of financial liabilities is immaterial.

Cenovus pledges cash collateral with respect to certain of these risk management contracts, which is not offset against the related financial liability. The amount of cash collateral required will vary daily over the life of these risk management contracts as commodity prices change. As at December 31, 2022, $211 million was pledged as cash collateral (December 31, 2021 – $114 million).

C) Fair Value of Contingent Payments

The variable payment (Level 3) associated with the Sunrise Acquisition is carried at fair value on the Consolidated Balance Sheets. Fair value is estimated by calculating the present value of the expected future cash flows using an option pricing model (Level 3), which assumes the probability distribution for WCS is based on the volatility of WTI options, volatility of Canadian-U.S. foreign exchange rate options and both WTI and WCS futures pricing discounted using a credit-adjusted risk-free rate. Fair value of the variable payment has been calculated by Cenovus's internal valuation team, which consists of individuals who are knowledgeable and have experience in fair value techniques. As at December 31, 2022, the fair value of the variable payment was estimated to be $419 million applying a credit-adjusted risk-free rate of 5.2 percent. The maximum cumulative variable payment is $600 million.

As at December 31, 2022, average WCS forward pricing for the remaining term of the variable payment is $72.79 per barrel. The average volatility of WTI options and the Canadian-U.S. foreign exchange rates was 44.2 percent and 7.6 percent, respectively. Changes in the following inputs to the option pricing model, with fluctuations in all other variables held constant, could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

As at December 31, 2022	Sensitivity Range	Increase	Decrease
WCS Forward Prices	± $10.00 per barrel	**(68)**	**157**
WTI Option Volatility	± ten percent	**(1)**	**4**
Canadian to U.S. Dollar Foreign Exchange Rate Option Volatility	± five percent	**—**	**—**

The contingent payment (Level 3) associated with the acquisition of a 50 percent interest in FCCL from ConocoPhillips Company and certain of its subsidiaries ended on May 17, 2022. The final payment was made in July 2022.

As at December 31, 2021	Sensitivity Range	Increase	Decrease
WCS Forward Prices	± $5.00 per barrel	(45)	45

The impact of a ten percent increase or decrease in WTI option price volatility and a five percent increase or decrease in the Canadian-U.S. dollar foreign exchange rate options would result in nominal unrealized gains (losses) to earnings before income tax.

D) Earnings Impact of (Gains) Losses From Risk Management Positions

For the years ended December 31,	**2022**	2021	2020
Realized (Gain) Loss	**1,762**	993	252
Unrealized (Gain) Loss (1)	**(126)**	2	56
(Gain) Loss on Risk Management	**1,636**	995	308

(1) All WTI positions related to crude oil sales price risk management were closed by June 30, 2022. In the three months ended June 30, 2022, Cenovus recorded a realized net loss related to these positions of $467 million.

Realized and unrealized gains and losses on risk management are recorded in the reportable segment to which the derivative instrument relates.

38. RISK MANAGEMENT

Cenovus is exposed to financial risks, including market risk related to commodity prices, foreign exchange rates, interest rates, commodity power prices as well as credit risk and liquidity risk.

To manage exposure to commodity price movements between when products are produced or purchased and when sold to the customer or used by Cenovus, the Company may periodically enter into financial positions as a part of ongoing operations to market the Company's production and physical inventory positions of crude oil, natural gas, condensate, refined products, and power consumption. The Company may also enter into arrangements to manage exposure to future carbon compliance costs or to offset select carbon emissions.

The Company entered into risk management positions to help capture incremental margin expected to be received in future periods at the time products will be sold and to mitigate overall exposure to fluctuations in commodity prices related to inventories and physical sales. Mitigation of commodity price volatility may utilize financial positions to protect future cash flows. To manage exposure to interest rate volatility, the Company periodically enters into interest rate swap contracts. To mitigate the Company's exposure to foreign exchange rate fluctuations, the Company periodically enters into foreign exchange contracts. To manage interest costs on short-term borrowings, the Company periodically enters into cross currency interest rate swaps. To manage electricity costs associated with the production and transportation of crude oil, the Company may enter into power swaps and other energy instruments, including renewable power contracts. To manage exposure to future carbon costs, power prices, or to generate potential offsets for carbon emissions, the Company may enter into renewable power contracts.

As at December 31, 2022, the fair value of risk management positions was a net asset of $46 million and consisted of crude oil, natural gas, condensate, refined products, power and foreign exchange rate instruments. As at December 31, 2022, there were foreign exchange contracts with a notional value of US$168 million outstanding (December 31, 2021 – US$144 million) and no interest rate contracts or cross currency interest rate swap contracts (December 31, 2021 – $nil) outstanding.

Net Fair Value of Risk Management Positions

As at December 31, 2022	Notional Volumes [(1)(2)]	Terms [(3)]	Weighted Average Price [(1)(2)]	Fair Value Asset (Liability)
Futures Contracts Related to Blending [(4)]				
WTI Fixed – Sell	**3.2 MMbbls**	**January 2023 - June 2024**	**US$80.35/bbl**	**1**
WTI Fixed – Buy	**2.3 MMbbls**	**February 2023 - June 2024**	**US$79.93/bbl**	**—**
Power Swap Contacts				**(6)**
Renewable Power Contracts				**90**
Other Financial Positions [(5)]				**(39)**
Total Fair Value				**46**

(1) Million barrels ("MMbbls"). Barrel ("bbl").
(2) Notional volumes and weighted average price represent various contracts over the respective terms. The notional volumes and weighted average price may fluctuate from month to month as it represents the averages for various individual contracts with different terms.
(3) Contract terms represent various individual contracts with different terms, and range from one month to eighteen months.
(4) Condensate related futures contract positions consist of WTI contracts to help manage condensate price exposure.
(5) Other financial positions consist of risk management positions related to WCS, heavy oil and condensate differential contracts, Belvieu fixed price contracts, reformulated blendstock for oxygenate blending gasoline contracts, heating oil and natural gas fixed price contracts, natural gas basis contracts and the Company's U.S. manufacturing and marketing activities.

A) Commodity Price, Foreign Exchange and Interest Rate Risk

i) Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of forward commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments.

The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy does not allow the use of derivative instruments for speculative purposes.

The Company has used crude oil, natural gas and refined product swaps, futures, basis price risk management contracts and, if entered into, forwards, options, as well as condensate futures and swaps. These derivative instruments are used to partially mitigate exposure to the commodity price risk on its crude oil sales and to protect both near-term and future cash flows. Cenovus has entered into a number of transactions to help protect against widening light/heavy crude oil price differentials and to manage exposure to commodity price movements between when products are produced or purchased and when sold to the customer or used by Cenovus. In addition, the Company has entered into risk management positions to help mitigate the risk to incremental margin expected to be received in future periods at the time products will be sold. The Company has used commodity futures and swaps, as well as differential price risk management contracts to partially mitigate its exposure to the commodity price risk on its condensate transactions. Natural gas fixed price and basis instruments are used to partially mitigate its natural gas commodity price risk.

ii) Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of Cenovus's financial assets or liabilities. As Cenovus operates in North America, fluctuations in the exchange rate between the U.S./Canadian dollar can have a significant effect on reported results.

Cenovus's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of the U.S. dollar debt issued from Canada (see Note 9). As at December 31, 2022, Cenovus had US$4.8 billion in U.S. dollar debt (December 31, 2021 – US$7.4 billion).

iii) Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect earnings, cash flows and valuations. Cenovus has the flexibility to partially mitigate its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt. To manage exposure to interest rate volatility, the Company periodically enters into interest rate swap contracts. As at December 31, 2022, Cenovus had no interest rate swap contracts outstanding (December 31, 2021 – $nil). To manage interest costs on short-term borrowings, the Company periodically enters into cross currency interest rate swaps. As at December 31, 2022, Cenovus had no cross currency interest rate swap contracts outstanding (December 31, 2021 – $nil).

iv) Commodity Price, Foreign Exchange and Interest Rate Sensitivities

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to independent fluctuations in commodity prices and foreign exchange rates, with all other variables held constant. Management believes the fluctuations identified in the table below are a reasonable measure of volatility.

The impact of fluctuating commodity prices and foreign exchange rates on the Company's open risk management positions could have resulted in an unrealized gain (loss) impacting earnings before income tax as follows:

As at December 31, 2022	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$10.00/bbl Applied to WTI, Condensate and Related Hedges	**1**	**(1)**
WCS and Condensate Differential Price [1]	± US$2.50/bbl Applied to Differential Hedges Tied to Production	**13**	**(13)**
WCS (Hardisty) Differential Price	± US$5.00/bbl Applied to WCS Differential Hedges Tied to Production	**(1)**	**1**
Refined Products Commodity Price	± US$10.00/bbl Applied to Heating Oil and Gasoline Hedges	**(2)**	**2**
Natural Gas Basis Price	± US$0.50/MCF Applied to Natural Gas Basis Hedges	**1**	**(1)**
Power Commodity Price	± C$20.00/Megawatt Hour Applied to Power Hedges	**113**	**(113)**
U.S. to Canadian Dollar Exchange Rate	± $0.05 in the U.S. to Canadian Dollar Exchange Rate	**14**	**(17)**

(1) Excludes WCS (Hardisty) differential.

As at December 31, 2021	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$5.00/bbl Applied to WTI, Condensate and Related Hedges	(225)	225
WCS and Condensate Differential Price	± US$2.50/bbl Applied to WCS and Differential Hedges Tied to Production	4	(4)
Refined Products Commodity Price	± US$5.00/bbl Applied to Heating Oil and Gasoline Hedges	(2)	2
U.S. to Canadian Dollar Exchange Rate	± $0.05 in the U.S. to Canadian Dollar Exchange Rate	11	(12)

In respect of these financial instruments, the impact of changes in the Canadian per U.S. dollar exchange rate would have resulted in a change to the foreign exchange (gain) loss as follows:

As at December 31,	2022	2021
$0.05 Increase in the Canadian per U.S. Dollar Foreign Exchange Rate	**246**	372
$0.05 Decrease in the Canadian per U.S. Dollar Foreign Exchange Rate	**(246)**	(372)

Management believes the fluctuations identified in the table above are a reasonable measure of volatility.

As at December 31, 2022, the increase or decrease in net earnings for a one percent change in interest rates on floating rate debt amounts to $1 million (December 31, 2021 – $1 million). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

B) Credit Risk

Credit risk arises from the potential that the Company may incur a financial loss if a counterparty to a financial instrument fails to meet its financial or performance obligations in accordance with agreed terms. Cenovus has in place a Credit Policy approved by the Audit Committee and the Board of Directors, which is designed to ensure that its credit exposures are within an acceptable risk level. The Credit Policy outlines the roles and responsibilities related to credit risk, sets a framework for how credit exposures will be measured, monitored and mitigated, and sets parameters around credit concentration limits.

Cenovus assesses the credit risk of new counterparties and continues risk-based monitoring of all counterparties on an ongoing basis. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. Cenovus's exposure to its counterparties is within its credit policy tolerances. The maximum credit risk exposure associated with accounts receivable and accrued revenues, net investment in finance leases, risk management assets and long-term receivables is the total carrying value.

As at December 31, 2022, approximately 85 percent (December 31, 2021 – 94 percent) of the Company's accruals, receivables related to Cenovus's joint arrangements, trade receivables and net investment in finance leases were with investment grade counterparties, and 99 percent of the Company's accounts receivable were outstanding for less than 60 days. The associated average expected credit loss on these accounts was 0.4 percent as at December 31, 2022 (December 31, 2021 – 0.1 percent).

C) Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity risk through the active management of cash and debt, and by maintaining appropriate access to credit, which may be impacted by the Company's credit ratings. As disclosed in Note 26, over the long term, Cenovus targets a Net Debt to Adjusted EBITDA ratio and Net Debt to Adjusted Funds Flow ratio of approximately 1.0 times at the bottom of the commodity price cycle to manage the Company's overall debt position.

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn capacity on its committed credit facility and uncommitted demand facilities as well as availability under its base shelf prospectus. As at December 31, 2022, the Company's sources of capital included:

- $4.5 billion in cash and cash equivalents.
- $5.5 billion available on its committed credit facility.
- $1.4 billion available on its uncommitted demand facilities, of which $1.0 billion may be drawn for general purposes, or the full amount may be available to issue letters of credit.
- US$140 million (C$190 million) on the Company's proportionate share of the uncommitted demand facilities from WRB.
- US$4.7 billion unused capacity under its base shelf prospectus, availability of which is dependent on market conditions.

Undiscounted cash outflows relating to financial liabilities are:

As at December 31, 2022	1 Year	Years 2 and 3	Years 4 and 5	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	6,124	—	—	—	**6,124**
Short-Term Borrowings (1)	115	—	—	—	**115**
Long-Term Debt (1)	401	983	2,014	11,196	**14,594**
Contingent Payments	271	167	—	—	**438**
Lease Liabilities (1)	426	746	596	2,889	**4,657**

As at December 31, 2021	1 Year	Years 2 and 3	Years 4 and 5	Thereafter	Total
Accounts Payable and Accrued Liabilities	6,353	—	—	—	6,353
Short-Term Borrowings (1)	79	—	—	—	79
Long-Term Debt (1)	561	1,608	2,603	14,892	19,664
Contingent Payments	238	—	—	—	238
Lease Liabilities (1)	453	794	634	3,192	5,073

(1) Principal and interest, including current portion if applicable.

39. SUPPLEMENTARY CASH FLOW INFORMATION

A) Working Capital

As at December 31,	**2022**	2021
Total Current Assets	**12,430**	11,988
Total Current Liabilities	**8,021**	7,305
Working Capital	**4,409**	4,683

As at December 31, 2022, adjusted working capital was $4.7 billion (December 31, 2021 – $3.8 billion), excluding assets held for sale of $nil (December 31, 2021 – $1.3 billion), the current portion of the contingent payments of $263 million (December 31, 2021 – $236 million) and liabilities related to assets held for sale of $nil (December 31, 2021 – $186 million).

Changes in non-cash working capital is as follows:

For the years ended December 31,	**2022**	2021	2020
Accounts Receivable and Accrued Revenues	**838**	(953)	77
Income Tax Receivable	**(58)**	(1)	(12)
Inventories	**(143)**	(1,646)	450
Accounts Payable and Accrued Liabilities	**(524)**	1,645	(338)
Income Tax Payable	**1,000**	87	(17)
Total Change in Non-Cash Working Capital	**1,113**	(868)	160
Net Change in Non-Cash Working Capital – Operating Activities	**575**	(1,227)	198
Net Change in Non-Cash Working Capital – Investing Activities	**538**	359	(38)
Total Change in Non-Cash Working Capital	**1,113**	(868)	160

For the years ended December 31,	**2022**	2021	2020
Interest Paid	**647**	811	381
Interest Received	**78**	24	5
Income Taxes Paid	**723**	209	18

B) Reconciliation of Liabilities

The following table provides a reconciliation of liabilities to cash flows arising from financing activities:

	Dividends Payable	**Short-Term Borrowings**	**Long-Term Debt**	**Lease Liabilities**
As at December 31, 2019	—	—	6,699	1,916
Changes From Financing Cash Flows:				
Net Issuance (Repayment) of Short-Term Borrowings	—	117	—	—
(Repayment) of Revolving Long-Term Debt	—	—	(220)	—
Issuance of Long-Term Debt	—	—	1,326	—
(Repayment) of Long-Term Debt	—	—	(112)	—
Principal Repayment of Leases	—	—	—	(197)
Base Dividends Paid on Common Shares	(77)	—	—	—
Non-Cash Changes:				
Net Premium (Discount) on Redemption of Long-Term Debt	—	—	(25)	—
Finance Costs	—	—	5	—
Lease Additions	—	—	—	49
Lease Modifications	—	—	—	(2)
Lease Re-measurements	—	—	—	(2)
Lease Terminations	—	—	—	(1)
Base Dividends Declared on Common Shares	77	—	—	—
Exchange Rate Movements and Other	—	4	(232)	(6)
As at December 31, 2020	—	121	7,441	1,757

	Dividends Payable	Short-Term Borrowings	Long-Term Debt	Lease Liabilities
As at December 31, 2020	—	121	7,441	1,757
Acquisition (Note 5)	—	40	6,602	1,441
Changes From Financing Cash Flows:				
Net Issuance (Repayment) of Short-Term Borrowings	—	(77)	—	—
(Repayment) of Revolving Long-Term Debt	—	—	(350)	—
Issuance of Long-Term Debt	—	—	1,557	—
(Repayment) of Long-Term Debt	—	—	(2,870)	—
Principal Repayment of Leases	—	—	—	(300)
Base Dividends Paid on Common Shares	(176)	—	—	—
Dividends Paid on Preferred Shares	(34)	—	—	—
Non-Cash Changes:				
Net Premium (Discount) on Redemption of Long-Term Debt	—	—	121	—
Finance Costs	—	—	(59)	—
Lease Additions	—	—	—	110
Lease Modifications	—	—	—	22
Lease Re-measurements	—	—	—	(4)
Lease Termination	—	—	—	(1)
Transfers to Liabilities Related to Assets Held for Sale	—	—	—	(58)
Base Dividends Declared on Common Shares	176	—	—	—
Dividends Declared on Preferred Shares	34	—	—	—
Exchange Rate Movements and Other	—	(5)	(57)	(10)
As at December 31, 2021	—	79	12,385	2,957
Changes From Financing Cash Flows:				
Net Issuance (Repayment) of Short-Term Borrowings	**—**	**34**	**—**	**—**
(Repayment) of Long-Term Debt	**—**	**—**	**(4,149)**	**—**
Principal Repayment of Leases	**—**	**—**	**—**	**(302)**
Base Dividends Paid on Common Shares	**(682)**	**—**	**—**	**—**
Variable Dividends Paid on Common Shares	**(219)**	**—**	**—**	**—**
Dividends Paid on Preferred Shares	**(26)**	**—**	**—**	**—**
Non-Cash Changes:				
Net Premium (Discount) on Redemption of Long-Term Debt	**—**	**—**	**(29)**	**—**
Finance Costs	**—**	**—**	**(28)**	**—**
Lease Additions	**—**	**—**	**—**	**25**
Lease Modifications	**—**	**—**	**—**	**83**
Lease Re-measurements	**—**	**—**	**—**	**7**
Lease Terminations	**—**	**—**	**—**	**(5)**
Base Dividends Declared on Common Shares	**682**	**—**	**—**	**—**
Variable Dividends Declared on Common Shares	**219**	**—**	**—**	**—**
Dividends Declared on Preferred Shares	**35**	**—**	**—**	**—**
Exchange Rate Movements and Other	**—**	**2**	**512**	**71**
As at December 31, 2022	**9**	**115**	**8,691**	**2,836**

40. COMMITMENTS AND CONTINGENCIES

A) Commitments

Cenovus has entered into various commitments in the normal course of operations. Commitments that have original maturities less than one year are excluded from the table below. Future payments for the Company's commitments are below:

As at December 31, 2022	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	Total
Transportation and Storage (1)	1,747	2,011	1,542	1,416	1,360	13,005	**21,081**
Product Purchases	1,626	1,509	922	922	922	3,457	**9,358**
Real Estate (2)	48	50	50	50	54	604	**856**
Obligation to Fund Equity-Accounted Affiliate (3)	92	105	96	96	91	143	**623**
Other Long-Term Commitments (4)	381	90	75	74	65	395	**1,080**
Total Payments	3,894	3,765	2,685	2,558	2,492	17,604	**32,998**

As at December 31, 2021	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	Total
Transportation and Storage (1)	1,677	1,958	1,853	1,488	1,350	13,244	21,570
Product Purchases (5)	1,684	1,682	1,593	731	731	4,204	10,625
Real Estate (2)	44	43	52	54	57	658	908
Obligation to Fund Equity-Accounted Affiliate (3)	68	85	99	90	90	210	642
Other Long-Term Commitments (4)	436	83	72	63	81	366	1,101
Total Payments	3,909	3,851	3,669	2,426	2,309	18,682	34,846

(1) Includes transportation commitments of $9.1 billion (December 31, 2021 – $8.1 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 commencement of the contract.
(2) Relates to the non-lease components of lease liabilities consisting of operating costs and unreserved parking for office space. Excludes committed payments for which a provision has been provided.
(3) Relates to funding obligations for HCML.
(4) Includes Cenovus's proportionate share of the commitments related to WRB, Toledo and the Offshore segment.
(5) Previously included in transportation and storage.

As at December 31, 2022, the Company had commitments with HMLP that include $2.2 billion related to long-term transportation and storage commitments (December 31, 2021 – $2.6 billion).

There were also outstanding letters of credit aggregating to $490 million (December 31, 2021 – $565 million) issued as security for financial and performance conditions under certain contracts.

B) Contingencies

Legal Proceedings

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

Income Tax Matters

The tax regulations and legislation and interpretations thereof in the various jurisdictions in which Cenovus operates are continually changing. As a result, there are usually a number of tax matters under review. Management believes that the provision for taxes is adequate.

Financial Statistics

($ millions, except per share amounts)	Three Months Ended					Twelve Months Ended	
Revenues	**Dec. 31, 2022**	Sep. 30, 2022	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2021	**Dec. 31, 2022**	Dec. 31, 2021
Upstream							
Oil Sands [1]	**5,947**	7,642	8,557	8,136	5,983	**30,282**	20,631
Conventional	**1,061**	942	990	1,041	953	**4,034**	3,085
Offshore [2]	**424**	428	556	535	486	**1,943**	1,674
Total Upstream Revenue	**7,432**	9,012	10,103	9,712	7,422	**36,259**	25,390
Downstream							
Canadian Manufacturing [3]	**1,772**	2,168	2,245	1,607	1,856	**7,792**	6,215
U.S. Manufacturing	**6,608**	8,719	8,474	6,509	6,154	**30,310**	20,043
Total Downstream Revenue	**8,380**	10,887	10,719	8,116	8,010	**38,102**	26,258
Corporate and Eliminations [3]	**(1,749)**	(2,428)	(1,657)	(1,630)	(1,706)	**(7,464)**	(5,291)
Total Revenues	**14,063**	17,471	19,165	16,198	13,726	**66,897**	46,357
Operating Margin							
Upstream							
Oil Sands [1]	**1,639**	2,220	2,921	2,199	1,890	**8,979**	6,365
Conventional	**248**	290	434	263	260	**1,235**	803
Offshore [2]	**337**	339	476	458	408	**1,610**	1,420
Total Upstream Operating Margin [4]	**2,224**	2,849	3,831	2,920	2,558	**11,824**	8,588
Downstream							
Canadian Manufacturing [3]	**278**	246	54	121	139	**699**	573
U.S. Manufacturing	**280**	244	793	423	(97)	**1,740**	212
Total Downstream Operating Margin [4]	**558**	490	847	544	42	**2,439**	785
Total Operating Margin [5]	**2,782**	3,339	4,678	3,464	2,600	**14,263**	9,373
Cash From (Used in) Operating Activities and Adjusted Funds Flow							
Cash From (Used in) Operating Activities	**2,970**	4,089	2,979	1,365	2,184	**11,403**	5,919
Deduct (Add Back):							
Settlement of Decommissioning Liabilities	**(49)**	(55)	(27)	(19)	(35)	**(150)**	(102)
Net Change in Non-Cash Working Capital	**673**	1,193	(92)	(1,199)	271	**575**	(1,227)
Adjusted Funds Flow [5]	**2,346**	2,951	3,098	2,583	1,948	**10,978**	7,248
Per Share - Basic [5]	**1.22**	1.53	1.57	1.30	0.97	**5.63**	3.59
Per Share - Diluted [5]	**1.19**	1.49	1.53	1.27	0.97	**5.47**	3.54
Net Earnings (Loss)							
Net Earnings (Loss)	**784**	1,609	2,432	1,625	(408)	**6,450**	587
Per Share - Basic	**0.40**	0.83	1.23	0.81	(0.21)	**3.29**	0.27
Per Share - Diluted	**0.39**	0.81	1.19	0.79	(0.21)	**3.20**	0.27
Capital Investment							
Oil Sands [1]	**681**	360	376	375	402	**1,792**	1,019
Conventional	**156**	67	33	88	87	**344**	222
Offshore							
Asia Pacific [2]	**3**	3	2	—	—	**8**	21
Atlantic	**82**	78	89	53	45	**302**	154
Total Offshore	**85**	81	91	53	45	**310**	175
Manufacturing							
Canadian Manufacturing [3]	**40**	24	38	15	23	**117**	68
U.S. Manufacturing	**285**	300	267	207	252	**1,059**	995
Total Manufacturing	**325**	324	305	222	275	**1,176**	1,063
Corporate	**27**	34	17	8	26	**86**	84
Total Capital Investment	**1,274**	866	822	746	835	**3,708**	2,563

(1) On August 31, 2022, we purchased the remaining 50 percent interest in Sunrise Oil Sands Partnership ("Sunrise").

(2) Excludes amounts related to the Husky-CNOOC Madura Ltd. joint venture ("HCML"), which is accounted for using the equity method. For the year ended December 31, 2022, our portion of the capital investment in HCML was $74 million (December 31, 2021 – $8 million).

(3) In September 2022, the Company completed the divestiture of the majority of the retail fuels business. As a result, Management elected to aggregate the remaining commercial fuels business and the historical retail fuels business into the Canadian Manufacturing segment.Comparative periods have been re-presented to reflect this change.

(4) Specified financial measure. See the Specified Financial Measures Advisory of this Supplemental.

(5) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this Supplemental.

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics

	Three Months Ended					Twelve Months Ended	
Financial Metrics	**Dec. 31, 2022**	Sep. 30, 2022	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2021	**Dec. 31, 2022**	Dec. 31, 2021
Free Funds Flow [1]	**1,072**	2,085	2,276	1,837	1,113	**7,270**	4,685
Excess Free Funds Flow [1] [2]	**786**	1,756	2,020	2,615	1,169	**n/a**	n/a
Long-Term Debt	**8,691**	8,774	11,228	11,744	12,385	**8,691**	12,385
Net Debt	**4,282**	5,280	7,535	8,407	9,591	**4,282**	9,591
Net Debt to Adjusted Funds Flow [3] (times)	**0.4**	0.5	0.8	1.0	1.3	**0.4**	1.3
Net Debt to Adjusted EBITDA (times)	**0.3**	0.4	0.6	0.8	1.2	**0.3**	1.2
Income Tax & Exchange Rates							
Effective Tax Rates Using:							
Net Earnings (Loss)						**26.1%**	55.4%
Foreign Exchange Rates							
US$ per C$1							
Average	**0.737**	0.766	0.783	0.790	0.794	**0.769**	0.798
Period End	**0.738**	0.730	0.776	0.800	0.789	**0.738**	0.789
RMB per C$1							
Average	**5.241**	5.246	5.180	5.014	5.073	**5.170**	5.147
Common Share Information							
Commons Shares Outstanding (millions)							
Period End	**1,909.2**	1,922.7	1,949.6	1,981.7	2,001.2	**1,909.2**	2,001.2
Average - Basic	**1,917.0**	1,927.9	1,971.3	1,989.9	2,012.3	**1,951.3**	2,016.2
Average - Diluted	**1,967.2**	1,978.7	2,029.4	2,041.5	2,012.3	**2,006.1**	2,045.1
Base Dividends ($ per share)	**0.105**	0.105	0.105	0.035	0.035	**0.350**	0.088
Variable Dividends ($ per share)	**0.114**	—	—	—	—	**0.114**	—
Closing Price							
Toronto Stock Exchange (C$ per share)	**26.27**	21.22	24.49	20.84	15.51	**26.27**	15.51
New York Stock Exchange (US$ per share)	**19.41**	15.37	19.01	16.68	12.28	**19.41**	12.28
Total Share Volume Traded (millions)	**1,026.6**	1,287.4	1,682.8	1,883.5	1,485.7	**5,880.3**	5,689.1
Selected Average Benchmark Prices							
Crude Oil Prices							
US$/bbl							
Dated Brent	**88.71**	100.85	113.78	101.41	79.73	**101.19**	70.73
West Texas Intermediate (“WTI”)	**82.65**	91.55	108.41	94.29	77.19	**94.23**	67.91
Differential Dated Brent - WTI	**6.06**	9.30	5.37	7.12	2.54	**6.96**	2.82
Western Canadian Select at Hardisty (“WCS”)	**56.99**	71.69	95.61	79.76	62.55	**76.01**	54.87
Differential WTI - WCS	**25.66**	19.86	12.80	14.53	14.64	**18.22**	13.04
Mixed Sweet Blend	**81.04**	89.51	107.91	91.33	74.09	**92.45**	64.03
Condensate (C5 @ Edmonton)	**83.40**	87.26	108.34	96.09	79.13	**93.78**	68.20
Differential WTI - Condensate (Premium)/Discount	**(0.75)**	4.29	0.07	(1.80)	(1.94)	**0.45**	(0.29)
Synthetic @ Edmonton	**86.79**	100.34	114.46	93.05	75.40	**98.66**	66.28
Differential WTI - Synthetic (Premium)/Discount	**(4.14)**	(8.79)	(6.05)	1.24	1.79	**(4.43)**	1.63
C$/bbl							
WCS	**77.42**	93.53	122.07	101.01	78.71	**98.51**	68.73
Synthetic @ Edmonton	**117.87**	130.90	146.13	117.84	94.94	**128.19**	83.04
Mixed Sweet Blend	**110.06**	116.80	137.77	115.66	93.29	**120.07**	80.23
Refining Benchmarks (US$/bbl)							
Chicago 3-2-1 Crack Spreads [4]	**32.87**	38.87	46.50	18.35	16.06	**34.15**	17.54
Group 3 3-2-1 Crack Spreads [4]	**29.99**	38.57	44.35	19.94	15.82	**33.21**	17.82
Renewable Identification Numbers (“RINs”)	**8.54**	8.11	7.80	6.44	6.11	**7.72**	6.76
Natural Gas Prices							
AECO 7A Monthly Index [5] (C$/Mcf)	**5.58**	5.81	6.28	4.59	4.94	**5.56**	3.56
NYMEX [6] (US$/Mcf)	**6.26**	8.20	7.17	4.95	5.83	**6.64**	3.84
Differential NYMEX - AECO (US$/Mcf)	**2.15**	3.75	2.25	1.32	1.91	**2.36**	1.00

(1) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this Supplemental.
(2) New financial metric as of June 30, 2022.
(3) New financial metric as of March 31, 2022.
(4) 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. 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.
(5) Alberta Energy Company ("AECO") natural gas monthly index.
(6) New York Mercantile Exchange (“NYMEX”) natural gas monthly index.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Before Royalties

Upstream Production Volumes	Three Months Ended					Twelve Months Ended	
	Dec. 31, 2022	Sep. 30, 2022	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2021	**Dec. 31, 2022**	Dec. 31, 2021
Crude Oil and Natural Gas Liquids (Mbbls/d)							
Oil Sands Bitumen							
Foster Creek	**195.9**	182.4	187.8	197.9	211.8	**191.0**	179.9
Christina Lake	**250.3**	252.8	228.8	254.1	250.9	**246.5**	236.8
Sunrise (1)	**44.8**	30.9	25.3	24.1	25.2	**31.3**	25.9
Lloydminster Thermal	**102.5**	102.1	98.4	96.3	99.0	**99.9**	97.7
Tucker (2)	**—**	—	—	6.4	19.1	**1.6**	21.0
Oil Sands Heavy Crude Oil							
Lloydminster Conventional Heavy Oil	**15.8**	16.8	16.4	16.2	18.9	**16.3**	20.2
Total Oil Sands	**609.3**	585.0	556.7	595.0	624.9	**586.6**	581.5
Conventional (3)							
Light Crude Oil	**6.8**	6.9	7.5	8.2	7.2	**7.5**	8.4
Natural Gas Liquids (4)	**26.1**	19.9	24.7	24.5	22.5	**23.8**	25.6
Total Conventional	**32.9**	26.8	32.2	32.7	29.7	**31.3**	34.0
Offshore Natural Gas Liquids							
Asia Pacific - China	**9.9**	9.5	9.4	10.6	10.4	**9.8**	10.0
Asia Pacific - Indonesia (5)	**2.5**	2.7	2.6	2.5	2.7	**2.6**	2.7
Offshore Light Crude Oil							
Atlantic	**10.3**	9.1	13.3	13.7	10.6	**11.6**	14.1
Total Offshore	**22.7**	21.3	25.3	26.8	23.7	**24.0**	26.8
Total Liquids Production	**664.9**	633.1	614.2	654.5	678.3	**641.9**	642.3
Conventional Natural Gas (MMcf/d)							
Oil Sands	**11.9**	12.6	12.0	12.8	12.4	**12.3**	12.6
Conventional (3) (6)	**555.3**	596.1	601.2	555.0	574.3	**576.1**	597.6
Offshore							
Asia Pacific - China	**222.8**	215.5	224.9	257.7	254.2	**230.1**	244.1
Asia Pacific - Indonesia (5)	**62.0**	44.5	44.1	39.8	42.6	**47.6**	41.2
Total Conventional Natural Gas Production	**852.0**	868.7	882.2	865.3	883.5	**866.1**	895.5
Total Production (7) (MBOE/d)	**806.9**	777.9	761.5	798.6	825.3	**786.2**	791.5

Effective Royalty Rates (8) (Excluding Realized (Gain) Loss on Risk Management)							
Oil Sands							
Foster Creek	**32.9%**	33.6%	32.1%	24.4%	24.5%	**30.5%**	21.0%
Christina Lake	**26.5%**	34.8%	31.9%	29.1%	26.4%	**30.8%**	23.6%
Sunrise (1)	**7.6%**	9.6%	6.9%	5.5%	5.3%	**7.3%**	4.1%
Lloydminster Thermal	**12.6%**	9.4%	9.8%	11.3%	10.1%	**10.6%**	9.1%
Lloydminster Conventional Heavy Oil	**12.0%**	11.3%	6.5%	9.3%	10.0%	**9.9%**	8.7%
Conventional (3)	**15.9%**	15.9%	13.6%	15.9%	10.7%	**15.4%**	10.3%
Offshore							
Asia Pacific - China	**5.8%**	5.7%	5.4%	5.4%	6.6%	**5.6%**	5.9%
Asia Pacific - Indonesia (5)	**34.2%**	40.0%	52.2%	45.7%	45.3%	**42.7%**	23.1%
Atlantic	**1.1%**	1.8 %	(8.0)%	6.1%	6.0%	**(0.5)%**	6.7%

(1) On August 31, 2022, we purchased the remaining 50 percent interest in Sunrise.
(2) Sale of the Tucker asset closed on January 31, 2022.
(3) Sale of the Wembley assets closed on February 28, 2022.
(4) Natural gas liquids include condensate volumes.
(5) Production volumes and associated 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.
(6) Includes production used for internal consumption by the Oil Sands segment of 561 MMcf per day and 520 MMcf per day for the three months ended and twelve months ended December 31, 2022, respectively (533 MMcf per day and 517 MMcf per day for the three and twelve months months ended December 31, 2021, respectively).
(7) Natural gas volumes have been converted to barrels of oil equivalent ("BOE") on the basis of six thousand cubic feet ("Mcf") to one barrel ("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 to 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.
(8) Effective royalty rates are equal to royalty expense divided by product revenue, net of transportation.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Netbacks [1]

Oil Sands	Three Months Ended Dec. 31, 2022	Sep. 30, 2022	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2021	Twelve Months Ended Dec. 31, 2022	Dec. 31, 2021
Foster Creek							
Bitumen ($/bbl)							
Sales Price	**75.43**	89.42	122.03	101.06	72.86	**97.27**	66.50
Royalties	**19.87**	26.01	35.72	21.56	15.67	**25.80**	11.75
Transportation and Blending	**15.06**	11.96	10.37	9.90	9.27	**11.78**	10.51
Operating	**11.44**	13.46	14.31	11.19	10.31	**12.59**	10.74
Netback	**29.06**	37.99	61.63	58.41	37.61	**47.10**	33.50
Christina Lake							
Bitumen ($/bbl)							
Sales Price	**64.07**	81.18	114.10	94.18	65.49	**88.02**	60.22
Royalties	**15.14**	26.13	34.04	24.65	15.67	**24.84**	12.69
Transportation and Blending	**6.95**	6.02	6.75	6.37	6.32	**6.51**	6.19
Operating	**9.75**	9.19	11.77	9.22	8.82	**9.94**	8.24
Netback	**32.23**	39.84	61.54	53.94	34.68	**46.73**	33.10
Sunrise							
Bitumen ($/bbl)							
Sales Price	**57.20**	79.96	128.54	102.01	68.62	**86.05**	67.10
Royalties	**3.54**	6.42	7.81	4.98	3.06	**5.38**	2.23
Transportation and Blending	**10.97**	13.17	12.48	13.15	10.36	**12.26**	12.14
Operating	**15.55**	17.74	21.22	16.95	14.03	**17.49**	17.15
Netback	**27.14**	42.63	87.03	66.93	41.17	**50.92**	35.58
Other Oil Sands [2]							
Bitumen & Heavy Crude Oil ($/bbl)							
Sales Price	**69.24**	84.95	127.98	90.75	70.23	**92.82**	62.20
Royalties	**8.16**	7.52	11.76	9.19	7.95	**9.12**	6.40
Transportation and Blending	**3.59**	3.57	3.28	3.51	3.31	**3.49**	4.01
Operating	**23.84**	20.87	24.58	20.63	18.02	**22.45**	16.64
Netback	**33.65**	52.99	88.36	57.42	40.95	**57.76**	35.15
Total Oil Sands [3] ($/BOE)							
Sales Price	**68.06**	84.29	119.98	95.90	69.00	**91.70**	62.82
Royalties	**14.40**	21.26	28.94	19.72	13.22	**20.96**	10.38
Transportation and Blending	**9.08**	7.72	7.51	7.23	6.76	**7.89**	7.23
Operating	**13.52**	13.40	15.70	12.51	11.76	**13.75**	11.52
Netback	**31.06**	41.91	67.83	56.44	37.26	**49.10**	33.69
Conventional [3]							
Total Conventional ($/BOE)							
Sales Price	**48.09**	44.07	57.11	42.84	39.07	**48.15**	31.20
Royalties	**6.05**	5.81	7.34	6.29	4.01	**6.38**	3.06
Transportation and Blending	**4.08**	2.43	2.97	3.18	1.50	**3.16**	1.53
Operating	**11.67**	11.77	10.02	11.33	10.96	**11.18**	10.66
Netback	**26.29**	24.06	36.78	22.04	22.60	**27.43**	15.95

(1) The components of each netback are Specified Financial Measures. Netbacks contain a non-GAAP Financial Measure. See the Specified Financial Measures Advisory of this Supplemental.

(2) Includes Tucker, Lloydminster thermal and Lloydminster conventional heavy oil. Sale of the Tucker asset closed on January 31, 2022.

(3) 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 to 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.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Netbacks [1]

Offshore	Three Months Ended					Twelve Months Ended	
	Dec. 31, 2022	Sep. 30, 2022	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2021	**Dec. 31, 2022**	Dec. 31, 2021
Asia Pacific - China							
Natural Gas Liquids ($/bbl)							
Sales Price	**97.62**	100.28	112.96	108.05	90.71	**104.67**	76.51
Royalties	**5.49**	5.68	6.42	6.15	5.30	**5.93**	4.38
Operating	**5.36**	6.66	5.86	4.68	5.19	**5.61**	5.18
Conventional Natural Gas ($/mcf)							
Sales Price	**13.16**	12.58	12.43	12.61	12.39	**12.69**	11.90
Royalties	**0.77**	0.72	0.66	0.67	0.85	**0.70**	0.70
Operating	**0.89**	1.13	0.98	0.78	0.80	**0.94**	0.85
Asia Pacific - China Total [2] ($/BOE)							
Sales Price	**82.89**	80.68	82.25	82.09	77.57	**81.99**	72.44
Royalties	**4.80**	4.63	4.44	4.43	5.15	**4.57**	4.25
Operating	**5.36**	6.73	5.89	4.66	4.88	**5.62**	5.10
Netback	**72.73**	69.32	71.92	73.00	67.54	**71.80**	63.09
Asia Pacific - Indonesia [3]							
Natural Gas Liquids ($/bbl)							
Sales Price	**115.56**	137.20	148.31	119.91	108.68	**130.62**	92.36
Royalties	**66.96**	81.50	110.02	70.28	68.21	**82.56**	30.99
Operating	**13.76**	12.08	13.66	13.54	12.23	**13.24**	9.55
Conventional Natural Gas ($/mcf)							
Sales Price	**9.09**	6.94	8.34	9.67	9.16	**8.53**	8.96
Royalties	**1.99**	1.18	2.40	3.46	2.95	**2.20**	1.45
Operating	**2.32**	2.01	2.29	2.25	2.01	**2.22**	1.59
Asia Pacific - Indonesia Total [2] ($/BOE)							
Sales Price	**66.50**	66.97	76.06	74.82	69.72	**70.66**	64.52
Royalties	**22.74**	26.80	39.69	34.23	31.58	**30.19**	14.93
Operating	**13.88**	12.05	13.70	13.51	12.08	**13.32**	9.55
Netback	**29.88**	28.12	22.67	27.08	26.06	**27.15**	40.04
Asia Pacific - Total [3]							
Natural Gas Liquids ($/bbl)							
Sales Price	**101.25**	108.39	120.75	110.30	94.41	**110.05**	79.83
Royalties	**17.91**	22.33	29.27	18.29	18.25	**21.84**	9.95
Operating	**7.06**	7.85	7.58	6.36	6.64	**7.20**	6.10
Conventional Natural Gas ($/mcf)							
Sales Price	**12.27**	11.62	11.76	12.22	11.93	**11.98**	11.48
Royalties	**1.03**	0.80	0.94	1.04	1.15	**0.96**	0.81
Operating	**1.20**	1.28	1.20	0.97	0.97	**1.16**	0.95
Asia Pacific - Total [2] ($/BOE)							
Sales Price	**79.37**	78.19	81.16	81.04	76.34	**79.96**	71.19
Royalties	**8.64**	8.65	10.65	8.76	9.28	**9.16**	5.94
Operating	**7.19**	7.70	7.27	5.95	6.01	**7.00**	5.80
Netback	**63.54**	61.84	63.24	66.33	61.05	**63.80**	59.45

(1) The components of each netback are Specified Financial Measures. Netbacks contain a non-GAAP Financial Measure. See the Specified Financial Measures Advisory of this Supplemental.

(2) 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 to 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.

(3) Per unit values 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.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Netbacks [1]

Offshore (continued)	Three Months Ended Dec. 31, 2022	Sep. 30, 2022	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2021	Twelve Months Ended Dec. 31, 2022	Dec. 31, 2021
Atlantic							
Light Crude Oil ($/bbl)							
Sales Price	**128.76**	158.42	146.38	130.87	103.63	**140.65**	91.01
Royalties	**1.39**	2.86	(11.50)	7.81	6.20	**(0.74)**	6.07
Transportation and Blending	**5.05**	5.86	2.40	3.51	3.62	**3.79**	3.02
Operating	**72.43**	47.23	30.57	36.06	32.61	**42.03**	28.34
Netback	**49.89**	102.47	124.91	83.49	61.20	**95.57**	53.58

Total Upstream [2] [3]	Dec. 31, 2022	Sep. 30, 2022	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2021
Total Upstream ($/BOE)							
Sales Price	**69.77**	83.43	114.40	94.12	70.02	**90.34**	62.99
Royalties	**14.19**	19.69	25.89	18.61	12.76	**19.56**	9.80
Transportation and Blending	**8.57**	7.01	6.81	6.71	6.02	**7.28**	6.33
Operating	**9.59**	10.87	10.61	10.06	9.36	**10.29**	9.82
Netback	**37.42**	45.86	71.09	58.74	41.88	**53.21**	37.04

(1) The components of each netback are Specified Financial Measures. Netbacks contain a non-GAAP Financial Measure. See the Specified Financial Measures Advisory of this Supplemental.
(2) 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 to 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.
(3) Excludes natural gas volumes used for internal consumption by the Oil Sands segment. For the three months ended September 30, 2022, the total upstream netback has been represented.

Downstream

Canadian Manufacturing	Three Months Ended Dec. 31, 2022	Sep. 30, 2022	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2021	Twelve Months Ended Dec. 31, 2022	Dec. 31, 2021
Total							
Heavy Crude Oil Throughput (Mbbls/d)	**94.3**	98.5	80.9	98.1	108.3	**92.9**	106.5
Heavy Crude Oil Throughput Capacity (Mbbls/d)	**110.5**	110.5	110.5	110.5	110.5	**110.5**	110.5
Crude Utilization [1] (%)	**85%**	89%	73%	89%	98%	**84%**	96%
Refining Margin [2] [3] ($/bbl)	**46.21**	38.88	24.87	24.28	19.07	**33.92**	18.09
Unit Operating Expense [3] [4] ($/bbl)	**13.78**	11.72	19.93	10.99	7.99	**13.91**	7.55
Lloydminster Upgrader							
Production (Mbbls/d)	**69.2**	71.9	63.7	71.9	81.7	**69.1**	80.2
Heavy Crude Oil Throughput [5] (Mbbls/d)	**68.4**	71.3	64.6	70.7	80.4	**68.7**	79.0
Upgrading Differential ($/bbl)	**45.30**	39.36	26.47	20.50	19.71	**32.84**	16.83
Refining Margin [2] [3] ($/bbl)	**52.60**	38.33	25.54	26.98	21.26	**36.04**	18.96
Unit Operating Expense [4] ($/bbl)	**12.83**	11.25	16.26	10.59	7.44	**12.65**	7.28
Lloydminster Refinery							
Production (Mbbls/d)	**26.0**	27.3	16.3	27.5	27.9	**24.3**	27.6
Heavy Crude Oil Throughput (Mbbls/d)	**25.9**	27.2	16.3	27.4	27.9	**24.2**	27.5
Refining Margin [2] [3] ($/bbl)	**29.36**	40.33	22.22	17.33	12.77	**27.91**	15.60
Unit Operating Expense [4] ($/bbl)	**16.30**	12.96	36.14	12.01	9.81	**17.49**	8.35
Ethanol							
Ethanol Production (millions of litres/d)	**0.8**	0.8	0.7	0.8	0.8	**0.8**	0.7
Rail							
Volumes Loaded [6] (Mbbls/d)	**2.8**	1.4	—	3.0	9.6	**1.8**	12.1
Sales at U.S. Locations [7] (Mbbls/d)	**0.7**	1.4	—	8.5	8.1	**2.6**	12.3
Fuel [8]							
Number of Fuel Outlets (average)	**170**	454	511	515	522	**413**	531
Fuel Sales Volume (millions of litres/d)	**4.8**	6.9	6.4	6.6	7.1	**6.2**	6.9
Fuel Sales per Outlet (thousands of litres/d)	**28.5**	15.2	12.6	12.8	13.5	**15.0**	13.0

(1) Based on crude oil name plate capacity.
(2) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this Supplemental.
(3) Comparative information has been represented for the Canadian Manufacturing refining margins to include marketing activities.
(4) Specified financial measure. See the Specified Financial Measures Advisory of this Supplemental.
(5) Upgrader throughput includes diluent returned to the field.
(6) Volumes loaded and transported outside of Alberta, Canada.
(7) Includes sales volumes from third-party purchases.
(8) On September 13, 2022, we closed the sales of 337 gas stations within our retail fuels network. We retained our commercial fuels business, which includes approximately 170 cardlock, bulk plant and travel centre locations.

SUPPLEMENTAL INFORMATION *(unaudited)*

Downstream

U.S. Manufacturing	Three Months Ended Dec. 31, 2022	Sep. 30, 2022	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2021	Twelve Months Ended Dec. 31, 2022	Dec. 31, 2021
Total							
Crude Oil Processed (Mbbls/d)	**379.2**	435.0	376.4	403.7	361.6	**400.8**	401.5
Heavy Crude Oil	**127.4**	145.2	106.5	153.8	155.8	**116.1**	138.7
Light/Medium Crude Oil	**251.8**	289.8	269.9	249.9	205.8	**284.7**	262.8
Crude Oil Throughput Capacity (1) (Mbbls/d)	**552.5**	502.5	502.5	502.5	502.5	**552.5**	502.5
Crude Utilization (2) (%)	**75%**	87%	75%	80%	72%	**80%**	80%
Refining Margin (3) (4) ($/bbl)	**24.70**	18.98	44.81	28.26	15.63	**28.70**	14.25
Unit Operating Expense (4) (5) ($/bbl)	**16.88**	14.90	19.13	13.59	16.88	**16.04**	12.09
Refining (6)							
Lima Refinery Throughput (Mbbls/d)	**162.6**	164.2	159.4	136.1	59.5	**157.9**	126.9
WRB Throughput (7) (Mbbls/d)	**216.4**	224.2	190.0	195.5	227.3	**206.6**	204.7
Toledo Refinery Throughput (7) (8) (Mbbls/d)	**0.2**	46.6	27.0	72.1	74.8	**36.3**	69.9

Production (Mbbls/d)	Dec. 31, 2022	Sep. 30, 2022	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2021	Dec. 31, 2022	Dec. 31, 2021
Canada							
Transportation Fuels							
Distillate	**10.5**	10.5	7.0	9.4	10.8	**9.3**	10.0
Total Transportation Fuels	**10.5**	10.5	7.0	9.4	10.8	**9.3**	10.0
Synthetic Crude Oil	**45.1**	47.7	43.5	47.8	55.3	**46.0**	54.9
Asphalt	**14.3**	15.5	9.2	15.1	15.6	**13.5**	15.5
Other	**25.3**	25.5	20.3	27.1	28.0	**24.6**	27.5
Total Refined Production	**95.2**	99.2	80.0	99.4	109.7	**93.4**	107.9
Ethanol	**5.0**	5.1	4.6	4.9	5.2	**4.9**	4.2
Total Canada	**100.2**	104.3	84.6	104.3	114.9	**98.3**	112.1
United States							
Transportation Fuels							
Gasoline	**194.4**	211.3	176.3	217.5	192.1	**200.0**	205.3
Distillate	**148.0**	173.6	144.7	147.3	131.4	**153.5**	145.3
Total Transportation Fuels	**342.4**	384.9	321.0	364.8	323.5	**353.5**	350.6
Other	**52.5**	77.8	71.5	65.8	56.4	**67.0**	68.0
Total United States	**394.9**	462.7	392.5	430.6	379.9	**420.5**	418.6
Total Downstream Production	**495.1**	567.0	477.1	534.9	494.8	**518.8**	530.7

(1) The Superior Refinery commenced commissioning in December 2022. The permitted capacity is 50.0 Mbbls/d.
(2) Based on crude oil name plate capacity. Excludes the permitted capacity of Superior.
(3) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this Supplemental.
(4) Based on crude oil throughput volumes and operating results at Wood River, Borger, Lima, Toledo and Superior refineries.
(5) Specified financial measure. See the Specified Financial Measures Advisory of this Supplemental.
(6) On April 26, 2018, the Superior refinery experienced an incident while preparing for a major turnaround and was taken out of operation.
(7) Represents Cenovus's 50 percent interest in Wood River, Borger and Toledo refinery operations.
(8) On September 20, 2022, there was an incident at the Toledo refinery. It remains shut down in a safe state.

SUPPLEMENTAL INFORMATION *(unaudited)*

Advisory

Specified Financial Measures

Certain financial measures, including non-GAAP financial measures, in this document do not have a standardized meaning prescribed by IFRS and, therefore, are considered specified financial measures. These specified financial measures may not be comparable to similar measures presented by other issuers. See the Specified Financial Measures Advisory located in our Management's Discussion and Analysis ("MD&A") for the periods ended March 31, 2022, June 30, 2022, September 30, 2022 and the annual MD&A for the year ended December 31, 2022 (available on SEDAR at sedar.com) for information incorporated by reference about these specified financial measures.

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 "anticipate", "believe", "capacity", "commit", "continue", "could", "estimate", "expect", "focus", "forecast", "future", "may", "objective", "opportunities", "option", "plan", "potential", "project", "progress", "scheduled", "seek", "strive", "target", and "will", or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: Cenovus's key priorities for 2023 and beyond, including safety and operational performance, sustainability leadership, cost leadership, financial discipline and Free Funds Flow growth and returns-focused capital allocation; the focus of our 2023 budget; cost control; maximizing, growing or enhancing shareholder value and/or returns; returning incremental capital to shareholders beyond the base dividend; allocating and paying out Excess Free Funds Flow under the capital allocation framework; deleveraging the balance sheet; a lower risk profile; opportunistic share repurchases and variable dividend distributions; safety performance and culture; the Company's targets for each of its five ESG focus areas, and long-term ambition to achieve net zero GHG emissions from operations by 2050; emissions reductions; carbon capture; methane reduction; the Company's work with Pathways Alliance to reach net zero emissions by 2050 in the oil sands; reclaiming decommissioned well sites; restoring caribou habitat; land restoration; economic self-sufficiency in Indigenous communities; spending with Indigenous-owned businesses; building homes in communities near our operations; Free Funds Flow generation, allocation, pay out and growth through commodity pricing cycles; upstream production and downstream throughput; the generation of predictable and stable cash flow; reduced risk and cash flow volatility; optimizing Cenovus's asset portfolio; funding near term cash requirements and meeting payment obligations; gains and losses from risk management; maintaining investment grade credit ratings; Net Debt targets; disciplined capital allocation; ensuring sufficient liquidity through all stages of the economic cycle; strengthening and maintaining a strong balance sheet; flexibility in both high and low commodity price environments; managing capital structure; Net Debt to Adjusted Funds Flow Ratio and Net Debt to Adjusted EBITDA Ratio; cost savings; cost structures and market optimization; interest expense; improving efficiencies to drive incremental capital, operating and general and administrative cost reductions; shortening and optimizing the value chain; reducing condensate costs associated with heavy oil transportation; maintaining the Company's capital program and sustaining the base dividend at US$45 WTI per barrel; mitigating the impact of volatility in light-heavy crude oil differentials; partially mitigating the impact of exposure to various prices for commodities and associated price differentials and refining margins; managing upstream production rates in response to pipeline capacity constraints, voluntary and mandated production curtailments and crude oil differentials; the timing of the restart of the Superior Refinery and achieving processing capacity; returning to normal processing rates at the Wood River Refinery; variable payments in respect of the Sunrise acquisition; continued use of financial instruments to mitigate exposure to various commodities (including WTI, utilized in condensate and price risk management for refining operations) and products, including associated price differentials and refining margins; drilling activity, asset integrity and emissions initiatives in the conventional segment; initial production and exploration of new fields or projects; financial resilience; adjusting capital and operating spending, drawing down on credit facilities or repaying existing debt, issuing new debt, or issuing new shares; future capital investment, including for: portfolio adjustments, the impact of inflation, maintaining safe and reliable operations, sustaining Oil Sands production, sustaining drilling programs in the conventional segment, the Superior Refinery rebuild project, the Terra Nova ALE project and White Rose project, progressing the Narrows Lake tie-back to Christina Lake, refining operations and reliability and debottlenecking in our downstream assets, increasing heavy crude oil conversion capacity; the Company's exposure to light-heavy oil differentials regardless of crude oil production; the status and timing of closing the Toledo Acquisition and ramp up of throughput; applying the Company's operating model at Sunrise and adding to production from the Sunrise Acquisition; capturing value from crude oil and natural gas production through to the sale of finished products such as transportation fuels; reinvestment in the business and diversification; the winter drilling program in the Conventional business; resuming projects, including restarting the West White Rose project and achieving first and peak oil therefrom; the return to the field of the FPSO unit for the Terra Nova ALE project and the resumption of production; first gas production from the MAC and MDK fields; drilling development wells and construction of production facilities and production therefrom; liabilities from legal proceedings; the Company's ability to partially mitigate the impact of commodity differentials; and the Company's outlook for commodities and the Canadian dollar, including the influences thereon, and the effects thereof 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 ambition, 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 December 5, 2022, and available on cenovus.com, assumes: Brent prices of US$83.00 per barrel, WTI prices of US$77.00 per barrel; WCS of US$54.50 per barrel; Differential WTI-WCS of US$22.50 per barrel; AECO natural gas prices of $4.85 per thousand cubic feet; Chicago 3-2-1 crack spread of US$26.50 per barrel; and an exchange rate of $0.75 US$/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 ambition 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 net zero ambition; 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 pursuing our ESG focus area targets, commitments and ambition 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 this 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 Annual Report unless expressly incorporated by reference herein.

ABBREVIATIONS AND DEFINITIONS

The following abbreviations and definitions have been used in this document:

Crude Oil		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
Mbbls/d	thousand barrels per day	MMcf	million cubic feet
MMbbls	million barrels	MMcf/d	million cubic feet per day
BOE	barrel of oil equivalent	Bcf	billion cubic feet
MBOE	thousand barrels of oil equivalent	MMBtu	million British thermal units
MBOE/d	thousand barrels of oil equivalent per day	GJ	gigajoule
MMBOE	million barrels of oil equivalent	AECO	Alberta Energy Company
WTI	West Texas Intermediate	NYMEX	New York Mercantile Exchange
WCS	Western Canadian Select	SAGD	steam-assisted gravity drainage
HSB	Husky Synthetic Blend		
OPEC	Organization of Petroleum Exporting Countries		
OPEC+	OPEC and a group of 10 non-OPEC members		
FPSO	Floating production storage and offloading unit		

Scope 1 emissions are direct GHG emissions from owned or operated facilities by the reporting company. This includes emissions from fuel combustion, venting, flaring, industrial processes and fugitive leaks from equipment. Cenovus accounts for emissions on a gross operatorship basis. The Company also reports its net-equity share of emissions from all of its assets.

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

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, Total Arrangement Integration Costs, 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 the MD&A.

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, 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.

	Upstream			Downstream			Total		
($ millions)	**2022**	2021 (1)	2020	**2022**	2021 (2)	2020	**2022**	2021 (1) (2)	2020
Revenues									
Gross Sales	**41,127**	27,844	9,708	**38,102**	26,258	4,815	**79,229**	54,102	14,523
Less: Royalties	**4,868**	2,454	371	**—**	—	—	**4,868**	2,454	371
	36,259	25,390	9,337	**38,102**	26,258	4,815	**74,361**	51,648	14,152
Expenses									
Purchased Product	**6,833**	4,059	1,530	**32,501**	23,111	4,429	**39,334**	27,170	5,959
Transportation and Blending	**12,194**	8,714	4,764	**—**	—	—	**12,194**	8,714	4,764
Operating	**3,789**	3,241	1,476	**3,050**	2,258	785	**6,839**	5,499	2,261
Realized (Gain) Loss on Risk Management	**1,619**	788	268	**112**	104	(21)	**1,731**	892	247
Operating Margin	**11,824**	8,588	1,299	**2,439**	785	(378)	**14,263**	9,373	921

	2022											
	Upstream				Downstream				Total			
	Three Months Ended				Three Months Ended				Three Months Ended			
($ millions)	**Q4**	Q3	Q2	Q1 (1)	**Q4**	Q3 (2)	Q2 (2)	Q1 (2)	**Q4**	Q3 (2)	Q2 (2)	Q1 (1) (2)
Revenues												
Gross Sales	**8,307**	10,238	11,685	10,897	**8,380**	10,887	10,719	8,116	**16,687**	21,125	22,404	19,013
Less: Royalties	**875**	1,226	1,582	1,185	**—**	—	—	—	**875**	1,226	1,582	1,185
	7,432	9,012	10,103	9,712	**8,380**	10,887	10,719	8,116	**15,812**	19,899	20,822	17,828
Expenses												
Purchased Product	**1,157**	2,397	1,461	1,818	**7,071**	9,694	8,919	6,817	**8,228**	12,091	10,380	8,635
Transportation and Blending	**2,962**	2,800	3,238	3,194	**—**	—	—	—	**2,962**	2,800	3,238	3,194
Operating	**955**	915	1,010	909	**759**	780	866	645	**1,714**	1,695	1,876	1,554
Realized (Gain) Loss on Risk Management	**134**	51	563	871	**(8)**	(77)	87	110	**126**	(26)	650	981
Operating Margin	**2,224**	2,849	3,831	2,920	**558**	490	847	544	**2,782**	3,339	4,678	3,464

(1) Prior period results have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.

(2) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details. There has been no impact to total downstream Operating Margin or total Operating Margin.

	2021											
	Upstream [1]				Downstream [2]				Total [1] [2]			
	Three Months Ended				Three Months Ended				Three Months Ended			
($ millions)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenues												
Gross Sales [1]	8,237	7,354	6,128	6,125	8,010	7,422	6,226	4,600	16,247	14,776	12,354	10,725
Less: Royalties	815	733	533	373	—	—	—	—	815	733	533	373
	7,422	6,621	5,595	5,752	8,010	7,422	6,226	4,600	15,432	14,043	11,821	10,352
Expenses												
Purchased Product [1]	1,198	1,074	717	1,070	7,223	6,600	5,410	3,878	8,421	7,674	6,127	4,948
Transportation and Blending [1]	2,599	2,137	2,006	1,972	—	—	—	—	2,599	2,137	2,006	1,972
Operating	865	800	791	785	689	537	515	517	1,554	1,337	1,306	1,302
Realized (Gain) Loss on Risk Management	202	168	188	230	56	17	10	21	258	185	198	251
Operating Margin	2,558	2,442	1,893	1,695	42	268	291	184	2,600	2,710	2,184	1,879

(1) *Prior period results have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.*
(2) *Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details. There has been no impact to total downstream Operating Margin or total Operating Margin.*

Operating Margin by Asset

	Three Months Ended December 31, 2022			**Year Ended December 31, 2022**		
($ millions)	**Asia Pacific**	**Atlantic**	**Offshore [1]**	**Asia Pacific**	**Atlantic**	**Offshore [2]**
Revenues						
Gross Sales	**359**	**86**	**445**	**1,442**	**578**	**2,020**
Less: Royalties	**20**	**1**	**21**	**80**	**(3)**	**77**
	339	**85**	**424**	**1,362**	**581**	**1,943**
Expenses						
Transportation and Blending	**—**	**3**	**3**	**—**	**15**	**15**
Operating	**26**	**58**	**84**	**114**	**204**	**318**
Operating Margin	**313**	**24**	**337**	**1,248**	**362**	**1,610**

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

	Three Months Ended December 31, 2021			Year Ended December 31, 2021		
($ millions)	Asia Pacific	Atlantic	Offshore [1]	Asia Pacific	Atlantic	Offshore [2]
Revenues						
Gross Sales	377	143	520	1,342	440	1,782
Less: Royalties	26	8	34	79	29	108
	351	135	486	1,263	411	1,674
Expenses						
Transportation and Blending	—	5	5	—	15	15
Operating	29	44	73	103	136	239
Operating Margin	322	86	408	1,160	260	1,420

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

Total Arrangement Integration Costs

Total Arrangement Integration Costs is a non-GAAP financial measure representing costs incurred as a result of the Arrangement, excluding share issuance costs.

	Year Ended December 31,	
($ millions)	**2022**	2021
Integration Costs [1]	**90**	349
Capitalized Integration Costs [2]	**5**	53
Total Arrangement Integration Costs	**95**	402

(1) See Note 8 of the Consolidated Financial Statements.
(2) Included in capital expenditures on the Consolidated Statements of Cash Flows.

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, inventories (excluding non-cash inventory write-downs and reversals), income tax receivable, 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. Excess Free Funds Flow was a new metric as of June 30, 2022.

	2022				2021			
($ millions)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Cash From (Used in) Operating Activities	**2,970**	4,089	2,979	1,365	2,184	2,138	1,369	228
(Add) Deduct:								
Settlement of Decommissioning Liabilities	**(49)**	(55)	(27)	(19)	(35)	(38)	(18)	(11)
Net Change in Non-Cash Working Capital	**673**	1,193	(92)	(1,199)	271	(166)	(430)	(902)
Adjusted Funds Flow	**2,346**	2,951	3,098	2,583	1,948	2,342	1,817	1,141
Capital Investment	**1,274**	866	822	746	835	647	534	547
Free Funds Flow	**1,072**	2,085	2,276	1,837	1,113	1,695	1,283	594
Add (Deduct):								
Base Dividends Paid on Common Shares	**(201)**	(205)	(207)	(69)	(70)	(35)	(36)	(35)
Dividends Paid on Preferred Shares	**—**	(9)	(8)	(9)	(8)	(9)	(8)	(9)
Settlement of Decommissioning Liabilities	**(49)**	(55)	(27)	(19)	(35)	(38)	(18)	(11)
Principal Repayment of Leases	**(74)**	(78)	(75)	(75)	(78)	(70)	(77)	(75)
Acquisitions, Net of Cash Acquired	**(7)**	(389)	(1)	—	—	—	—	(7)
Proceeds From Divestitures	**45**	407	112	950	247	83	100	5
Payment on Divestiture of Assets	**—**	—	(50)	—	—	—	—	—
Excess Free Funds Flow	**786**	1,756	2,020	2,615	1,169	1,626	1,244	462

($ millions)	Year Ended December 31, 2022	2021	2020
Cash From (Used in) Operating Activities	**11,403**	5,919	273
(Add) Deduct:			
Settlement of Decommissioning Liabilities	**(150)**	(102)	(42)
Net Change in Non-Cash Working Capital	**575**	(1,227)	198
Adjusted Funds Flow	**10,978**	7,248	117
Capital Investment	**3,708**	2,563	841
Free Funds Flow	**7,270**	4,685	(724)

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 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 throughput in our downstream operations.

Canadian Manufacturing

Three Months Ended December 31, 2022

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

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

Three Months Ended September 30, 2022 [3][4]

($ millions)	Basis of Refining Margin Calculation: Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Manufacturing [2]
Revenues	999	387	1,386	782	2,168
Purchased Product	747	286	1,033	714	1,747
Gross Margin	252	101	353	68	421

Operating Statistics	Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
Heavy Crude Oil Throughput (Mbbls/d)	71.3	27.2	98.5
Refining Margin ($/bbl)	38.33	40.33	38.88

(1) Includes ethanol operations, crude-by-rail operations and the commercial fuels business.
(2) These amounts, excluding gross margin, are found in Note 1 of the interim Consolidated Financial Statements.
(3) Comparative information has been represented for the Canadian Manufacturing refining margins to include marketing activities.
(4) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details. There has been no impact to total downstream Operating Margin or total Operating Margin.

	Three Months Ended June 30, 2022 [1]				
	Basis of Refining Margin Calculation				
($ millions)	**Lloydminster Upgrader**	**Lloydminster Refinery**	**Lloydminster Upgrader and Lloydminster Refinery Total**	**Other [2]**	**Total Canadian Manufacturing [3] [4]**
Revenues	1,162	243	1,405	840	2,245
Purchased Product	1,012	210	1,222	760	1,982
Gross Margin	150	33	183	80	263

	Operating Statistics		
	Lloydminster Upgrader	**Lloydminster Refinery**	**Lloydminster Upgrader and Lloydminster Refinery Total**
Heavy Crude Oil Throughput (Mbbls/d)	64.6	16.3	80.9
Refining Margin ($/bbl)	25.54	22.22	24.87

	Three Months Ended March 31, 2022 [1]				
	Basis of Refining Margin Calculation				
($ millions)	**Lloydminster Upgrader**	**Lloydminster Refinery**	**Lloydminster Upgrader and Lloydminster Refinery Total**	**Other [2]**	**Total Canadian Manufacturing [3] [4]**
Revenues	756	186	942	665	1,607
Purchased Product	585	143	728	605	1,333
Gross Margin	171	43	214	60	274

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

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

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

(1) Comparative information has been represented for the Canadian Manufacturing refining margins to include marketing activities.
(2) Includes ethanol operations, crude-by-rail operations and the commercial fuels business.
(3) These amounts, excluding gross margin, are found in Note 1 of the interim Consolidated Financial Statements.
(4) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details. There has been no impact to total downstream Operating Margin or total Operating Margin.

($ millions)	Three Months Ended December 31, 2021 [1] Basis of Refining Margin Calculation: Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [2]	Total Canadian Manufacturing [3] [4]
Revenues	1,044	205	1,249	607	1,856
Purchased Product	887	172	1,059	529	1,588
Gross Margin	157	33	190	78	268

	Operating Statistics: Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
Heavy Crude Oil Throughput (Mbbls/d)	80.4	27.9	108.3
Refining Margin ($/bbl)	21.26	12.77	19.07

($ millions)	Year Ended December 31, 2021 [1] Basis of Refining Margin Calculation: Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total	Other [2]	Total Canadian Manufacturing [3] [4]
Revenues	3,245	816	4,061	2,154	6,215
Purchased Product	2,698	659	3,357	1,799	5,156
Gross Margin	547	157	704	355	1,059

	Operating Statistics: Lloydminster Upgrader	Lloydminster Refinery	Lloydminster Upgrader and Lloydminster Refinery Total
Heavy Crude Oil Throughput (Mbbls/d)	79.0	27.5	106.5
Refining Margin ($/bbl)	18.96	15.60	18.09

(1) Comparative information has been represented for the Canadian Manufacturing refining margins to include marketing activities.
(2) Includes ethanol operations, crude-by-rail operations and the commercial fuels business.
(3) These amounts, excluding gross margin, are found in Note 1 of the interim Consolidated Financial Statements.
(4) Prior period results have been re-presented. In September 2022, the Company divested the majority of the retail fuels business. The Retail segment has been aggregated with the Canadian Manufacturing segment. See Note 3 of the Consolidated Financial Statements for further details. There has been no impact to total downstream Operating Margin or total Operating Margin.

U.S. Manufacturing

($ millions)	Three Months Ended December 31, 2022	2021
Revenues [(1)]	**6,608**	6,154
Purchased Product [(1)]	**5,747**	5,635
Gross Margin	**861**	519
Crude Oil Throughput (Mbbls/d)	**379.2**	361.6
Refining Margin ($/bbl)	**24.70**	15.63

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

($ millions)	Year Ended December 31, 2022	2021	2020
Revenues [(1)]	**30,310**	20,043	4,733
Purchased Product [(1)]	**26,112**	17,955	4,429
Gross Margin	**4,198**	2,088	304
Crude Oil Throughput (Mbbls/d)	**400.8**	401.5	185.9
Refining Margin ($/bbl)	**28.70**	14.25	4.47

(1) Found in Note 1 of the 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 costs, 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 December 31, 2022 ($ millions)	Total Upstream (1)	Condensate	Third-Party Sourced	Internal Consumption (2)	Equity Adjustment (3)	Other (4)	Total Upstream
Gross Sales	8,307	(2,415)	(1,063)	(349)	77	(123)	4,434
Royalties	875	—	—	—	27	(1)	901
Purchased Product	1,157	—	(1,063)	—	—	(94)	—
Transportation and Blending	2,962	(2,415)	—	—	—	(4)	543
Operating	955	—	—	(349)	15	(11)	610
Netback	2,358	—	—	—	35	(13)	2,380
Realized (Gain) Loss on Risk Management	134	—	—	—	—	—	134
Operating Margin	2,224	—	—	—	35	(13)	2,246

		Adjustments					Basis of Netback Calculation
Three Months Ended December 31, 2021 ($ millions)	Total Upstream (1)	Condensate	Third-Party Sourced	Internal Consumption (2)	Equity Adjustment (3)	Other (4)	Total Upstream
Gross Sales (5)	8,237	(2,201)	(1,079)	(241)	62	(146)	4,632
Royalties	815	—	—	—	29	—	844
Purchased Product (5)	1,198	—	(1,079)	—	—	(119)	—
Transportation and Blending	2,599	(2,201)	—	—	—	—	398
Operating	865	—	(8)	(241)	7	(3)	620
Netback	2,760	—	8	—	26	(24)	2,770
Realized (Gain) Loss on Risk Management	202	—	—	—	—	—	202
Operating Margin	2,558	—	8	—	26	(24)	2,568

(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.
(5) Prior period results have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.

Year Ended December 31, 2022 ($ millions)	Total Upstream (1)	Adjustments Condensate	Third-Party Sourced	Internal Consumption (2)	Equity Adjustment (3)	Other (4)	Basis of Netback Calculation Total Upstream
Gross Sales	41,127	(10,307)	(6,524)	(1,170)	271	(429)	22,968
Royalties	4,868	—	—	—	116	(12)	4,972
Purchased Product	6,833	—	(6,524)	—	—	(309)	—
Transportation and Blending	12,194	(10,307)	—	—	—	(39)	1,848
Operating	3,789	—	—	(1,170)	36	(39)	2,616
Netback	13,443	—	—	—	119	(30)	13,532
Realized (Gain) Loss on Risk Management	1,619	—	(8)	—	—	—	1,611
Operating Margin	11,824	—	8	—	119	(30)	11,921

Year Ended December 31, 2021 ($ millions)	Total Upstream (1)	Adjustments Condensate	Third-Party Sourced	Internal Consumption (2)	Equity Adjustment (3)	Other (4)	Basis of Netback Calculation Total Upstream
Gross Sales (5)	27,844	(7,095)	(3,761)	(710)	224	(390)	16,112
Royalties	2,454	—	—	—	52	—	2,506
Purchased Product (5)	4,059	—	(3,761)	—	—	(298)	—
Transportation and Blending	8,714	(7,095)	—	—	—	—	1,619
Operating	3,241	—	(8)	(710)	25	(36)	2,512
Netback	9,376	—	8	—	147	(56)	9,475
Realized (Gain) Loss on Risk Management	788	—	(2)	—	—	—	786
Operating Margin	8,588	—	10	—	147	(56)	8,689

Year Ended December 31, 2020 ($ millions)	Total Upstream (1)	Adjustments Condensate	Third-Party Sourced	Internal Consumption (2)	Equity Adjustment (3)	Other (4)	Basis of Netback Calculation Total Upstream
Gross Sales (5)	9,708	(3,452)	(1,559)	—	(295)	(58)	4,344
Royalties	371	—	—	(1)	—	—	370
Purchased Product (5)	1,530	—	(1,559)	—	—	29	—
Transportation and Blending	4,764	(3,452)	—	1	—	—	1,313
Operating	1,476	—	—	—	(295)	(72)	1,109
Netback	1,567	—	—	—	—	(15)	1,552
Realized (Gain) Loss on Risk Management	268	—	—	—	—	—	268
Operating Margin	1,299	—	—	—	—	(15)	1,284

(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.
(5) Prior period results have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.

Oil Sands

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

	Basis of Netback Calculation	Adjustments			
Three Months Ended December 31, 2022 ($ millions)	Total Oil Sands	Condensate	Third-party Sourced	Other [2]	Total Oil Sands [3]
Gross Sales	3,706	2,415	500	110	6,731
Royalties	784	—	—	—	784
Purchased Product	—	—	500	94	594
Transportation and Blending	493	2,415	—	14	2,922
Operating	735	—	—	(2)	733
Netback	1,694	—	—	4	1,698
Realized (Gain) Loss on Risk Management	59	—	—	—	59
Operating Margin	1,635	—	—	4	1,639

	Basis of Netback Calculation						
Three Months Ended December 31, 2021 ($ millions)	Foster Creek	Christina Lake	Sunrise	Other Oil Sands [1]	Total Bitumen and Heavy Oil	Natural Gas	Total Oil Sands
Gross Sales	1,304	1,441	189	903	3,837	4	3,841
Royalties	280	345	7	102	734	—	734
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	166	140	28	42	376	—	376
Operating	184	194	39	230	647	6	653
Netback	674	762	115	529	2,080	(2)	2,078
Realized (Gain) Loss on Risk Management							202
Operating Margin							1,876

	Basis of Netback Calculation	Adjustments			
Three Months Ended December 31, 2021 ($ millions)	Total Oil Sands	Condensate	Third-party Sourced	Other [2]	Total Oil Sands [3]
Gross Sales [4]	3,841	2,201	537	138	6,717
Royalties	734	—	—	—	734
Purchased Product [4]	—	—	537	119	656
Transportation and Blending	376	2,201	—	—	2,577
Operating	653	—	—	5	658
Netback	2,078	—	—	14	2,092
Realized (Gain) Loss on Risk Management	202	—	—	—	202
Operating Margin	1,876	—	—	14	1,890

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

(1) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.
(2) Other includes construction, transportation and blending margin.
(3) These amounts, excluding netback, are found in Note 1 of the interim Consolidated Financial Statements.
(4) Prior period results have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.

Year Ended December 31, 2022 ($ millions)	Basis of Netback Calculation Total Oil Sands	Adjustments Condensate	 Third-party Sourced	 Other [2]	Total Oil Sands [3]
Gross Sales	19,609	10,307	4,501	358	34,775
Royalties	4,482	—	—	11	4,493
Purchased Product	—	—	4,501	309	4,810
Transportation and Blending	1,686	10,307	—	43	12,036
Operating	2,941	—	—	(11)	2,930
Netback	10,500	—	—	6	10,506
Realized (Gain) Loss on Risk Management	1,527	—	—	—	1,527
Operating Margin	8,973	—	—	6	8,979

Year Ended December 31, 2021 ($ millions)	Basis of Netback Calculation Foster Creek	 Christina Lake	 Sunrise	 Other Oil Sands [1]	 Total Bitumen and Heavy Oil	 Natural Gas	 Total Oil Sands
Gross Sales	4,341	5,115	616	3,212	13,284	13	13,297
Royalties	767	1,078	20	330	2,195	1	2,196
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	686	526	111	207	1,530	—	1,530
Operating	701	700	157	858	2,416	21	2,437
Netback	2,187	2,811	328	1,817	7,143	(9)	7,134
Realized (Gain) Loss on Risk Management							786
Operating Margin							6,348

Year Ended December 31, 2021 ($ millions)	Basis of Netback Calculation Total Oil Sands	Adjustments Condensate	 Third-party Sourced	 Other [2]	Total Oil Sands [3]
Gross Sales [4]	13,297	7,095	2,106	329	22,827
Royalties	2,196	—	—	—	2,196
Purchased Product [4]	—	—	2,106	298	2,404
Transportation and Blending	1,530	7,095	—	—	8,625
Operating	2,437	—	—	14	2,451
Netback	7,134	—	—	17	7,151
Realized (Gain) Loss on Risk Management	786	—	—	—	786
Operating Margin	6,348	—	—	17	6,365

Year Ended December 31, 2020 ($ millions)	Basis of Netback Calculation Foster Creek	 Christina Lake	 Total Oil Sands
Gross Sales	1,859	2,194	4,053
Royalties	95	235	330
Purchased Product	—	—	—
Transportation and Blending	667	565	1,232
Operating	558	551	1,109
Netback	539	843	1,382
Realized (Gain) Loss on Risk Management			268
Operating Margin			1,114

Year Ended December 31, 2020 ($ millions)	Basis of Netback Calculation Total Oil Sands	Adjustments Condensate	 Third-party Sourced	 Inventory Write-down [5]	 Other [2]	Total Oil Sands [3]
Gross Sales [4]	4,053	3,452	1,290	—	9	8,804
Royalties	330	—	—	1	—	331
Purchased Product [4]	—	—	1,290	—	(28)	1,262
Transportation and Blending	1,232	3,452	—	(1)	—	4,683
Operating	1,109	—	—	—	47	1,156
Netback	1,382	—	—	—	(10)	1,372
Realized (Gain) Loss on Risk Management	268	—	—	—	—	268
Operating Margin	1,114	—	—	—	(10)	1,104

(1) Includes Tucker, Lloydminster thermal and Lloydminster conventional heavy oil assets. The Tucker asset was sold on January 31, 2022.
(2) Other includes construction, transportation and blending margin.
(3) These amounts, excluding netback, are found in Note 1 of the interim Consolidated Financial Statements.
(4) Prior period results have been adjusted to more appropriately reflect the cost of blending. See Note 3 of the Consolidated Financial Statements for further details.
(5) Netbacks do not reflect non-cash write-downs or reversals of product inventory until it is realized when the product is sold. These amounts are net of inventory write-down reversals.

Conventional

Three Months Ended December 31, 2022 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	555	563	13	1,131
Royalties	69	—	1	70
Purchased Product	—	563	—	563
Transportation and Blending	47	—	(10)	37
Operating	135	—	3	138
Netback	304	—	19	323
Realized (Gain) Loss on Risk Management	75	—	—	75
Operating Margin	229	—	19	248

Three Months Ended December 31, 2021 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	450	542	8	1,000
Royalties	47	—	—	47
Purchased Product	—	542	—	542
Transportation and Blending	17	—	—	17
Operating	128	8	(2)	134
Netback	258	(8)	10	260
Realized (Gain) Loss on Risk Management	—	—	—	—
Operating Margin	258	(8)	10	260

Year Ended December 31, 2022 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	2,238	2,023	71	4,332
Royalties	297	—	1	298
Purchased Product	—	2,023	—	2,023
Transportation and Blending	147	—	(4)	143
Operating	520	—	21	541
Netback	1,274	—	53	1,327
Realized (Gain) Loss on Risk Management	84	8	—	92
Operating Margin	1,190	(8)	53	1,235

Year Ended December 31, 2021 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	1,519	1,655	61	3,235
Royalties	150	—	—	150
Purchased Product	—	1,655	—	1,655
Transportation and Blending	74	—	—	74
Operating	521	8	22	551
Netback	774	(8)	39	805
Realized (Gain) Loss on Risk Management	—	2	—	2
Operating Margin	774	(10)	39	803

Year Ended December 31, 2020 ($ millions)	Basis of Netback Calculation Conventional	Adjustments Third-party Sourced	Other [1]	Conventional [2]
Gross Sales	586	269	49	904
Royalties	40	—	—	40
Purchased Product	—	269	(1)	268
Transportation and Blending	81	—	—	81
Operating	295	—	25	320
Netback	170	—	25	195
Realized (Gain) Loss on Risk Management	—	—	—	—
Operating Margin	170	—	25	195

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

Offshore

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

Three Months Ended December 31, 2021 ($ millions)	Basis of Netback Calculation					Adjustment	
	China	Indonesia (1)	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment (1)	Total Offshore (3)
Gross Sales	377	62	439	143	582	(62)	520
Royalties	26	29	55	8	63	(29)	34
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	5	5	—	5
Operating	23	12	35	45	80	(7)	73
Netback	328	21	349	85	434	(26)	408
Realized (Gain) Loss on Risk Management					—	—	—
Operating Margin					434	(26)	408

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

Year Ended December 31, 2021 ($ millions)	Basis of Netback Calculation					Adjustment	
	China	Indonesia (1)	Asia Pacific	Atlantic	Total Offshore	Equity Adjustment (1)	Total Offshore (2)
Gross Sales	1,342	224	1,566	440	2,006	(224)	1,782
Royalties	79	52	131	29	160	(52)	108
Purchased Product	—	—	—	—	—	—	—
Transportation and Blending	—	—	—	15	15	—	15
Operating	94	33	127	137	264	(25)	239
Netback	1,169	139	1,308	259	1,567	(147)	1,420
Realized (Gain) Loss on Risk Management					—	—	—
Operating Margin					1,567	(147)	1,420

(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 December 31,		Year Ended December 31,		
(MBOE/d)	**2022**	2021	**2022**	2021	2020
Oil Sands					
Foster Creek	**184.7**	194.5	**189.4**	178.8	164.9
Christina Lake	**246.5**	239.1	**247.5**	232.7	221.7
Sunrise [(2)]	**42.0**	29.9	**30.2**	25.2	—
Other Oil Sands	**118.5**	141.2	**118.7**	143.2	—
Total Oil Sands [(2)]	**591.7**	604.7	**585.8**	579.9	386.6
Conventional	**125.5**	125.3	**127.2**	133.4	89.8
Sales before Internal Consumption	**717.2**	730.0	**713.0**	713.3	476.4
Less: Internal Consumption [(3)]	**(93.4)**	(88.8)	**(86.6)**	(86.0)	(55.9)
Sales after Internal Consumption	**623.8**	641.2	**626.4**	627.3	420.5
Offshore					
Asia Pacific - China	**47.1**	52.7	**48.2**	50.8	—
Asia Pacific - Indonesia	**12.8**	9.8	**10.5**	9.5	—
Asia Pacific - Total	**59.9**	62.5	**58.7**	60.3	—
Atlantic	**7.3**	15.0	**11.3**	13.2	—
Total Offshore	**67.2**	77.5	**70.0**	73.5	—
Total Sales	**691.0**	718.7	**696.4**	700.8	420.5

(1) Presented on dry bitumen basis.
(2) Sunrise sales volumes have been re-presented to reflect a change in classification of marketing activities for the first and second quarters of 2021.
(3) Less natural gas volumes used for internal consumption by the Oil Sands segment.

Adjustments to the Consolidated Statements of Earnings (Loss) and Segmented Disclosures

Certain comparative information presented in the Consolidated Statements of Earnings (Loss) within the Oil Sands, Canadian Manufacturing, historical Retail and Corporate and Eliminations segments were revised.

During the three months ended June 30, 2022, the Company made adjustments to more appropriately reflect the cost of blending at the Lloydminster thermal and Lloydminster conventional heavy oil assets, which resulted in a reclassification of costs between purchased product and transportation and blending. An associated elimination entry was recorded in the Corporate and Eliminations segment to re-present the change in the value of condensate that was extracted at the Canadian Manufacturing operations and sold back to the Oil Sands segment. As a result, purchased product decreased and transportation and blending increased, with no impact to net earnings (loss), segment income (loss), financial position or cash flows. Refer to the interim Consolidated Financial Statements for the periods ended June 30, 2022, for further details.

In September 2022, the Company completed the divestiture of the majority of the retail fuels business. As a result, Management elected to aggregate the remaining commercial fuels business and the historical retail fuels business into the Canadian Manufacturing segment. Comparative periods have been re-presented to reflect this change, with no impact to net earnings (loss), financial position or cash flows. Refer to the Consolidated Financial Statements for further details.

The following tables reconcile the amounts previously reported in the interim Consolidated Statements of Earnings (Loss) for the respective period or the December 31, 2021 Consolidated Financial Statements, to the corresponding revised amounts:

	Three Months Ended March 31, 2022			Three Months Ended June 30, 2022			Three Months Ended September 30, 2022		
($ millions)	Reported	Revision	**Revised**	Reported	Revision	**Revised**	Reported	Revision	**Revised**
Oil Sands Segment									
Purchased Product	1,483	(271)	**1,212**						
Transportation and Blending	2,885	271	**3,156**						
	4,368	—	**4,368**						
Canadian Manufacturing Segment									
Gross Sales	1,044	563	**1,607**	1,521	724	**2,245**	1,478	690	**2,168**
Purchased Product	806	529	**1,335**	1,294	686	**1,980**	1,095	655	**1,750**
Operating Expenses	124	27	**151**	180	31	**211**	134	38	**172**
Depreciation, Depletion and Amortization	42	8	**50**	64	8	**72**	37	5	**42**
	72	(1)	**71**	(17)	(1)	**(18)**	212	(8)	**204**
Retail Segment									
Gross Sales	694	(694)	**—**	849	(849)	**—**	881	(881)	**—**
Purchased Product	660	(660)	**—**	811	(811)	**—**	846	(846)	**—**
Operating Expenses	27	(27)	**—**	31	(31)	**—**	38	(38)	**—**
Depreciation, Depletion and Amortization	8	(8)	**—**	8	(8)	**—**	5	(5)	**—**
	(1)	1	**—**	(1)	1	**—**	(8)	8	**—**
Corporate and Eliminations Segment									
Gross Sales	(1,761)	131	**(1,630)**	(1,782)	125	**(1,657)**	(2,619)	191	**(2,428)**
Purchased Product	(1,497)	346	**(1,151)**	(1,111)	125	**(986)**	(2,267)	191	**(2,076)**
Transportation and Blending	(6)	(215)	**(221)**	(188)	—	**(188)**	(119)	—	**(119)**
	(258)	—	**(258)**	(483)	—	**(483)**	(233)	—	**(233)**
Consolidated									
Gross Sales	17,383	—	**17,383**	20,747	—	**20,747**	18,697	—	**18,697**
Purchased Product	7,538	(56)	**7,482**	9,396	—	**9,396**	10,012	—	**10,012**
Transportation and Blending	2,919	56	**2,975**	3,048	—	**3,048**	2,684	—	**2,684**
Operating Expenses	1,287	—	**1,287**	1,481	—	**1,481**	1,439	—	**1,439**
Depreciation, Depletion and Amortization	1,030	—	**1,030**	1,132	—	**1,132**	1,047	—	**1,047**
	4,609	—	**4,609**	5,690	—	**5,690**	3,515	—	**3,515**

($ millions)	Three Months Ended March 31, 2021			Three Months Ended June 30, 2021			Three Months Ended September 30, 2021			Three Months Ended December 31, 2021			Year Ended December 31, 2021		
	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**	Previously Reported	Revision	**Revised**
Oil Sands Segment															
Purchased Product	861	(172)	**689**	634	(204)	**430**	825	(196)	**629**	868	(212)	**656**	3,188	(784)	**2,404**
Transportation and Blending	1,778	172	**1,950**	1,780	204	**1,984**	1,918	196	**2,114**	2,365	212	**2,577**	7,841	784	**8,625**
	2,639	—	**2,639**	2,414	—	**2,414**	2,743	—	**2,743**	3,233	—	**3,233**	11,029	—	**11,029**
Canadian Manufacturing Segment															
Gross Sales	806	357	**1,163**	1,088	409	**1,497**	1,215	484	**1,699**	1,363	493	**1,856**	4,472	1,743	**6,215**
Purchased Product	631	327	**958**	807	374	**1,181**	986	443	**1,429**	1,128	460	**1,588**	3,552	1,604	**5,156**
Operating Expenses	93	19	**112**	92	29	**121**	99	25	**124**	104	25	**129**	388	98	**486**
Depreciation, Depletion and Amortization	43	12	**55**	43	13	**56**	41	11	**52**	40	23	**63**	167	59	**226**
	39	(1)	**38**	146	(7)	**139**	89	5	**94**	91	(15)	**76**	365	(18)	**347**
Retail Segment															
Gross Sales	447	(447)	**—**	501	(501)	**—**	592	(592)	**—**	618	(618)	**—**	2,158	(2,158)	**—**
Purchased Product	417	(417)	**—**	466	(466)	**—**	551	(551)	**—**	585	(585)	**—**	2,019	(2,019)	**—**
Operating Expenses	19	(19)	**—**	29	(29)	**—**	25	(25)	**—**	25	(25)	**—**	98	(98)	**—**
Depreciation, Depletion and Amortization	12	(12)	**—**	13	(13)	**—**	11	(11)	**—**	23	(23)	**—**	59	(59)	**—**
	(1)	1	**—**	(7)	7	**—**	5	(5)	**—**	(15)	15	**—**	(18)	18	**—**
Corporate and Eliminations Segment															
Gross Sales	(1,149)	90	**(1,059)**	(1,276)	92	**(1,184)**	(1,450)	108	**(1,342)**	(1,831)	125	**(1,706)**	(5,706)	415	**(5,291)**
Purchased Product	(973)	228	**(745)**	(1,110)	238	**(872)**	(1,244)	261	**(983)**	(1,561)	317	**(1,244)**	(4,888)	1,044	**(3,844)**
Transportation and Blending	(15)	(138)	**(153)**	(6)	(146)	**(152)**	(18)	(153)	**(171)**	(8)	(192)	**(200)**	(47)	(629)	**(676)**
	(161)	—	**(161)**	(160)	—	**(160)**	(188)	—	**(188)**	(262)	—	**(262)**	(771)	—	**(771)**
Consolidated															
Gross Sales	9,666	—	**9,666**	11,170	—	**11,170**	13,434	—	**13,434**	14,541	—	**14,541**	48,811	—	**48,811**
Purchased Product	4,237	(34)	**4,203**	5,313	(58)	**5,255**	6,734	(43)	**6,691**	7,197	(20)	**7,177**	23,481	(155)	**23,326**
Transportation and Blending	1,785	34	**1,819**	1,796	58	**1,854**	1,923	43	**1,966**	2,379	20	**2,399**	7,883	155	**8,038**
Operating Expenses	1,134	—	**1,134**	1,144	—	**1,144**	1,150	—	**1,150**	1,288	—	**1,288**	4,716	—	**4,716**
Depreciation, Depletion and Amortization	1,045	—	**1,045**	1,036	—	**1,036**	1,153	—	**1,153**	2,652	—	**2,652**	5,886	—	**5,886**
	1,465	—	**1,465**	1,881	—	**1,881**	2,474	—	**2,474**	1,025	—	**1,025**	6,845	—	**6,845**

INFORMATION FOR SHAREHOLDERS

ANNUAL MEETING

The meeting will be held virtually only. This allows a broader base of shareholders to participate regardless of their location. Holders of Cenovus common shares are invited to attend the virtual Annual Meeting of Shareholders to be held on Wednesday, April 26, 2023 at 11:00 a.m. MT via live webcast accessible online at **https://web.lumiagm.com/422837892**.
Please see our Management Information Circular available on **cenovus.com** for additional information.

REGISTRAR AND TRANSFER AGENT

Computershare Investor Services Inc.
8th Floor, 100 University Avenue
Toronto, Ontario M5J 2Y1 Canada
https://www.cenovus.com/Investors/Shareholder-information
Shareholder inquiries by phone:
North America 1.866.332.8898 (English and French)
Outside North America 1.514.982.8717 (English and French)

SHAREHOLDER ACCOUNT MATTERS

For information regarding your shareholdings or to change your address, transfer shares, eliminate duplicate mailings, directly deposit dividends, etc., please contact Computershare Investor Services Inc. If your shares are held by a broker, please contact your broker.

STOCK EXCHANGES

Cenovus common shares trade on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) under the symbol CVE. Cenovus warrants trade on the TSX and the NYSE under the symbols TSX: CVE.WT and NYSE: CVE.WS. Cenovus preferred shares Series 1, Series 2, Series 3, Series 5 and Series 7 trade on the TSX under the symbols CVE.PR.A, CVE.PR.B, CVE.PR.C, CVE.PR.E and CVE.PR.G.

ANNUAL INFORMATION FORM/FORM 40-F

Our Annual Information Form is filed with the Canadian Securities Administrators in Canada on SEDAR at **sedar.com** and with the U.S. Securities and Exchange Commission under the Multi-Jurisdictional Disclosure System as an Annual Report on Form 40-F on EDGAR at **sec.gov**.

NYSE CORPORATE GOVERNANCE STANDARDS

As a Canadian company listed on the NYSE, we are not required to comply with most of the NYSE corporate governance standards and instead may comply with Canadian corporate governance requirements. We are, however, required to disclose the significant differences between our corporate governance practices and those required to be followed by U.S. domestic companies under the NYSE corporate governance standards. Except as summarized on **https://www.cenovus.com/Our-company/Governance**, we are in compliance with the NYSE corporate governance standards in all significant respects.

INVESTOR RELATIONS

Please visit the Investors section at **cenovus.com** for investor information.

Investor inquiries should be directed to:
403.766.7711, **investor.relations@cenovus.com**

Media inquiries should be directed to:
403.766.7751, **media.relations@cenovus.com**

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CENOVUS'S LEADERSHIP TEAM

(as at March 1, 2023)

Alex Pourbaix, President & Chief Executive Officer
Susan Anderson, SVP, People Services
Keith Chiasson, EVP, Downstream
Andrew Dahlin, EVP, Corporate & Operations Services
Rhona DelFrari, Chief Sustainability Officer & EVP, Stakeholder Engagement
Jeff Hart, EVP & Chief Financial Officer
Jon McKenzie, EVP & Chief Operating Officer
Gary Molnar, SVP, Legal, General Counsel & Corporate Secretary
Norrie Ramsay, EVP, Upstream – Thermal, Major Projects & Offshore
Kam Sandhar, EVP, Strategy & Corporate Development
Drew Zieglgansberger, EVP, Natural Gas & Technical Services

CENOVUS'S BOARD OF DIRECTORS

(as at March 1, 2023)

Keith A. MacPhail, Board Chair, Calgary, Alberta [2,6]
Keith M. Casey, San Antonio, Texas [3,4]
Canning K.N. Fok, Hong Kong Special Administrative Region
Jane E. Kinney, Toronto, Ontario [1,4]
Harold N. Kvisle, Calgary, Alberta [2,3]
Eva L. Kwok, Vancouver, British Columbia [2,3]
Melanie A. Little, Alpharetta, Georgia [3,4]
Richard J. Marcogliese, Alamo, California [1,4]
Claude Mongeau, Montréal, Québec [1,4]
Alex J. Pourbaix, Calgary, Alberta [5]
Wayne E. Shaw, Toronto, Ontario [1,4]
Frank J. Sixt, Hong Kong Special Administrative Region [2]
Rhonda I. Zygocki, Friday Harbor, Washington [2,3]

(1) Member of the Audit Committee
(2) Member of the Governance Committee
(3) Member of the Human Resources and Compensation ("HRC") Committee
(4) Member of the Safety, Sustainability and Reserves ("SSR") Committee
(5) As an officer and a non-independent director, Mr. Pourbaix is not a member of any of the committees of Cenovus's Board
(6) An ex officio non-voting member of the Audit Committee, HRC Committee and SSR Committee

CENOVUS ENERGY INC.

Cenovus Energy Inc. is an integrated energy company with oil and natural gas production operations in Canada and the Asia Pacific region, and upgrading, refining and marketing operations in Canada and the United States. The company is focused on managing its assets in a safe, innovative and cost-efficient manner, integrating environmental, social and governance considerations into its business plans. Cenovus common shares and warrants are listed on the Toronto and New York stock exchanges, and the company's preferred shares are listed on the Toronto Stock Exchange.

For more information, visit **cenovus.com**.

cenovus ENERGY

cenovus.com

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