2023 Annual Report

STRATHCONA
RESOURCES LTD

About Strathcona

Strathcona is one of North America's fastest growing oil and gas producers engaged in the acquisition, exploration, development and production of petroleum and natural gas reserves across three core areas: Cold Lake Thermal, Lloydminster Heavy Oil and Montney. Strathcona's crude oil and natural gas operations are principally located in Western Canada, in the provinces of British Columbia, Alberta and Saskatchewan. Strathcona's products are sold in Canada or transported to sales points in the US via rail or pipeline. Strathcona's common shares are listed on the Toronto Stock Exchange under the symbol SCR.

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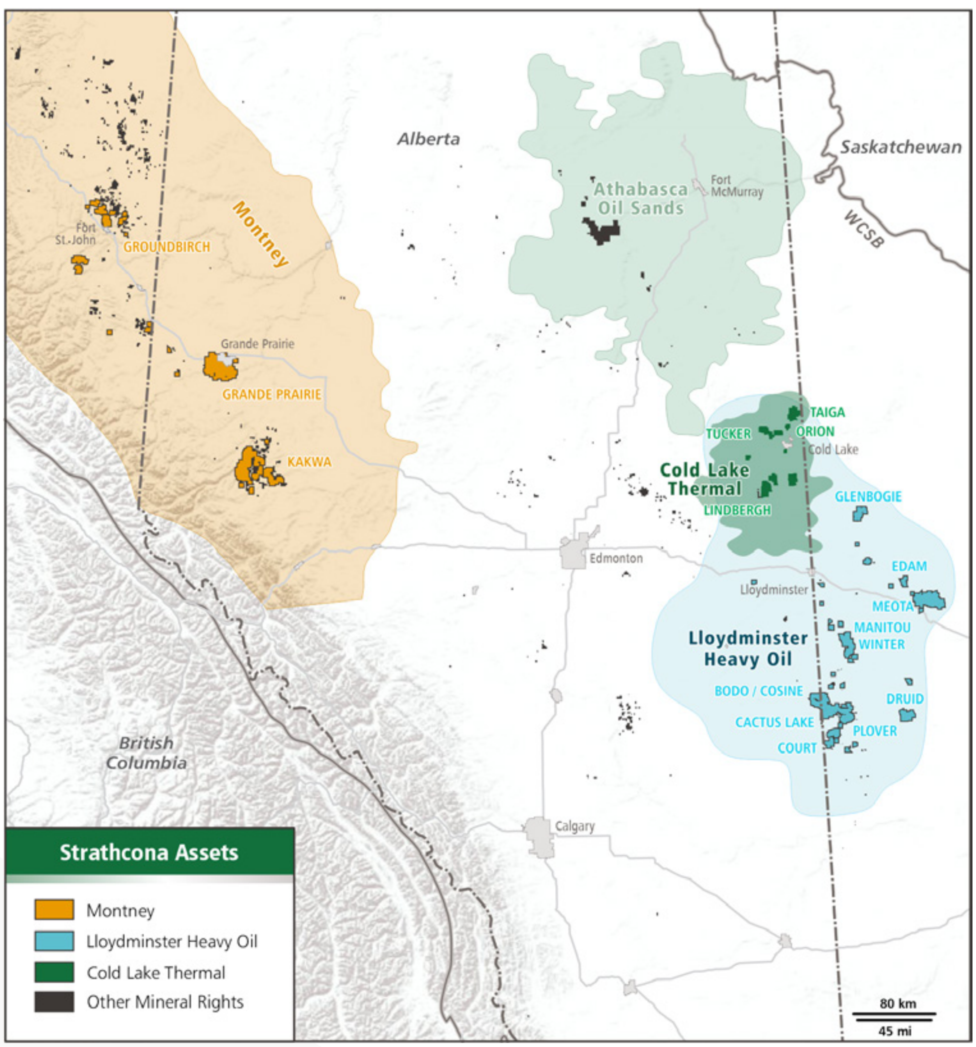

2023 Highlights

SCR.TO

Strathcona became a publicly traded company
Following a successful combination with Pipestone Energy Corp.

~185,000

barrels of oil equivalent per day
Canada's fifth largest liquids-weighted producer

0.49

total recordable injury frequency
Best-in-industry performance

38.5 years

2P reserve life index
Uniquely positioned for growth

Message to Shareholders

In 2023, we opened another new and exciting chapter for Strathcona.

We successfully combined with Pipestone Energy Corp., making us a publicly traded company and Canada's fifth largest liquids-weighted producer with approximately 185,000 barrels of oil equivalent per day – a noteworthy achievement considering the Waterous Energy Fund's initial investment seven years ago was in a company that produced just 5,000 barrels of oil equivalent per day.

With this new chapter brings a new set of partners for Strathcona – our public shareholders. Our commitment to our new shareholders is twofold: (1) to use every lever in our control to maximize the long-term intrinsic value of your shares, and (2) to communicate directly and honestly about our accomplishments and setbacks in pursuing this goal.

In reviewing 2023, we will discuss our performance across the three categories Strathcona's Board of Directors has chosen to drive the company's annual incentive plan: (1) health, safety & environment, (2) reserves, and (3) operations. These measures have been chosen by our Board because they reflect both what contribute to long-term shareholder value creation and what is in management's control.

Our health, safety & environmental performance in 2023 was strong, with a total recordable injury frequency (TRIF) of 0.49 demonstrating best-in-industry performance. While lagging indicators offer one performance dimension, Strathcona has been dutifully increasing the tracking of leading indicators and preventative metrics. We also consistently demonstrate a high level of emergency response preparedness.

On the reserves front, Strathcona had a strong year. As detailed in our March 11th reserves highlights, in 2023 we delivered a 2.4x organic proved developed producing (PDP) recycle ratio and replaced 199% of proved plus probable (2P) reserves organically. Pro forma for the Pipestone acquisition, PDP, proved (1P) and 2P reserves grew 19%, 1% and 1% per share, respectively. As of year end, Strathcona has a 2P reserve life index of 38.5 years and a $13.6 billion 1P PV-10 after tax, uniquely positioning the company for significant future growth as we seek to optimize our reserve life index.

Finally, from an operational perspective, Strathcona's Cold Lake Thermal segment had a standout year in 2023. Exit-to-exit production grew approximately 20% through a combination of new well drilling, improved base production performance and continued debottlenecking of established infrastructure.

Strathcona's Montney segment also experienced significant 2023 growth, and while natural gas prices were lower in 2023 vs. 2022, approximately 50% of our natural gas production is naturally hedged with the natural gas consumed in our thermal operations, reducing cash flow volatility. Our Montney assets also produce a significant volume of liquids, including condensate, which drives strong short-cycle economics and provides a further natural hedge with condensate required for blending heavy oil volumes shipped by pipeline.

Performance in our Lloydminster Heavy Oil segment was steady, with 2022-acquired thermal assets slightly below expectations as we shifted focus from short-term volume growth to longer term value creation. These thermal properties contain multiple stacked Mannville channels that respond extremely well to steam assisted gravity drainage (SAGD) extraction, and our recent extensive stratigraphic delineation program has identified significantly more prospective channels than originally evaluated. These are long-life assets with very strong full-cycle economics and decades of well-defined future resource. Strathcona's focus on long-term value growth and history of continuous improvement as demonstrated on its Cold Lake thermal properties is an excellent proxy for the bright future for its Lloydminster thermal properties.

Looking ahead, we are excited by the many opportunities on the horizon for Strathcona. We will continue our unwavering commitment to safe, reliable and environmentally sound operations. Strathcona's long reserve life index positions us for substantial future growth while generating meaningful free cash flow and returns to shareholders at the same time. As we move forward, the maximization of long-term intrinsic value per share will guide our decisions. Welcome to our new public shareholders. We look forward to keeping you up to date on our journey.

Adam Waterous
Executive Chairman

Rob Morgan
President and CEO

STRATHCONA
RESOURCES LTD

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEARS ENDED DECEMBER 31, 2023 AND 2022

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following management's discussion and analysis ("**MD&A**") of financial condition and results of operations for Strathcona Resources Ltd. (the "**Company**" or "**Strathcona**") is dated March 26, 2024 and should be read in conjunction with the Company's audited consolidated financial statements (and related notes) as at and for the years ended December 31, 2023 and 2022 (the "**annual financial statements**"). The annual financial statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**"), in Canadian dollars, except where indicated otherwise. The annual financial statements and MD&A of Strathcona have been prepared by management and were approved by the Company's Board of Directors.

This MD&A contains forward looking information; see "Risk Factors" in this MD&A and "Forward-Looking Information" at the end of this MD&A for further information. The following MD&A also contains financial measures that do not have a standardized meaning under IFRS; see "Specified Financial Measures" at the end of this MD&A for further information. This MD&A contains certain oil and gas metrics and measures; see "Advisories Regarding Oil & Gas Information" at the end of this MD&A.

All dollar amounts are referenced in Canadian dollars and, in the case of amounts presented in tabular form, in millions of Canadian dollars, in each case except when noted otherwise. All per unit figures are based on commodity sales volumes, net of blending, unless otherwise indicated. Sales volumes differ from production volume as a result of changes in oil inventory. Refer to the "Segment Results" section of this MD&A for additional information.

DESCRIPTION OF BUSINESS

Strathcona is a corporation resulting from the amalgamation of Strathcona and Pipestone Energy Corp. ("**Pipestone**") on October 3, 2023 (the "**Pipestone Acquisition**"), pursuant to a plan of arrangement under the Business Corporations Act (Alberta) (the "**ABCA**"), (the "**Arrangement**"). Upon completion of the Arrangement, Strathcona's Common Shares were listed on the TSX under the trading symbol "SCR" and commenced trading on October 5, 2023. Strathcona exists under, and is governed by, the provisions of the ABCA. This MD&A reflects the historical financial information of Strathcona Resources Ltd., commencing on October 3, 2023 also reflects the results of Pipestone.

At December 31, 2023, approximately 90.8% of the Company's shares were owned by certain limited partnerships comprising of Waterous Energy Fund and its affiliates (collectively, "**WEF**").

Strathcona has grown its business through a series of strategic acquisitions. The significant differences in financial and operational results of the Company for the three and twelve months ended December 31, 2023 compared to prior periods presented within this MD&A are primarily the result of the transactions discussed below and in the Recent Developments section of this MD&A.

On March 11, 2022, Strathcona acquired the remaining 43% interest in both Caltex Resources Ltd. ("**Caltex**") and Stickney Resources Ltd. ("**Stickney**") (together, referred to as the "**Caltex and Stickney Amalgamation**"). The properties acquired from Caltex were heavy oil properties now included in the Lloydminster Heavy Oil segment. The Tucker thermal oil property acquired from Stickney is now included in the Cold Lake Thermal segment.

On August 29, 2022, Strathcona acquired Serafina Energy Ltd. ("**Serafina**") (transaction referred to as the "**Serafina Acquisition**"). The properties acquired were thermal heavy oil properties now included in the Lloydminster Heavy Oil segment.

Refer to Note 4 of the annual financial statements for further details on these transactions.

RECENT DEVELOPMENTS

On March 25, 2024, Strathcona received approval from its lenders to increase the Revolving Credit Facility to $2.5 billion and to extend the maturity date to four years from closing. Closing is subject to completion of documentation, and is anticipated to occur on or about March 28, 2024.

2024 GUIDANCE

In light of weak natural gas prices, Strathcona has elected to defer the tie-in of its 3-well 13-25 pad at Groundbirch, which was spud in early 2024 and previously planned for tie-in mid-year. The deferral of the Groundbirch wells is expected to reduce calendar year 2024 production by approximately 15 MMcf per day. As a result, full-year average production guidance for 2024 is now expected to be in the range of 187,500 – 192,500 boe per day, down from 190,000 – 195,000 boe per day disclosed in the Company's November 13, 2023 news release.

	2024 Guidance - Previously Reported	2024 Guidance - Amended
Production (boe/d)	**190,000 - 195,000**	**187,500 - 192,500**
Capital expenditures ($ billions)	**1.3**	**1.3**

PRODUCTION VOLUMES

	Three Months Ended			Year Ended	
	December 31, 2023	December 31, 2022	September 30, 2023	**December 31, 2023**	December 31, 2022
Bitumen (bbl/d)	**59,845**	49,792	58,179	**55,768**	46,552
Heavy oil (bbl/d)	**52,736**	56,768	51,256	**53,707**	33,685
Condensate and light oil (bbl/d)	**19,184**	9,023	10,092	**12,011**	8,453
Total oil production (bbl/d)	**131,765**	115,583	119,527	**121,486**	88,690
Other NGLs (bbl/d)	**11,906**	8,142	7,873	**9,021**	7,329
Natural gas (mcf/d)	**254,361**	117,878	120,366	**149,715**	110,308
Total (boe/d)	**186,064**	143,371	147,461	**155,459**	114,404
% oil and condensate	**71 %**	81 %	81 %	**78 %**	78 %
% liquids	**77 %**	86 %	86 %	**84 %**	84 %

Production volumes increased by 42,693 boe per day for the three months ended December 31, 2023 to an average of 186,064 boe per day compared to 143,371 boe per day for the same quarter of 2022. The increase is primarily attributable to production from properties added through the Pipestone Acquisition, which was completed in the fourth quarter of 2023. The Pipestone Acquisition contributed condensate and light oil production of 8,850 bbl per day, other NGLs of 3,061 bbl per day and natural gas of 110,654 mcf per day in the three months ended December 31, 2023. The remaining production increase is attributable to strong well results from the 2022 and 2023 capital programs, particularly in the Cold Lake Thermal segment where bitumen production increased 20% in the three months ended December 31, 2023, compared to the same period in 2022.

Production volumes increased by 41,055 boe per day for the year ended December 31, 2023 to an average of 155,459 boe per day compared to 114,404 boe per day for the same period of 2022. The increase is primarily attributable to incremental production of 4,200 boe per day from properties acquired through the Caltex and Stickney Amalgamation, 17,600 boe per day from properties acquired through the Serafina Acquisition and 7,651 boe per day from properties acquired through the Pipestone Acquisition. The remaining production increase is attributable to strong well results from the 2022 and 2023 capital programs, particularly in the Cold Lake Thermal segment where bitumen production increased 20% in the year ended December 31, 2023, compared to the same period in 2022.

Production volumes increased approximately 26% during the three months ended December 31, 2023 compared to the three months ended September 30, 2023 due primarily to the 30,354 boe per day incremental production attributable to properties acquired through the Pipestone Acquisition.

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
	December 31, 2023	December 31, 2022	September 30, 2023	**December 31, 2023**	December 31, 2022
Benchmark Pricing					
US$/bbl unless otherwise indicated					
WTI[1]	**78.32**	82.65	82.26	**77.62**	94.23
WCS Hardisty[2]	**56.43**	56.99	69.38	**58.92**	76.01
WCS USGC[3]	**71.59**	67.63	77.89	**69.73**	85.80
WTI-WCS Hardisty differential	**(21.89)**	(25.66)	(12.88)	**(18.70)**	(18.22)
WTI-WCS USGC differential	**(6.73)**	(15.01)	(4.37)	**(7.89)**	(8.43)
NYMEX-AECO differential (US$/MMbtu)[4]	**(1.13)**	(2.56)	(0.95)	**(0.79)**	(2.80)
Condensate differential[5]	**(2.09)**	0.75	(4.26)	**(1.03)**	(0.45)
Average FX rate (C$/US$)	**1.3618**	1.3577	1.3410	**1.3495**	1.3015
CAD$/bbl unless otherwise indicated					
WTI[1]	**106.72**	112.22	110.38	**104.78**	122.38
WCS Hardisty[2]	**76.85**	77.40	93.04	**79.51**	98.51
WCS USGC[3]	**97.49**	91.85	104.45	**94.10**	111.27
AECO 5A (C$/mcf)[6]	**2.30**	5.11	2.60	**2.64**	5.31
Condensate par at Edmonton	**103.81**	113.23	104.60	**103.36**	121.78
AESO weighted average pool price (C$/MWh)[7]	**83.05**	217.79	155.44	**136.45**	162.46
CDOR (%)[8]	**5.41**	4.32	5.33	**5.17**	2.41

(1) Calendar month average of West Texas Intermediate (“WTI”) oil.
(2) Western Canadian Select (“WCS”).
(3) United States Gulf Coast ("USGC").
(4) New York Mercantile Exchange ("NYMEX") Futures Last Day differential / Relates to the Alberta Energy Company ("AECO") 7A Index.
(5) Condensate / WTI differential at Edmonton.
(6) AECO hub pricing.
(7) Alberta Electric System Operator ("AESO") weighted average pool prices.
(8) Canadian Dollar Offered Rate ("CDOR") percentage for 1 month tenors.

WTI crude oil prices decreased 5% in the fourth quarter of 2023 compared to the third quarter of 2023 and the fourth quarter of 2022. During the first half of 2023, the price of crude oil declined, impacted by higher inventory levels. In the third quarter of 2023, crude oil prices increased as a result of strong demand, tight inventory levels and sustained global supply curtailments from OPEC+, notably Saudi Arabian and Russian oil producers. However, during the fourth quarter of 2023, WTI began to weaken due to continued supply growth, predominantly from the US, that coincided with indications of slowing global oil demand growth.

The WTI-WCS Hardisty differential widened in the fourth quarter of 2023 compared to the third quarter of 2023 due to higher production and outages at Alberta refineries resulting in exports above available pipeline capacity. The commissioning of the Trans Mountain Pipeline Expansion Project, which is scheduled for the first half of 2024, is expected to ease such egress constraints. The expansion will add approximately 590,000 bbl per day of transport capacity to the existing system and is anticipated to improve the Hardisty differential realized by Canadian oil producers. WCS quality differentials were relatively consistent year-over-year, differentials widened in the second half of 2022 and first half of 2023 due to unplanned refinery maintenance, high global refining utilization, increasing supply of medium and light oil into the global market from OPEC+, Strategic Petroleum Reserve releases from the US and refined product price volatility. The WCS USGC is a heavy oil benchmark for sales of products at the USGC and its differential relative to WTI prices is representative of the heavy oil quality discount and is influenced by global heavy oil refining capacity as well as supply. The WTI-WCS USGC differential was impacted by the same factors described above.

AECO 5A natural gas prices decreased 12% in the fourth quarter of 2023 compared to the third quarter of 2023. Canadian natural gas production reached all-time highs in 2023 while unseasonably warm weather conditions in the first quarter of 2023 curtailed seasonal downstream demand. Due to the building of supply and storage levels, AECO 5A natural gas prices remained rangebound throughout 2023 and depressed relative to the strong pricing experienced in 2022. In the fourth quarter of 2023, a warm start to the winter season put further downward pressure on natural gas prices.

REVENUE AND REALIZED PRICES

Oil and Natural Gas Sales - Net of Blending

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2023**	December 31, 2022	September 30, 2023	**December 31, 2023**	December 31, 2022
Bitumen blend	**591.8**	491.1	670.8	**2,280.8**	2,358.8
Heavy oil, blended and raw	**437.3**	464.3	489.5	**1,809.1**	1,326.5
Condensate and light oil	**172.3**	89.3	94.4	**431.0**	341.3
Other natural gas liquids	**26.9**	24.6	16.0	**79.4**	96.8
Natural gas	**59.3**	55.6	29.5	**148.0**	220.0
Oil and natural gas sales	**1,287.6**	1,124.9	1,300.2	**4,748.3**	4,343.4
Gain (loss) purchased product	**1.0**	1.1	0.4	**(0.2)**	0.4
Bitumen - blending cost	**(243.5)**	(210.9)	(201.8)	**(890.3)**	(859.6)
Heavy oil - blending cost	**(41.3)**	(55.2)	(36.7)	**(168.0)**	(178.3)
Oil and natural gas sales - net of blending[(1)]	**1,003.8**	859.9	1,062.1	**3,689.8**	3,305.9

(1) A non-GAAP financial measure which does not have a standardized meaning under IFRS; see "Specified Financial Measures" section of this MD&A.

Oil and natural gas sales, net of blending, increased 17% for the three months ended December 31, 2023 to $1,003.8 million compared to $859.9 million for the same quarter in 2022. This increase is primarily attributable to increased sales volumes from the Cold Lake Thermal segment and properties acquired in the Pipestone Acquisition.

Oil and natural gas sales, net of blending, increased 12% for the year ended December 31, 2023 to $3,689.8 million from $3,305.9 million for the same period in 2022. This increase is primarily attributed to higher sales volumes as a result of properties added through the Serafina Acquisition and the Pipestone Acquisition which added $569.6 million and $119.1 million, respectively, partially offset by lower average benchmark commodity prices.

Oil and natural gas sales, net of blending, decreased 5% for the three months ended December 31, 2023 to $1,003.8 million compared to $1,062.1 million for the three months ended September 30, 2023. This decrease is primarily due to lower realized prices attributed to lower average benchmark commodity prices, partially offset by sales volumes added from the Pipestone Acquisition.

Average Realized Prices

	Three Months Ended			Year Ended	
	December 31, 2023	December 31, 2022	September 30, 2023	**December 31, 2023**	December 31, 2022
Bitumen blend ($/bbl)[1][2]	**63.07**	59.41	88.06	**68.31**	89.39
Heavy oil, blended and raw ($/bbl)[1][2]	**84.23**	82.39	92.53	**83.00**	92.99
Condensate and light oil ($/bbl)	**97.62**	107.33	101.67	**98.30**	116.32
Realized oil ($/bbl)	**76.46**	74.42	91.16	**77.79**	93.25
Other natural gas liquids ($/bbl)	**24.56**	32.97	22.09	**24.12**	36.19
Natural gas ($/mcf)	**2.53**	5.16	2.66	**2.71**	5.46
Combined ($/boe)	**59.17**	66.01	77.55	**64.83**	79.77

(1) Realized prices are calculated using oil and natural gas sales, net of blending.
(2) A non-GAAP financial measure which does not have a standardized meaning under IFRS; see “Specified Financial Measures” section of this MD&A.

Combined realized price decreased 10% for the three months ended December 31, 2023 to $59.17 per boe compared to $66.01 per boe in the same quarter of 2022.

Combined realized price decreased 19% for the year ended December 31, 2023 to $64.83 per boe compared to $79.77 per boe in the same period of 2022.

Combined realized price decreased 24% for the three months ended December 31, 2023 to $59.17 per boe compared to $77.55 per boe for the three months ended September 30, 2023.

These decreases are primarily due to lower average benchmark WTI and AECO prices across all periods.

ROYALTIES

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2023**	December 31, 2022	September 30, 2023	**December 31, 2023**	December 31, 2022
Crown royalties	**96.3**	102.8	142.8	**405.1**	444.3
Freehold royalties	**14.0**	12.3	16.7	**56.7**	38.2
Gross overriding royalties	**17.2**	12.2	38.1	**73.9**	169.8
Other royalties	**7.4**	7.7	5.1	**21.2**	14.5
Royalties	**134.9**	135.0	202.7	**556.9**	666.8
Effective royalty rate (%)[1]	**13.4 %**	15.7 %	19.1 %	**15.1 %**	20.2 %

(1) A non-GAAP financial measure which does not have a standardized meaning under IFRS; see "Specified Financial Measures" section of this MD&A.

For the three months and year ended December 31, 2023, the average effective royalty rate was 13.4% and 15.1%, respectively, compared to 15.7% and 20.2% for the same periods in 2022. These decreases are primarily the result of lower benchmark commodity prices.

For the three months ended December 31, 2023, the average effective royalty rate decreased to 13.4% from 19.1% in the third quarter of 2023. This decrease is primarily driven by lower average benchmark commodity prices during the fourth quarter of 2023, as well as favorable adjustments received on annual government filings relating to production within oil sands projects.

PRODUCTION AND OPERATING EXPENSES

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2023**	December 31, 2022	September 30, 2023	Year Ended **December 31, 2023**	December 31, 2022
Production and operating - Energy	**72.5**	117.1	81.4	**322.3**	330.2
Production and operating - Non-energy	**133.3**	97.6	113.9	**474.0**	310.0
Production and operating expenses	**205.8**	214.7	195.3	**796.3**	640.2
Production and operating - Energy ($/boe)	**4.27**	8.99	5.94	**5.66**	7.97
Production and operating - Non-energy ($/boe)	**7.86**	7.49	8.32	**8.33**	7.48
Production and operating expenses ($/boe)	**12.13**	16.48	14.26	**13.99**	15.45

Production and operating expenses decreased to $205.8 million ($12.13 per boe) for the three month period ended December 31, 2023 from $214.7 million ($16.48 per boe) in the same period in 2022. This decrease is primarily attributable to lower energy costs at Cold Lake Thermal as a result of lower natural gas and power prices. Non-energy production and operating costs increased primarily due to the Pipestone Acquisition, which added $20.3 million in incremental non-energy costs in the three month period. On a per boe basis, production and operating expenses are lower due to the Pipestone Acquisition assets, which generally have a lower production and operating cost profile compared to the Cold Lake Thermal and Lloydminster Heavy Oil segments.

Production and operating expenses increased to $796.3 million ($13.99 per boe) for the year ended December 31, 2023, from $640.2 million ($15.45 per boe) in the same period in 2022. This increase is primarily attributable to increased production volumes as a result of the Caltex and Stickney Amalgamation, the Serafina Acquisition and the Pipestone Acquisition, which added $107.7 million in incremental non-energy production and operating costs in 2023, and general cost inflation across all segments, offset by lower energy costs at Cold Lake Thermal as a result of lower natural gas prices.

Production and operating expenses increased during the three months ended December 31, 2023 compared to the three months ended September 30, 2023 due to the Pipestone Acquisition, which added incremental non-energy production and operating costs in the period mentioned above. The incremental costs were offset by lower energy costs due to lower natural gas and power prices. On a per boe basis, production and operating expenses were lower due to the Pipestone Acquisition assets, which, during the fourth quarter of 2023, had a lower production and operating cost profile compared to the Cold Lake Thermal and Lloydminster Heavy Oil segments.

TRANSPORTATION AND PROCESSING EXPENSES

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2023**	December 31, 2022	September 30, 2023	Year Ended **December 31, 2023**	December 31, 2022
Transportation expenses	**109.7**	108.8	107.6	**435.9**	232.5
Processing expenses	**26.0**	6.3	6.9	**47.0**	25.7
Transportation and processing expenses	**135.7**	115.1	114.5	**482.9**	258.2
$ per boe	**8.00**	8.84	8.36	**8.49**	6.23

Transportation and processing expenses increased to $135.7 million ($8.00 per boe) and $482.9 million ($8.49 per boe) for the three months and year ended December 31, 2023, respectively, from $115.1 million ($8.84 per boe) and $258.2 million ($6.23 per boe) in the same periods of 2022. These increases are primarily attributable to the Caltex and Stickney Amalgamation, the Serafina Acquisition and the Pipestone Acquisition, all of which resulted in additional production volumes. Incremental production from the Caltex and Stickney Amalgamation and Serafina Acquisition is transported by truck and rail which has a higher transportation cost per barrel compared to legacy Strathcona heavy oil assets which are primarily transported by pipeline. Processing expenses are higher due to the Pipestone Acquisition, which contain flow-through capital charges as the majority of the production is processed through third party facilities.

Transportation and processing expenses increased by 19% for the three months ended December 31, 2023 to $135.7 million ($8.00 per boe) from $114.5 million ($8.36 per boe) in the third quarter of 2023 as a result of incremental production from the properties acquired in the Pipestone Acquisition.

DEPLETION, DEPRECIATION AND AMORTIZATION ("DD&A")

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2023**	 December 31, 2022	 September 30, 2023	Year Ended **December 31, 2023**	 December 31, 2022
Depletion expense	**214.8**	137.6	163.6	**699.6**	380.5
Depreciation and amortization expense	**12.7**	6.8	8.0	**33.3**	15.2
DD&A	**227.5**	144.4	171.6	**732.9**	395.7
$ per boe	**13.41**	11.08	12.53	**12.88**	9.55

DD&A expense increased 58% for the three months ended December 31, 2023 to $227.5 million ($13.41 per boe) compared to $144.4 million ($11.08 per boe) for the same quarter of 2022. For the year ended December 31, 2023, DD&A expense increased 85% to $732.9 million ($12.88 per boe) from $395.7 million ($9.55 per boe) for the same period of 2022. These increases are primarily due to a higher DD&A rate as well as increased production volumes as a result of the Caltex and Stickney Amalgamation, the Serafina Acquisition and the Pipestone Acquisition.

DD&A expense increased 33% for the three months ended December 31, 2023 to $227.5 million ($13.41 per boe) compared to $171.6 million ($12.53 per boe) for the three months ended September 30, 2023. This is predominantly due to DD&A on right-of-use assets and oil and gas properties acquired in the Pipestone Acquisition.

GENERAL AND ADMINISTRATION EXPENSES (“G&A”)

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2023**	 December 31, 2022	 September 30, 2023	Year Ended **December 31, 2023**	 December 31, 2022
G&A expenses	**24.5**	24.2	20.7	**91.9**	68.8
$ per boe	**1.44**	1.86	1.51	**1.61**	1.66

For the three months and year ended December 31, 2023, G&A expenses increased to $24.5 million ($1.44 per boe) and $91.9 million ($1.61 per boe), respectively, from $24.2 million ($1.86 per boe) and $68.8 million ($1.66 per boe) in the same periods in 2022. The increases are primarily due to higher staffing levels, consultant fees and information technology costs incurred following the Caltex and Stickney Amalgamation, the Serafina Acquisition and the Pipestone Acquisition.

G&A expenses increased during the three months ended December 31, 2023 compared to the three months ended September 30, 2023 due to higher staffing levels, consultants and professional fees incurred as a result of the Pipestone Acquisition.

INTEREST

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2023**	 December 31, 2022	 September 30, 2023	Year Ended **December 31, 2023**	 December 31, 2022
Interest expense	**51.6**	49.9	50.2	**206.2**	109.4
Weighted average interest rate (%)	**6.7 %**	6.1 %	6.3 %	**6.5 %**	5.5 %

Interest expense increased 3% for the three months ended December 31, 2023 to $51.6 million compared to $49.9 million for the same quarter of 2022. This increase is primarily the result of higher interest rates, partially offset by savings on interest rate swaps.

For the year ended December 31, 2023, interest expense increased 88% to $206.2 million from $109.4 million for the same period of 2022. This increase is primarily the result of incremental borrowings drawn in conjunction with the Caltex and Stickney Amalgamation and Serafina Acquisition as well as higher interest rates, partially offset by savings on interest rate swaps.

During the year ended December 31, 2023, the Company recorded $46.4 million in interest expense on the Senior Notes (as defined in the "Capital Resources" section of this MD&A) (December 31, 2022 – $44.7 million); and $178.4 million in interest expense on the Credit Facilities (as defined in the "Capital Resources" section of this MD&A) (December 31, 2022 - $64.7 million); and a realized gain of $18.6 million on interest rate swaps (December 31, 2022 - $nil).

Interest expense remained consistent during the three months ended December 31, 2023 compared to the three months ended September 30, 2023.

The impact of higher interest rates in 2023 were partially mitigated through interest rate swaps. See the "*Risk Management - Market Risk - Interest Rate Risk*" section of this MD&A.

FINANCE COSTS

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2023**	December 31, 2022	September 30, 2023	December 31, 2023	December 31, 2022
Accretion of lease obligations	**5.9**	2.7	3.0	**14.5**	11.4
Accretion of decommissioning provision	**7.1**	2.7	7.1	**28.7**	9.5
Amortization of debt issuance costs	**3.5**	3.3	3.2	**13.0**	8.9
Accretion of other obligations	**5.1**	—	4.8	**19.1**	—
Finance costs	**21.6**	8.7	18.1	**75.3**	29.8

For the three months ended December 31, 2023, finance costs increased to $21.6 million compared to $8.7 million in the same quarter of 2022. For the year ended December 31, 2023, finance costs increased to $75.3 million from $29.8 million in the same period of 2022. These increases are due to higher accretion as a result of decommissioning liabilities assumed through the Caltex and Stickney Amalgamation, the Serafina Acquisition and the Pipestone Acquisition; higher amortization of debt issuance costs as a result of fees incurred on the Credit Facilities; and accretion of other obligations which is related to the asset-backed financing agreement entered into in late December 2022 (see Note 7 of the annual financial statements).

Finance costs increased 16% for the three months ended December 31, 2023 to $21.6 million compared to $18.1 million for the three months ended September 30, 2023. This is predominantly due to accretion of lease obligations, the balance of which increased by $106.2 million during the three months ended December 31, 2023, by virtue of the Pipestone Acquisition.

INCOME TAX AND TAX POOLS

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2023**	December 31, 2022	September 30, 2023	**December 31, 2023**	December 31, 2022
Current tax (recovery)	**—**	—	—	**(46.9)**	—
Deferred tax expense (recovery)	**90.0**	42.2	44.6	**296.2**	(371.9)
Income tax expense (recovery)	**90.0**	42.2	44.6	**249.3**	(371.9)

During the year ended December 31, 2023, a current tax recovery of $46.9 million was recorded upon filing of the final tax return of Serafina, which resulted from an income tax election to apply fair value treatment to financial derivative contracts. The current tax recovery was offset by a corresponding deferred tax expense due to the liability recorded by Strathcona to reflect the income inclusion related to the election filed. The remaining deferred tax expense recorded during 2023 relates primarily to net income for the period.

During the year ended December 31, 2022, a deferred tax recovery of $371.9 million was recorded. Deferred tax recoveries were recorded to offset deferred tax liabilities on the Caltex Amalgamation and the Serafina Acquisition. The Company determined that its deductible temporary differences met the threshold for utilization after the Serafina Acquisition on August 29, 2022.

Tax Pools

As at December 31, 2023, the Company had approximately $6,081.1 million (December 31, 2022 - $6,038.1 million) of tax pools available for deduction in future periods as shown in the table below.

($ millions, unless otherwise indicated)	Annual Pool Deduction Rate	**December 31, 2023**	December 31, 2022
Canadian oil and gas property expenditures	10 %	**893.4**	955.4
Canadian development expenditures(1)	30 %	**1,168.8**	731.0
Canadian exploration expenditures(1)	100 %	**34.1**	8.8
Undepreciated capital costs(2)	4 % - 55 %	**1,371.0**	1,178.9
Non-capital losses	100 %	**2,173.1**	2,711.7
Other(3)		**440.7**	452.3
Total tax pools		**6,081.1**	6,038.1

(1) Amount is net of tax pools where deductibility is uncertain.

(2) As at December 31, 2023, approximately 96% (December 31, 2022 – 97%) of costs in this pool have an annual deduction rate of 25%.

(3) Other tax deductions include scientific research and experimental development costs and credits and financing costs. As at December 31, 2023, approximately 89% (December 31, 2022 – 86%) of these deductions have an annual deduction rate of 100%.

RISK MANAGEMENT

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities. These risks include credit risk, liquidity risk and market risk.

Credit Risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. This will arise principally from outstanding receivables related to oil and natural gas customers, counterparties with which financial derivative contracts are held and joint interest partners.

On entering into any business contract, the extent to which the arrangement exposes the Company to credit risk is considered. The Company's policy to mitigate credit risk associated with these balances is to establish relationships with reputable counterparties, review the financial capacity of its counterparties, request prepayment as deemed advisable and, in certain circumstances, the Company may seek enhanced credit protection from a counterparty or purchase accounts receivable insurance.

Market Risk

Market risk is the risk that the future fair value or cash flows of a financial instrument will fluctuate due to changes in market prices. Market risk is composed of commodity price risk, foreign exchange risk and interest rate risk. The Company uses financial risk management contracts to reduce volatility in financial results and to ensure a certain level of cash flow to fund planned capital projects.

Commodity Price Risk

The Company's operational results and financial condition are largely dependent on the commodity price received for oil and natural gas production. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, weather, economic and geopolitical factors. The Company uses financial derivative instruments and other commodity derivative mechanisms to help limit the adverse effects of commodity price volatility. However, the Company does not have commodity contracts in place for all its production and expects there will always be a portion that remains unhedged. Furthermore, the Company may use financial derivative instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, the Company may forego the benefits that would otherwise be experienced if commodity prices increase.

The following table summarizes the Company's commodity contracts outstanding as at the date of this MD&A.

Term	Contract[(1)]	Index	Currency	Volume	Units	Price
Mar 1, 2024 - May 31, 2024	Swap	WTI	USD	5,000	bbl/d	$48.10
Mar 1, 2024 - Mar 31, 2024	Collar	WTI	USD	75,000	bbl/d	$60.00/$105.29
Dec 1, 2023 - Mar 31, 2024	Collar	WTI	USD	18,000	bbl/d	$60.00/$91.01
Feb 1, 2024 - Mar 31, 2024	Collar	WTI	USD	10,000	bbl/d	$60.00/$90.83
Jan 1, 2024 - Mar 31, 2024	Swap	WTI	CAD	2,000	bbl/d	$111.45
Apr 1, 2024 - Jun 30, 2024	Swap	WTI	CAD	1,750	bbl/d	$109.89
May 1, 2024 - Dec 31, 2024	Swap	WCS	USD	10,000	bbl/d	$(14.25)
Nov 1, 2023 - Apr 30, 2024	Collar	AECO	CAD	120,000	GJ/d	$2.00/$3.63
May 1, 2024 - May 31, 2024	Collar	AECO	CAD	60,000	GJ/d	$2.00/$2.27
May 1, 2024 - May 31, 2024	Swap	AECO	CAD	60,000	GJ/d	$2.03

(1) For swap contracts, Strathcona receives the fixed price and pays the index. Call options are in-the-money if the index price is above the strike price. For collars, Strathcona receives the floor price if the index is below the floor and the cap price if the index is above the cap.

The company has premiums associated with expired bought calls totaling US$86.3 million, which are payable between September 2025 and February 2026.

Foreign Exchange Risk

The Company is exposed to fluctuations of the CAD to USD exchange rate given commodity pricing is directly influenced by USD denominated benchmark pricing. In addition, the Company periodically borrows from its Credit Facilities in USD and the Senior Notes are denominated in USD. The Company actively manages foreign exchange risk using foreign exchange derivatives.

As at December 31, 2023, the Company had foreign exchange collars of US$30.5 million per month from March 1, 2024 to February 28, 2025 (refer to Note 15 in the annual financial statements). Subsequent to year-end, the Company completed a restructuring of its foreign exchange hedges by selling USD put options, the premium from which was used to replace the existing foreign exchange collar with a new contract.

The following table summarizes the Company's foreign exchange contract on revenues as at the date of this MD&A.

Term	Contract	USD per Month	CAD/USD Floor	CAD/USD Ceiling
Mar 1, 2024 - Feb 28, 2026	Collar	60.0 million	1.2500	1.3800

The following table summarizes the Company's foreign exchange contract on the Senior Notes as at the date of this MD&A.

Expiry	Contract	USD	CAD/USD Strike
Jul 31, 2026	Put Option	500.0 million	1.3475

Interest Rate Risk

The Company is exposed to movements in floating interest rates on the Credit Facilities and other liabilities. The Company is not exposed to interest rate risk on the Senior Notes as they bear a fixed interest rate.

The following table summarizes the Company's risk management contracts in place to fix interest rates as at the date of this MD&A.

Notional (C$)	Term	Contract	Index	Contract Price
1,500.0 million	May 1, 2023 - Apr 30, 2028	Swap	1 month CDOR	3.4316%

For a listing of the Company's commodity contracts, foreign exchange and interest rate contracts outstanding as at December 31, 2023 refer to Note 15 in the annual financial statements.

Refer to the “Capital Resources” section of this MD&A for information on the Company’s cross-currency interest rate swaps related to debt.

The following table summarizes the Company's gains and losses on risk management contracts.

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2023**	December 31, 2022	September 30, 2023	**December 31, 2023**	December 31, 2022
Realized (gain) loss on risk management contracts(1)	**(19.5)**	15.8	56.1	**42.4**	278.6
Unrealized (gain) loss on risk management contracts(2)	**(109.6)**	61.3	209.7	**(112.0)**	(90.4)
Total (gain) loss on risk management contracts	**(129.1)**	77.1	265.8	**(69.6)**	188.2
Realized (gain) loss on risk management contract per boe	**(1.15)**	1.20	4.09	**0.74**	6.72

(1) Includes realized (gains) losses on commodity price contracts and foreign exchange contracts.

(2) Includes the movement in the valuation of commodity price contracts, foreign exchange contracts and interest rate swaps.

Strathcona realized a gain on risk management contracts of $19.5 million and a realized loss of $42.4 million, for the three months and year ended December 31, 2023, respectively, compared to a loss of $15.8 million and $278.6 million for the same periods in 2022 and a loss of $56.1 million for the three months ended September 30, 2023. The realized gains or losses on risk management contracts are due to realized commodity benchmark prices in comparison to contracted hedge pricing. The impact of cash settlements on foreign exchange contracts was nominal for the periods presented.

As at December 31, 2023, the mark-to-market value of risk management contracts was a net liability of $103.7 million (December 31, 2022 - net liability of $212.6 million). Unrealized gains and losses represent the change in the mark-to-market values of these contracts due to the fluctuation of forward commodity prices, exchange rates and interest rates. The significant assumptions made in determining the fair value of financial instruments are disclosed in Note 15 to the annual financial statements.

TRANSACTION RELATED COSTS

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2023**	December 31, 2022	September 30, 2023	**December 31, 2023**	December 31, 2022
Transaction related (recoveries) costs	**(1.3)**	6.0	3.5	**3.8**	11.2

Transaction related costs primarily pertain to the legal and consulting costs associated with corporate transactions, as well as consulting fees for ongoing integration work. The transaction costs recovered for the three months ended December 31, 2023 primarily relate to the Pipestone Acquisition, which were originally expensed and subsequently capitalized.

CAPITAL EXPENDITURES

The following table summarizes the Company's capital expenditures by segment.

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2023**	 December 31, 2022	 September 30, 2023	Year Ended **December 31, 2023**	 December 31, 2022
Cold Lake Thermal	**69.7**	88.1	78.0	**306.0**	256.2
Lloydminster Heavy Oil	**96.2**	85.7	99.2	**360.5**	160.2
Montney	**139.3**	54.7	80.7	**351.0**	201.5
Corporate	**2.6**	—	2.3	**10.9**	3.0
Capital expenditures	**307.8**	228.5	260.2	**1,028.4**	620.9

The following table summarizes the Company's capital expenditures by category.

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2023**	 December 31, 2022	 September 30, 2023	Year Ended **December 31, 2023**	 December 31, 2022
Drilling, completion and equipping	**177.3**	132.5	152.9	**592.5**	375.8
Facilities and pipelines	**96.5**	76.9	78.3	**311.0**	179.3
Recompletion, workovers and polymer powder	**19.2**	15.7	17.6	**70.1**	47.3
Capitalized G&A and other expenditures	**14.8**	3.4	11.4	**54.8**	18.5
Capital expenditures	**307.8**	228.5	260.2	**1,028.4**	620.9

For the three months ended December 31, 2023, drilling, completion and equipping activities accounted for 58% of capital expenditures as the Company drilled 59 new wells during the quarter; 13 in Cold Lake Thermal, 40 in Lloydminster Heavy Oil and 6 in Montney. Drilling, completion and equipping activities for the year ended December 31, 2023 accounted for 58% of capital expenditures as the Company drilled 236 new wells; 57 in Cold Lake Thermal, 159 in Lloydminster Heavy Oil and 20 in Montney.

Capital expenditures increased 35% for the three months ended December 31, 2023 to $307.8 million compared to $228.5 million for the same quarter of 2022. This increase is primarily the result of $59.2 million of capital spending on the assets acquired through the Pipestone Acquisition, $18.3 million in increased completion activity at the Company's Montney segment and $5.3 million in increased facilities spend at the Company's Cold Lake Thermal segment.

Capital expenditures increased 66% for the year ended December 31, 2023 to $1,028.4 million compared to $620.9 million for the year ended December 31, 2022. This increase is the result of an incremental $273.0 million of capital spending made on the assets acquired through the Caltex and Stickney Amalgamation, the Serafina Acquisition and the Pipestone Acquisition, which increased drilling and completion activity at the Company's Montney and Cold Lake Thermal segments.

FOREIGN EXCHANGE

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2023**	 December 31, 2022	 September 30, 2023	Year Ended **December 31, 2023**	 December 31, 2022
Realized gain	**(0.1)**	(2.9)	(1.8)	**(1.4)**	(5.7)
Unrealized (gain) loss - Senior Notes	**(16.8)**	(13.7)	16.8	**(15.6)**	45.9
Unrealized (gain) loss - Credit Facility	**(38.0)**	(134.8)	33.9	**(47.2)**	10.1
Unrealized loss (gain) - cross-currency swaps	**36.7**	133.2	(33.3)	**43.9**	(8.1)
Unrealized (gain) loss gain - other	**(2.7)**	0.1	1.3	**(1.8)**	1.5
Foreign Exchange (gain) loss	**(20.9)**	(18.1)	16.9	**(22.1)**	43.7

Foreign exchange for the three months and year ended December 31, 2023 resulted in a gain of $20.9 million and a gain of $22.1 million, respectively, compared to a gain of $18.1 million and a loss $43.7 million in the same periods of 2022 and a loss of $16.9 million for the three months ended September 30, 2023. The foreign exchange gains and losses are driven by the CAD/USD exchange rate applied to U.S. dollar denominated debt balances net of cross-currency swaps.

SEGMENT RESULTS

Strathcona has three operating segments:

- Cold Lake Thermal which includes three producing assets in the Cold Lake region of Northern Alberta: Lindbergh, Orion and Tucker;
- Lloydminster Heavy Oil which has multiple large oil-in-place reservoirs accessed through enhanced oil recovery techniques and thermal steam-assisted gravity drainage ("**SAGD**"), primarily located in Southwest Saskatchewan; and
- Montney which includes assets in the Northwest Alberta Kakwa and Grande Prairie regions and the Northeast British Columbia Groundbirch region.

All amounts not attributable to an operating segment are captured in "Corporate and Eliminations".

For the Three Months Ended	Cold Lake Thermal Segment			Lloydminster Heavy Oil Segment			Montney Segment			Corporate and Eliminations			Consolidated		
	Dec 31, 2023	Dec 31, 2022	Sept 30, 2023	**Dec 31, 2023**	Dec 31, 2022	Sept 30, 2023	**Dec 31, 2023**	Dec 31, 2022	Sept 30, 2023	**Dec 31, 2023**	Dec 31, 2022	Sept 30, 2023	**Dec 31, 2023**	Dec 31, 2022	Sept 30, 2023
Production and sales volumes															
Production volumes (boe/d)	**59,845**	49,792	58,179	**52,987**	56,960	51,482	**73,232**	36,619	37,800	**—**	—	—	**186,064**	143,371	147,461
Sales volumes (boe/d)	**60,027**	49,253	57,888	**51,100**	55,724	53,189	**73,232**	36,619	37,797	**—**	—	—	**184,360**	141,596	148,874
Segment revenues															
Oil and natural gas sales	**592.8**	492.1	671.1	**438.0**	465.0	490.2	**257.8**	168.9	139.3	**(1.0)**	(1.1)	(0.4)	**1,287.6**	1,124.9	1,300.2
Sales of purchased products	**—**	—	—	**—**	—	—	**—**	—	—	**11.3**	18.2	7.2	**11.3**	18.2	7.2
Blending costs	**(243.5)**	(222.9)	(201.7)	**(41.3)**	(43.2)	(36.8)	**—**	—	—	**—**	—	—	**(284.8)**	(266.1)	(238.5)
Purchased product	**—**	—	—	**—**	—	—	**—**	—	—	**(10.3)**	(17.1)	(6.8)	**(10.3)**	(17.1)	(6.8)
Oil and natural gas sales, net of blending[1]	**349.3**	269.2	469.4	**396.7**	421.8	453.4	**257.8**	168.9	139.3	**—**	—	—	**1,003.8**	859.9	1,062.1
Segment expenses															
Royalties	**73.8**	63.8	134.1	**41.7**	38.7	55.1	**19.4**	32.5	13.5	**—**	—	—	**134.9**	135.0	202.7
Production and operating - Energy	**39.6**	73.3	53.9	**31.4**	43.1	27.4	**1.5**	0.7	0.1	**—**	—	—	**72.5**	117.1	81.4
Production and operating - Non-energy	**44.9**	38.6	41.0	**50.6**	45.2	57.6	**37.8**	13.8	15.3	**—**	—	—	**133.3**	97.6	113.9
Transportation and processing	**18.7**	19.6	24.0	**65.4**	75.8	71.9	**51.6**	19.7	18.6	**—**	—	—	**135.7**	115.1	114.5
Field Operating Income[1]	**172.3**	73.9	216.4	**207.6**	219.0	241.4	**147.5**	102.2	91.8	**—**	—	—	**527.4**	395.1	549.6
Depletion, depreciation and amortization	**42.9**	27.5	39.2	**103.5**	92.5	104.8	**76.7**	21.7	23.8	**4.4**	2.7	3.8	**227.5**	144.4	171.6
Field Operating Earnings[1]	**129.4**	46.4	177.2	**104.1**	126.5	136.6	**70.8**	80.5	68.0	**(4.4)**	(2.7)	(3.8)	**299.9**	250.7	378.0
General and administrative	**—**	—	—	**—**	—	—	**—**	—	—	**24.5**	24.2	20.7	**24.5**	24.2	20.7
Other income	**—**	—	—	**—**	—	—	**—**	—	—	**0.1**	(1.5)	(0.9)	**0.1**	(1.5)	(0.9)
Interest expense	**—**	—	—	**—**	—	—	**—**	—	—	**51.6**	49.9	50.2	**51.6**	49.9	50.2
Finance costs	**—**	—	—	**—**	—	—	**—**	—	—	**21.6**	8.7	18.1	**21.6**	8.7	18.1
Operating Earnings[1]													**202.1**	169.4	289.9
(Gain) loss on risk management contracts - realized	**—**	—	—	**—**	—	—	**—**	—	—	**(19.5)**	15.8	56.1	**(19.5)**	15.8	56.1
(Gain) loss on risk management contracts - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**(109.6)**	61.3	209.7	**(109.6)**	61.3	209.7
Foreign exchange (gain) loss - realized	**—**	—	—	**—**	—	—	**—**	—	—	**(0.1)**	(2.9)	(1.8)	**(0.1)**	(2.9)	(1.8)
Foreign exchange (gain) loss - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**(20.8)**	(15.2)	18.7	**(20.8)**	(15.2)	18.7
Transaction related (recoveries) costs	**—**	—	—	**—**	—	—	**—**	—	—	**(1.3)**	6.0	3.5	**(1.3)**	6.0	3.5
Unrealized (gain) loss on Sable remediation fund	**—**	—	—	**—**	—	—	**—**	—	—	**(0.3)**	—	0.2	**(0.3)**	—	0.2
Deferred tax expense	**—**	—	—	**—**	—	—	**—**	—	—	**90.0**	42.2	44.6	**90.0**	42.2	44.6
Income (loss) and comprehensive income (loss)													**263.7**	62.2	(41.1)

(1) A non-GAAP financial measure which does not have a standardized meaning under IFRS; see "Specified Financial Measures" section of this MD&A.

For the Three Months Ended ($/boe)	Cold Lake Thermal Segment			Lloydminster Heavy Oil Segment			Montney Segment			Corporate and Eliminations			Consolidated		
	Dec 31, 2023	Dec 31, 2022	Sept 30, 2023	**Dec 31, 2023**	Dec 31, 2022	Sept 30, 2023	**Dec 31, 2023**	Dec 31, 2022	Sept 30, 2023	**Dec 31, 2023**	Dec 31, 2022	Sept 30, 2023	**Dec 31, 2023**	Dec 31, 2022	Sept 30, 2023
Segment revenues															
Oil and natural gas sales	**76.15**	75.96	92.81	**86.90**	85.01	94.79	**38.26**	50.13	40.06	**(0.06)**	(0.09)	(0.03)	**65.82**	73.44	81.88
Sales of purchased products	**—**	—	—	**—**	—	—	**—**	—	—	**0.67**	1.40	0.53	**0.67**	1.40	0.53
Blending costs	**(12.90)**	(16.55)	(4.67)	**(2.52)**	(2.73)	(2.13)	**—**	—	—	**—**	—	—	**(6.71)**	(7.52)	(4.36)
Purchased product	**—**	—	—	**—**	—	—	**—**	—	—	**(0.61)**	(1.31)	(0.50)	**(0.61)**	(1.31)	(0.50)
Oil and natural gas sales, net of blending[1]	**63.25**	59.41	88.14	**84.38**	82.28	92.66	**38.26**	50.13	40.06	**—**	—	—	**59.17**	66.01	77.55
Segment expenses															
Royalties	**13.36**	14.08	25.18	**8.87**	7.55	11.26	**2.88**	9.65	3.88	**—**	—	—	**7.95**	10.36	14.80
Production and operating - Energy	**7.17**	16.18	10.12	**6.68**	8.41	5.60	**0.22**	0.21	0.03	**—**	—	—	**4.27**	8.99	5.94
Production and operating - Non-energy	**8.13**	8.52	7.70	**10.76**	8.82	11.77	**5.61**	4.10	4.40	**—**	—	—	**7.86**	7.49	8.32
Transportation and processing	**3.39**	4.33	4.51	**13.91**	14.79	14.69	**7.66**	5.85	5.35	**—**	—	—	**8.00**	8.84	8.36
Field Operating Netback[1]	**31.20**	16.30	40.63	**44.16**	42.71	49.34	**21.89**	30.32	26.40	**—**	—	—	**31.09**	30.33	40.13
Depletion, depreciation and amortization	**7.77**	6.07	7.36	**22.02**	18.04	21.42	**11.38**	6.44	6.84	**0.26**	0.21	0.28	**13.41**	11.08	12.53
Field Operating Earnings Netback[1]	**23.43**	10.23	33.27	**22.15**	24.67	27.92	**10.51**	23.88	19.56	**(0.26)**	(0.21)	(0.28)	**17.68**	19.25	27.60
General and administrative	**—**	—	—	**—**	—	—	**—**	—	—	**1.44**	1.86	1.51	**1.44**	1.86	1.51
Other expense (income)	**—**	—	—	**—**	—	—	**—**	—	—	**0.01**	(0.12)	(0.07)	**0.01**	(0.12)	(0.07)
Interest expense	**—**	—	—	**—**	—	—	**—**	—	—	**3.04**	3.83	3.67	**3.04**	3.83	3.67
Finance costs	**—**	—	—	**—**	—	—	**—**	—	—	**1.27**	0.67	1.32	**1.27**	0.67	1.32
Operating Earnings [1]													**11.92**	13.01	21.17
Effective royalty rate (%)[1]	**21.1**	21.8	28.6	**10.5**	10.4	12.2	**7.5**	19.2	9.7				**13.4**	15.7	19.1

(1) A non-GAAP financial measure which does not have a standardized meaning under IFRS; see "Specified Financial Measures" section of this MD&A.

For the Year Ended	Cold Lake Thermal Segment		Lloydminster Heavy Oil Segment		Montney Segment		Corporate and Eliminations		Consolidated	
	December 31, 2023	December 31, 2022	**December 31, 2023**	December 31, 2022	**December 31, 2023**	December 31, 2022	**December 31, 2023**	December 31, 2022	**December 31, 2023**	December 31, 2022
Production and sales volumes										
Production volumes (boe/d)	**55,768**	46,552	**53,930**	33,975	**45,761**	33,877	**—**	—	**155,459**	114,404
Sales volumes (boe/d)	**55,766**	45,947	**54,393**	34,118	**45,761**	33,877	**—**	(414)	**155,920**	113,528
Segment revenues										
Oil and natural gas sales	**2,279.8**	2,358.6	**1,812.8**	1,331.4	**655.5**	672.8	**0.2**	(19.4)	**4,748.3**	4,343.4
Sales of purchased product	**—**	—	**—**	—	**—**	—	**46.3**	64.7	**46.3**	64.7
Blending costs	**(888.1)**	(878.6)	**(170.2)**	(178.3)	**—**	—	**—**	19.0	**(1,058.3)**	(1,037.9)
Purchased product	**—**	—	**—**	—	**—**	—	**(46.5)**	(64.3)	**(46.5)**	(64.3)
Oil and natural gas sales, net of blending[1]	**1,391.7**	1,480.0	**1,642.6**	1,153.1	**655.5**	672.8	**—**	—	**3,689.8**	3,305.9
Segment expenses										
Royalties	**323.3**	419.0	**175.1**	151.1	**58.5**	96.7	**—**	—	**556.9**	666.8
Production and operating - Energy	**198.4**	246.3	**120.5**	80.6	**3.4**	3.3	**—**	—	**322.3**	330.2
Production and operating - Non-energy	**173.9**	132.2	**216.3**	123.8	**83.8**	54.0	**—**	—	**474.0**	310.0
Transportation and processing	**80.4**	69.2	**293.7**	114.4	**108.8**	74.6	**—**	—	**482.9**	258.2
Acquired inventory	**—**	—	**—**	54.2	**—**	—	**—**	—	**—**	54.2
Field Operating Income[1]	**615.7**	613.3	**837.0**	629.0	**401.0**	444.2	**—**	—	**1,853.7**	1,686.5
Depletion, depreciation and amortization	**148.9**	120.8	**423.2**	191.2	**145.9**	72.6	**14.9**	11.1	**732.9**	395.7
Field Operating Earnings[1]	**466.8**	492.5	**413.8**	437.8	**255.1**	371.6	**(14.9)**	(11.1)	**1,120.8**	1,290.8
General and administrative	**—**	—	**—**	—	**—**	—	**91.9**	68.8	**91.9**	68.8
Other income	**—**	—	**—**	—	**—**	—	**(1.0)**	(5.3)	**(1.0)**	(5.3)
Interest expense	**—**	—	**—**	—	**—**	—	**206.2**	109.4	**206.2**	109.4
Finance costs	**—**	—	**—**	—	**—**	—	**75.3**	29.8	**75.3**	29.8
Operating Earnings[1]									**748.4**	1,088.1
Loss on risk management contracts - realized	**—**	—	**—**	—	**—**	—	**42.4**	278.6	**42.4**	278.6
(Gain) on risk management contracts - unrealized	**—**	—	**—**	—	**—**	—	**(112.0)**	(90.4)	**(112.0)**	(90.4)
Foreign exchange (gain) - realized	**—**	—	**—**	—	**—**	—	**(1.4)**	(5.7)	**(1.4)**	(5.7)
Foreign exchange (gain) loss - unrealized	**—**	—	**—**	—	**—**	—	**(20.7)**	49.4	**(20.7)**	49.4
Transaction related costs	**—**	—	**—**	—	**—**	—	**3.8**	11.2	**3.8**	11.2
Unrealized (gain) loss on Sable remediation fund	**—**	—	**—**	—	**—**	—	**(0.2)**	0.7	**(0.2)**	0.7
Share of equity investment income	**—**	—	**—**	—	**—**	—	**—**	(11.3)	**—**	(11.3)
Gain on step acquisitions of equity method investee	**—**	—	**—**	—	**—**	—	**—**	(132.1)	**—**	(132.1)
Loss on termination of lease liability	**—**	—	**—**	—	**—**	—	**—**	1.4	**—**	1.4
Current income tax (recovery)	**—**	—	**—**	—	**—**	—	**(46.9)**	—	**(46.9)**	—
Deferred tax expense (recovery)	**—**	—	**—**	—	**—**	—	**296.2**	(371.9)	**296.2**	(371.9)
Income and comprehensive income									**587.2**	1,358.2

(1) A non-GAAP financial measure which does not have a standardized meaning under IFRS; see "Specified Financial Measures" section of this MD&A.

For the Year Ended ($/boe)	Cold Lake Thermal Segment		Lloydminster Heavy Oil Segment		Montney Segment		Corporate and Eliminations		Consolidated	
	December 31, 2023	December 31, 2022	**December 31, 2023**	December 31, 2022	**December 31, 2023**	December 31, 2022	**December 31, 2023**	December 31, 2022	**December 31, 2023**	December 31, 2022
Segment revenues										
Oil and natural gas sales	**79.56**	98.31	**85.59**	98.51	**39.24**	54.41	**0.01**	(0.47)	**71.36**	87.36
Sales of purchased products	**—**	—	**—**	—	**—**	—	**0.81**	1.56	**0.81**	1.56
Blending costs	**(11.19)**	(10.06)	**(2.85)**	(5.91)	**—**	—	**—**	0.46	**(6.52)**	(7.60)
Purchased product	**—**	—	**—**	—	**—**	—	**(0.82)**	(1.55)	**(0.82)**	(1.55)
Oil and natural gas sales, net of blending[1]	**68.37**	88.25	**82.74**	92.60	**39.24**	54.41	**—**	—	**64.83**	79.77
Segment expenses										
Royalties	**15.88**	24.98	**8.82**	12.13	**3.50**	7.82	**—**	—	**9.78**	16.09
Production and operating - Energy	**9.75**	14.69	**6.07**	6.47	**0.20**	0.27	**—**	—	**5.66**	7.97
Production and operating - Non-energy	**8.54**	7.88	**10.90**	9.94	**5.02**	4.37	**—**	—	**8.33**	7.48
Transportation and processing	**3.95**	4.13	**14.79**	9.19	**6.51**	6.03	**—**	—	**8.49**	6.23
Acquired inventory	**—**	—	**—**	4.35	**—**	—	**—**	—	**—**	1.31
Field Operating Netback [1]	**30.25**	36.57	**42.16**	50.52	**24.01**	35.92	**—**	—	**32.57**	40.69
Depletion, depreciation and amortization	**7.32**	7.20	**21.32**	15.35	**8.74**	5.87	**0.26**	0.27	**12.88**	9.55
Field Operating Earnings Netback[1]	**22.93**	29.37	**20.84**	35.17	**15.27**	30.05	**(0.26)**	(0.27)	**19.69**	31.14
General and administrative	**—**	—	**—**	—	**—**	—	**1.61**	1.66	**1.61**	1.66
Other income	**—**	—	**—**	—	**—**	—	**(0.02)**	(0.13)	**(0.02)**	(0.13)
Interest expense	**—**	—	**—**	—	**—**	—	**3.62**	2.64	**3.62**	2.64
Finance costs	**—**	—	**—**	—	**—**	—	**1.32**	0.72	**1.32**	0.72
Operating Earnings [1]									**13.16**	26.25
Effective royalty rate (%)[1]	**23.2**	28.3	**10.7**	13.1	**8.9**	14.4			**15.1**	20.2

(1) A non-GAAP financial measure which does not have a standardized meaning under IFRS; see "Specified Financial Measures" section of this MD&A.

Cold Lake Thermal

Production at the Cold Lake Thermal segment for the three months ended December 31, 2023, increased to 59,845 boe per day from 49,792 boe per day compared to same quarter of 2022. The increase in production is primarily due to production brought on from new drills in the year and improved base production performance at the Company's Lindbergh and Orion properties.

For the year ended December 31, 2023, production increased to 55,768 boe per day from 46,552 boe per day in the same period of 2022. The increase is primarily due to new wells drilled as well as the addition of production from the Tucker property, acquired through the Stickney Amalgamation, which contributed approximately 18,400 bbl/d in 2023 compared to 15,900 bbl/d in the same period of 2022.

Oil and natural gas sales, net of blending, increased to $349.3 million ($63.25 per boe) during the three months ended December 31, 2023 compared to $269.2 million ($59.41 per boe) for the same quarter of 2022. The increase is primarily due to higher sales volumes, and a lower blend cost per boe due to decreased benchmark condensate pricing.

Oil and natural gas sales, net of blending, decreased to $1,391.7 million ($68.37 per boe) during the year ended December 31, 2023 compared to $1,480.0 million ($88.25 per boe) in the same period of 2022. The decrease is primarily due to reductions in benchmark commodity prices, partially offset by higher sales volumes.

The effective royalty rate for the three months and year ended December 31, 2023 decreased to 21.1% and 23.2%, respectively, from 21.8% and 28.3% in the same quarter of 2022 due to lower benchmark pricing. These changes are reflective of the movement in benchmark pricing in the respective periods.

Energy related production and operating costs for the three months and year ended December 31, 2023 decreased to $39.6 million ($7.17 per boe) and $198.4 million ($9.75 per boe), respectively, from $73.3 million ($16.18 per boe) and $246.3 million ($14.69 per boe) in the same periods of 2022. These decreases are primarily attributable to the lower price of natural gas and electricity in 2023, partially offset, for the year ended December 31, 2023, by costs associated with higher volumes from the Stickney Amalgamation and increased carbon taxes.

For the three months and year ended December 31, 2023, non-energy related production and operating costs increased to $44.9 million ($8.13 per boe) and $173.9 million ($8.54 per boe), respectively, from $38.6 million ($8.52 per boe) and $132.2 million ($7.88 per boe) in the same periods of 2022. These increases are primarily due to inflationary pressures and, for the year ended December 31, 2023, higher volumes from the Stickney Amalgamation.

For the three months ended December 31, 2023, transportation and processing decreased to $18.7 million ($3.39 per boe) from $19.6 million ($4.33 per boe) in the same quarter of 2022. The reduction is due to the utilization of pipeline take or pay make-up rights from prior periods.

Transportation and processing increased to $80.4 million ($3.95 per boe) for the year ended December 31, 2023 from $69.2 million ($4.13 per boe) during the same period of 2022. The increase is primarily due to increased production volumes.

Lloydminster Heavy Oil

Production for the Lloydminster Heavy Oil segment for the three months ended December 31, 2023, decreased to 52,987 boe per day from 56,960 boe per day as compared to same period of 2022. This decrease is primarily due to lower production volumes from properties acquired through the Serafina Acquisition, which contributed approximately 28,500 boe per day in the three months ended December 31, 2023 compared to approximately 32,800 boe per day in the same period of 2022.

Production for the year ended December 31, 2023 increased to 53,930 boe per day from 33,975 boe per day in the same period of 2022. The increase is primarily due to the addition of properties acquired through the Caltex Amalgamation and the Serafina Acquisition, which contributed approximately 40,700 boe per day for the year ended December 31, 2023 compared to approximately 21,300 boe per day for the same period of 2022.

Oil and natural gas sales, net of blending, decreased to $396.7 million ($84.38 per boe) during the three months ended December 31, 2023 compared to $421.8 million ($82.28 per boe) for the same period of 2022. The decrease is primarily due to lower benchmark commodity prices.

Oil and natural gas sales, net of blending, increased to $1,642.6 million ($82.74 per boe) during the year ended December 31, 2023 compared to $1,153.1 million ($92.60 per boe) for the same period in 2022. The increase on a dollar basis is primarily due to production from properties acquired through the Caltex Amalgamation and the Serafina Acquisition. On a per boe basis, the decrease is the result of lower benchmark commodity prices.

The reduction in benchmark commodity prices also impacted royalties. The effective royalty rate for the year ended December 31, 2023 decreased to 10.7% from 13.1% in the same period of 2022.

Energy related production and operating costs for the three months ended December 31, 2023 decreased to $31.4 million ($6.68 per boe) from $43.1 million ($8.41 per boe) for the same period in 2022. The decrease is primarily attributable to lower natural gas prices.

Energy related production and operating costs for the year ended December 31, 2023 increased to $120.5 million ($6.07 per boe) from $80.6 million ($6.47 per boe) for the same period in 2022. The increase is primarily attributable to higher production volumes from the addition of thermal properties acquired through the Serafina Acquisition; partially offset by reductions in electricity and natural gas prices.

Non-energy related production and operating costs for the three months and year ended December 31, 2023 increased to $50.6 million ($10.76 per boe) and $216.3 million ($10.90 per boe), respectively, from $45.2 million ($8.82 per boe) and $123.8 million ($9.94 per boe) in the same periods of 2022. The increases are primarily due to the incremental production from properties acquired through the Caltex Amalgamation, the Serafina Acquisition and inflationary pressures on maintenance and other services.

For the three months ended December 31, 2023, transportation and processing decreased to $65.4 million ($13.91 per boe) from $75.8 million ($14.79 per boe) in the same quarter of 2022. The decrease is primarily due to lower sales volumes from the legacy Serafina assets in the fourth quarter of 2023.

Transportation and processing increased to $293.7 million ($14.79 per boe) for the year ended December 31, 2023 from $114.4 million ($9.19 per boe) during the same period of 2022. The increase is primarily due to the addition of legacy Serafina and Caltex oil volumes which are primarily transported to their respective sales points by rail and truck resulting in higher transportation costs per barrel than legacy Strathcona heavy oil volumes which are transported by pipeline.

Acquired inventory represents the cost paid by Strathcona through the Serafina Acquisition for oil inventory in transit at the close date of the acquisition. These volumes were sold in the month following and recorded as sales with no associated gain or loss.

Montney

Production at the Company's Montney segment for the three months and year ended December 31, 2023 increased to 73,232 boe per day and 45,761 boe per day, respectively, from 36,619 boe per day and 33,877 boe per day in the same periods of 2022. These increases are primarily due to production from properties added through the Pipestone Acquisition, which was completed in the fourth quarter of 2023.

For the three months ended December 31, 2023, oil and natural gas sales increased to $257.8 million ($38.26 per boe) from $168.9 million ($50.13 per boe) in the same period of 2022. This increase was primarily due to the increased volumes added through the Pipestone Acquisition, partially offset by lower benchmark commodity prices.

For the year ended December 31, 2023, oil and natural gas sales decreased to $655.5 million ($39.24 per boe) from $672.8 million ($54.41 per boe) in the same period of 2022. This decrease was primarily driven by lower benchmark commodity prices, offset by increased production from the Pipestone Acquisition.

The reduction in benchmark commodity prices also impacted royalties. For the three months and year ended December 31, 2023, royalties as a percentage of sales decreased to 7.5% and 8.9%, respectively, from 19.2% and 14.4% in the same periods of 2022.

Non-energy related production and operating costs increased to $37.8 million ($5.61 per boe) for the three months ended December 31, 2023 from $13.8 million ($4.10 per boe) in the same quarter of 2022. The increase is primarily due to properties acquired through the Pipestone Acquisition.

Non-energy related production and operating costs increased to $83.8 million ($5.02 per boe) for the year ended December 31, 2023 from $54.0 million ($4.37 per boe) in the same period of 2022. The increase is primarily due to higher gas processing fees as a result of the Pipestone Acquisition as well as inflationary pressures on maintenance and other services.

Transportation and processing costs increased to $51.6 million ($7.66 per boe) for the three months ended December 31, 2023 from $19.7 million ($5.85 per boe) in the same quarter of 2022. For the year ended December 31, 2023, the transportation and processing cost increased to $108.8 million ($6.51 per boe) from $74.6 million ($6.03 per boe) in the same period of 2022. The increase in transportation and processing costs are primarily attributable to increased volumes added through the Pipestone Acquisition.

Corporate and Eliminations

Condensate produced from Strathcona's Montney segment economically offsets consumption at the Cold Lake Thermal and Lloydminster Heavy Oil segments. Strathcona utilizes Company production internally when it is economically beneficial to do so as compared to purchasing third party production. Average daily sales volumes, oil and natural gas sales and blending costs represent the elimination of these intersegment transactions.

CAPITAL RESOURCES

Bank Credit Facilities

Covenant-Based Revolving Credit Facility

As at December 31, 2023, the Company had a covenant-based revolving credit facility of $2.3 billion (December 31, 2022 - $2.0 billion) with a syndicate of Canadian, U.S. and international financial institutions (the "**Revolving Credit Facility**"). The Revolving Credit Facility was increased from $2.0 billion to $2.3 billion on October 3, 2023, concurrent with the Pipestone Acquisition.

The Revolving Credit Facility has a maturity date of February 27, 2026. There are no mandatory payments on the Revolving Credit Facility. Borrowings under the Revolving Credit Facility may be drawn and repaid from time to time by the Company in Canadian or U.S. dollars. In addition, the covenant-based Revolving Credit Facility is not a borrowing base facility and does not require annual or semi-annual reviews.

The Revolving Credit Facility bears interest at the applicable prime lending rate, base rate, bankers' acceptance or Secured Overnight Financing Rate ("**SOFR**") plus applicable margins. The applicable margin charged by the lenders is dependent on the Company's Senior Debt to Adjusted EBITDA ratio (as defined below) for the most recently completed quarter. The Revolving Credit Facility is guaranteed by the Company's subsidiaries, and is secured by a security interest in substantially all of the existing and future assets of the Company and its subsidiaries, including by way of a floating charge debenture granted by the Company and each of its subsidiaries.

As at December 31, 2023, the Company had letters of credit outstanding under the Revolving Credit Facility of $10.6 million (December 31, 2022 - $12.5 million).

Term Credit Facility

At December 31, 2022, the Company had a $700.0 million term loan with a syndicate of Canadian financial institutions (the "**Term Credit Facility**" and together with the Revolving Credit Facility, the "**Credit Facilities**"). The Term Credit Facility had a maturity date of February 29, 2024. Borrowings under the Term Credit Facility were fully advanced in August 2022 and amortization payments were made throughout 2023; the remaining balance of the Term Credit Facility was repaid on December 28, 2023, and commitments thereunder were cancelled.

Foreign Exchange Risk Management on U.S. Denominated Debt

Strathcona periodically borrows in U.S. dollars and concurrently enters into cross-currency interest rate swap contracts to take advantage of an interest rate arbitrage that results from the relationship between Canadian and U.S. dollar interest rates and forward foreign exchange curves.

Foreign currency risk associated with these borrowings is eliminated at the time of borrowing as cross-currency interest rate swap contracts fix the principal and interest payments due at maturity. The terms of the Credit Facilities allow the Canadian dollar equivalent of U.S. borrowings to exceed contracted amounts due to fluctuations in foreign exchange, provided that settlement amounts have been fixed upfront using cross-currency interest rate swap contracts. Debt on the balance sheet includes the Canadian dollar equivalent of U.S. borrowings translated at the period end exchange rate, which does not include the offsetting impact of cross-currency interest rate swaps. As at December 31, 2023 the cross-currency swap liability was $39.6 million (December 31, 2022 – $4.3 million asset) and total debt includes an unrealized gain of $41.3 million (December 31, 2022 – unrealized loss of $5.9 million) related to U.S. borrowings on the Credit Facilities. Unrealized gains or losses on U.S. borrowings and offsetting unrealized gains or losses on cross-currency swap assets are included in foreign exchange gains in the annual financial statements.

As at December 31, 2023, the Company had cross-currency interest rate swap contracts outstanding totaling.

Notional (US$)	Maturity Date	Contract Price
1,277.9 million	January 12, 2024	CAD/USD 1.3566

Financial Covenants

As at December 31, 2023, the Revolving Credit Facility had three financial covenants which are calculated quarterly (as set out below) in accordance with the credit agreement governing the Revolving Credit Facility (the "**Credit Agreement**").

(i) Total Debt to Adjusted EBITDA Ratio – All debt excluding the Financing Agreement (see Note 7 of the annual financial statements), capital leases and letters of credit constituting debt ("**Total Debt**"), each as defined in the Credit Agreement shall not exceed 4.0 times trailing 12-month net income before non-cash items, income taxes, interest expense and extraordinary and non-recurring losses, adjusted for material acquisitions or dispositions as if they occurred on the first day of the calculation period ("**Adjusted EBITDA**"). For the purposes of Adjusted EBITDA, lease payments are deducted from the calculation if a lease would have been considered an operating lease before the adoption of IFRS 16. Total Debt may include the value of the Company's undiscounted inactive abandonment and reclamation obligations for a material jurisdiction if the liability management ratio in that jurisdiction falls below the minimum maintenance level required under the Credit Agreement (1.0 in British Columbia and 2.0 in all other material jurisdictions). Liability management ratios are calculated by provincial regulators based on deemed asset and deemed liability values determined by the respective regulator, other than for British Columbia, which is calculated by the Company based on past practice of the BC Oil and Gas Commission.

(ii) Senior Debt to Adjusted EBITDA Ratio – Total Debt excluding permitted junior debt (e.g. Senior Notes), as defined in the Credit Agreement, shall not exceed 3.5 times trailing 12-month Adjusted EBITDA.

(iii) Interest Coverage Ratio – Trailing 12-month Adjusted EBITDA, shall not be less than 3.5 times cash interest expense ("**Interest Charges**"), as defined in the Credit Agreement.

As at December 31, 2023, the Company was in compliance with such financial covenants, which are summarized in the following table.

As at	December 31, 2023
Total Debt to Adjusted EBITDA Ratio (≤ 4.00)[1]	**1.44**
Senior Debt to Adjusted EBITDA Ratio (≤ 3.50)[1]	**1.09**
Interest Coverage Ratio (≥ 3.50)[1]	**8.22**

[1] See "Specified Financial Measures" section of this MD&A.

Senior Notes

As at December 31, 2023, Strathcona had $662.2 million (December 31, 2022 - $677.7 million) of senior unsecured notes outstanding, with an aggregate principal amount of US$500.0 million, due August 1, 2026 (the "**Senior Notes**"). The Senior Notes bear interest at 6.875% per annum, payable semi-annually in arrears on February 1 and August 1 of each year. The Senior Notes are redeemable at Strathcona's option, in whole or in part, at the following redemption prices.

Date	Price
August 1, 2023	**105.156 %**
August 1, 2024	**101.719 %**
August 1, 2025 and thereafter	**100.000 %**

The Senior Notes have no financial maintenance covenants.

Demand Letter of Credit Facility

As at December 31, 2023, the Company had a $100.0 million (December 31, 2022 - $60.0 million) demand letter of credit facility with a financial institution (the "**LC Facility**"). The LC Facility is supported by an account performance security guarantee issued by Export Development Canada in favour of the financial institution. The Company and its subsidiaries have indemnified Export Development Canada for the amount of any payment made by Export Development Canada to the financial institution pursuant to such account performance security guarantee; however, the obligations under such indemnity are unsecured. The letters of credit outstanding under the LC Facility do not impact the Company's borrowing capacity under the Revolving Credit Facility. As at December 31, 2023, the Company had letters of credit in the amount of $69.0 million (December 31, 2022 - $52.6 million) outstanding under the LC Facility.

CAPITAL MANAGEMENT AND LIQUIDITY

The Company's policy is to maintain a strong capital base for the objectives of maintaining financial flexibility, creditor and market confidence and to sustain the future development of the business. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. The Company considers its capital structure to include equity, long-term debt and working capital.

The Company generally relies on Funds from Operations and its Revolving Credit Facility to fund its capital requirements, including its working capital deficiency. Future liquidity depends primarily on Funds from Operations, availability on the Revolving Credit Facility and the ability to access debt and equity markets. All repayments of principal on the Revolving Credit Facility are due at its maturity date.

The availability under the Credit Facilities, net of cash, is summarized in the following table.

As at	**December 31, 2023**	December 31, 2022
Credit capacity	**2,300.0**	2,700.0
Credit Facilities debt at period end exchange rate	**(2,036.3)**	(2,408.3)
Unrealized (gain) loss on U.S. borrowings	**(41.3)**	5.9
Letters of credit outstanding	**(10.6)**	(12.5)
Availability	**211.8**	285.1
Cash	**—**	34.3
Availability under Credit Facilities, net of cash	**211.8**	319.4

The Company carries a working capital deficiency as part of its current capital structure. As at December 31, 2023, the working capital deficiency was $415.3 million (December 31, 2022 - $295.3 million). Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Company to meet its current and future obligations, to make scheduled principal and interest payments, to fund planned capital expenditures and to fund the other needs of the business for at least the next 12 months. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary. The Company's cash flow and the development of projects are dependent on factors discussed in the "Risk Factors" section of this MD&A.

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The oil and natural gas industry is cyclical and commodity prices can be volatile, both of which are expected to impact the Company's future revenue and profitability. A sustained decline in commodity prices and increased inflation and interest rates could adversely affect our business, financial condition and results of operations, liquidity and ability to meet financial commitments when due or delay planned capital expenditures.

The Company regularly prepares and updates budgets and forecasts in order to monitor its liquidity and ability to meet its financial obligations and commitments, including the ability to comply with the financial covenants under the Credit Facilities.

DECOMMISSIONING LIABILITY

At December 31, 2023, Strathcona's discounted decommissioning provision balance was $351.3 million (December 31, 2022 - $291.5 million) for future abandonment and reclamation of the Company's oil and natural gas properties. The increase is primarily attributed to changes in estimates of $64.6 million relating to a decrease in the credit-adjusted discount rate to 8.00% at December 31, 2023 from 9.60% at December 31, 2022.

During the year ended December 31, 2023, the Company incurred $37.9 million of decommissioning expenditures compared to $23.2 million in the same period of 2022.

CONTRACTUAL OBLIGATIONS AND OFF-BALANCE SHEET ARRANGEMENTS

Strathcona has contractual obligations in the normal course of business which may include purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, lease rental obligations, employee agreements and debt. These obligations are of a recurring, consistent nature and impact Strathcona's cash flows in an ongoing manner.

The following tables detail the undiscounted cash flows and contractual maturities of the Company's financial liabilities as at December 31, 2023.

	Total	**<1 year**	**1-3 years**	**4-5 years**	**> 5 years**
Revolving Credit Facility[1]	**2,077.6**	—	2,077.6	—	—
Senior Notes[2]	**798.7**	45.5	45.5	707.7	—
Accounts payable and accrued liabilities	**783.8**	783.8	—	—	—
Risk management contract liability	**145.0**	125.4	19.6	—	—
Lease and other obligations[3]	**610.2**	83.8	163.5	118.4	244.5
Total	**4,415.3**	1,038.5	2,306.2	826.1	244.5

(1) Contractual amount reflects contracted settlement price on cross-currency interest rate swap contracts and excludes future interest payments on borrowings.

(2) Amounts represent repayment of the Senior Notes ($662.2 million) and associated interest payments ($136.5 million) based on foreign exchange rate in effect on December 31, 2023.

(3) Amounts relate to undiscounted payments for lease and other obligations. The estimation of future cash payments related to other obligations are subject to forecast lending rates and timing of exercise of the repurchase option under the Financing Agreement, which is assumed to be exercised on January 1, 2029. See Note 7 of the annual financial statements.

As at December 31, 2023, the Company was committed to the following non-cancellable payments.

	Total	**< 1 year**	**1-3 years**	**4-5 years**	**> 5 years**
Transportation and processing commitments	**2,429.1**	303.9	547.0	468.8	1,109.4
Capital commitments	**101.0**	78.8	22.2	—	—
Other	**13.0**	4.3	6.4	2.3	—
Total	**2,543.1**	387.0	575.6	471.1	1,109.4

In the normal course of business, the Company is obligated to make future payments, including contractual obligations and non-cancellable commitments. The Company generally expects to meet these commitments through Funds from Operations and its Revolving Credit Facility. Strathcona does not maintain off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on the Company's financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources which are not disclosed in the notes to the annual financial statements.

SHARE CAPITAL

The authorized capital of the Company consists of an unlimited number of Common Shares and an unlimited number of preferred shares. Prior to the Pipestone Acquisition, the authorized capital of the Company consisted of an unlimited number of voting Class A and Class B common shares and an unlimited number of preferred shares. The Class A and Class B common shares were exchanged for Common Shares on October 3, 2023. No preferred shares have been issued by the Company as at December 31, 2023 (December 31, 2022 – nil).

The following table summarizes the number of shares outstanding as at March 26, 2024:

Share Class	Shares Outstanding at March 26, 2024
Preferred shares	nil
Common Shares	214,235,608
Balance outstanding	**214,235,608**

The Company had no outstanding securities which are convertible into Common Shares or preferred shares as at March 26, 2024.

RELATED PARTY TRANSACTIONS

For the year ended December 31, 2023, there were no related party transactions other than key management compensation.

Key management personnel of the Company include its officers and directors. For the year ended December 31, 2023, Strathcona recorded $13.4 million relating to compensation of key management personnel ($10.0 million for the year ended December 31, 2022).

On January 31, 2022, Strathcona exchanged $30.9 million of its shares in its investment in Stickney with an affiliate of WEF ("**WEF Fund II**") for shares of Caltex.

On January 31, 2022, Strathcona issued an unsecured, interest-bearing loan in the amount of $25.0 million to Stickney. The loan was extinguished upon the Caltex and Stickney Amalgamation.

On March 11, 2022, Strathcona acquired the remaining interests in Caltex and Stickney from WEF Fund II for share consideration valued at $295.8 million and $242.0 million respectively, and amalgamated with the entities.

Prior to the March 11, 2022 amalgamations, the Company provided management and administrative services to Caltex and Stickney. The fees received pursuant to this agreement from January 1, 2022 to March 11, 2022 totaled $0.6 million for Stickney and $1.3 million for Caltex.

RISK FACTORS

The Company's business is subject to numerous risks and uncertainties, any of which may adversely affect the Company's business and its financial results and results of its operations. For additional information refer to the “Risk Factors” section in our Annual Information Form for the year ended December 31, 2023, a copy of which may be accessed through the SEDAR+ website (www.sedarplus.ca).

Risks Relating to Strathcona’s Business

Strathcona’s exploration and production activities are concentrated in BC, Alberta and Saskatchewan where activity is highly competitive and includes a variety of different-sized companies. Strathcona is subject to a number of risks that are common to other organizations involved in the oil and gas industry. Such risks include finding and developing oil and gas reserves at economic costs, estimating amounts of recoverable reserves, marketability of oil and gas produced, fluctuations in commodity prices, access to capital, financial and liquidity risks and environmental and safety risks.

Strathcona is exposed to market risk to the extent that the demand for oil and gas produced by the Company exists within Canada and the United States. External factors beyond the Company’s control may affect the marketability of oil and gas produced. These factors include commodity prices and variations in the Canada-United States currency exchange rate which, in turn, responds to economic and political circumstances throughout the world. Oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals.

Exploration and production for oil and gas is capital intensive. Future capital expenditures may be financed in a variety of ways, including cash generated from operations, which fluctuates with changing commodity prices; borrowings, which exposes the Company to fluctuations in interest rates; and possible future equity offerings. Equity and debt capital are subject to market conditions, and availability and cost may increase or decrease from time to time.

General Risks

Oil and gas exploration and production can involve risks such as changes to the regulatory environment, litigation, cybersecurity breaches and competition for qualified personnel.

Climate Change Risks

Strathcona's operations emit greenhouse gases ("**GHG**") which may require us to comply with federal and/or provincial GHG emissions legislation. Climate change policy is evolving at regional, national, and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate its effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, climate change has been linked to long-term shifts in climate patterns and extreme weather conditions both of which pose the risk of causing operational difficulties.

SELECTED ANNUAL INFORMATION

	Years Ended December 31,		
($ millions, unless otherwise indicated)	**2023**	2022	2021
Oil and natural gas sales	**4,748.3**	4,343.4	1,572.3
Net income (loss)	**587.2**	1,358.2	264.5
Net income (loss) per share	**2.94**	0.63	0.15
Total assets	**10,496.9**	9,164.5	3,838.8
Total non-current liabilities	**4,103.1**	3,788.3	1,090.6

SUMMARY OF QUARTERLY RESULTS

	2023				2022			
($ millions, unless otherwise indicated)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Operating results (boe/d)								
Average production volumes	**186,064**	147,461	143,778	144,160	143,371	119,829	111,153	82,535
Average sales volumes	**184,360**	148,874	143,239	146,877	141,595	119,992	110,430	81,357
Financial Results								
Oil and natural gas sales	**1,287.6**	1,300.2	1,112.8	1,047.7	1,124.9	1,112.6	1,331.5	774.4
Net Income (loss)	**263.7**	(41.1)	274.1	90.5	62.2	606.3	349.7	340.0
Net income (loss) per share	**1.23**	(0.02)	0.13	0.04	0.03	0.28	0.16	0.17
Cash flow from operating activities	**570.0**	430.5	343.1	181.1	482.2	373.5	391.9	207.7
Operating Earnings(1)	**202.1**	289.9	201.4	55.0	169.4	284.3	405.0	229.4
Funds from Operations(1)	**470.8**	425.3	389.2	276.9	308.1	322.9	393.4	209.5
Free Cash Flow(1)	**150.8**	158.0	152.6	36.1	75.1	157.1	255.2	102.4
Field Operating Income(1)	**527.4**	549.6	460.8	315.9	395.1	432.4	538.2	320.8
Field Operating Netback ($/boe)(1)	**31.09**	40.13	35.35	23.82	30.33	39.16	53.55	43.81
Capital expenditures	**307.8**	260.2	231.7	228.7	228.5	157.5	136.8	98.1
Decommissioning expenditures	**13.8**	7.1	4.9	12.1	4.5	8.3	1.4	9.0
Total assets	**10,496.9**	9,588.9	9,451.2	9,289.5	9,164.5	9,416.3	6,091.0	6,047.4
Total debt	**2,665.0**	2,787.6	2,898.2	3,041.7	3,044.1	3,545.9	1,213.4	1,472.5
Total equity	**5,327.1**	4,526.4	4,567.5	4,292.7	4,202.2	4,088.9	3,594.6	3,269.6
Common shares outstanding, end of period	**214.2**	2,186.7	2,186.7	2,186.5	2,186.5	2,186.6	2,186.6	2,185.8

(1) A non-GAAP measure which does not have a standardized meaning under IFRS; see "Specified Financial Measures" section of this MD&A.

Over the past eight quarters, the Company's oil and natural gas sales have fluctuated due to the acquisitions as described in the “Description of Business” section of this MD&A and Note 4 of the annual financial statements, volatility in the crude oil, condensate and natural gas benchmark prices, changes in production and fluctuations in corporate oil price differentials. The Company's production has fluctuated due to acquisitions and dispositions, changes in its development capital spending levels and natural declines.

Net income (loss) has fluctuated over the past eight quarters primarily due to the acquisitions as described in the “Description of Business” section of this MD&A and Note 4 of the annual financial statements, changes in Funds from Operations, unrealized gains and losses from risk management contracts, which fluctuate with changes in forward market prices and foreign exchange rates, foreign exchange gains and losses associated with the Company’s Senior Notes, fluctuations in natural gas and power pricing and the associated impact on energy-related production and operating costs, inflationary pressure and fluctuations in deferred tax expense or recovery.

Capital expenditures and total assets have fluctuated throughout the past eight quarters due to changes in the Company's development capital spending levels which vary based on a number of factors, including the prevailing commodity price environment and the acquisitions as described in the “Description of Business” section of this MD&A and Note 4 of the annual financial statements.

SPECIFIED FINANCIAL MEASURES

This MD&A makes reference to certain financial measures and ratios, including “Oil and natural gas sales, net of blending”, “Bitumen blend per bbl”, “Heavy oil, blended and raw per bbl”, “Effective royalty rate”, “Field Operating Income”, “Field Operating Netback”, “Funds from Operations”, “Free Cash Flow”, and “Operating Earnings”, which are not recognized measures under generally accepted accounting principles (“**GAAP**”) and do not have a standardized meaning prescribed by IFRS. Accordingly, the Company’s use of these terms may not be comparable to similarly defined measures presented by other companies. Management uses the terms “Field Operating Income”, “Field Operating Netback”, “Operating Earnings”, “Funds from Operations” and “Free Cash Flow” for its own performance measures and to provide shareholders and potential investors with a measurement of the Company’s efficiency and its ability to generate the cash necessary to fund a portion of its future growth expenditures or to repay debt. Investors are cautioned that the specified financial measures should not be construed as an alternative to net income determined in accordance with GAAP as an indication of the Company’s performance.

Non-GAAP Financial Measures and Ratios

Non-GAAP financial measures and ratios are used internally by management to assess the performance of the Company. They also provide investors with meaningful metrics to assess the Company's performance compared to other companies in the same industry. However, the Company's use of these terms may not be comparable to similarly defined measures presented by other companies. Investors are cautioned that these measures should not be construed as an alternative to financial measures determined in accordance with GAAP and these measures should not be considered to be more meaningful than GAAP measures in evaluating the Company's performance.

The term “**Oil and natural gas sales, net of blending**” is calculated by deducting sales of purchased product and blending costs from oil and natural gas sales and sales of purchased product. Management uses this metric to isolate the revenue associated with the Company's production after accounting for the unavoidable cost of blending. A quantitative reconciliation of Oil and natural gas sales, net of blending to the most directly comparable GAAP financial measure, Oil and natural gas sales, is contained under the heading “Revenue and Realized Prices - Oil and Natural Gas Sales Net of Blending” and “Segment Results” of this MD&A.

Oil and natural gas sales, net of blending, is also reflected on a per boe basis calculated using sales volumes. Management also calculates “**Bitumen blend per bbl**” and “**Heavy oil, blended and raw per bbl**” by deducting the associated blending cost from sales and dividing by the respective sales volume. This ratio is useful to management when analyzing realized pricing against benchmark commodity prices.

The term **“Effective royalty rate”** is calculated by dividing royalties by oil and natural gas sales, net of blending. This metric allows management to analyze the movement of royalty expenses in relation to realized and benchmark commodity prices.

“**Field Operating Income**” and “**Field Operating Netback**” are common metrics used in the oil and natural gas industry to assess the profitability and efficiency of the Company's field operations.

"**Field Operating Earnings**" and "**Field Operating Earnings Netback**" are metrics used to assess the profitability of field operations inclusive depletion, depreciation and amortization. Management finds this metric useful as it provides a full-cycle profitability measure at the field level that accounts for the capital intensive nature of the Company’s operations.

The following table reconciles “Field Operating Income”, “Field Operating Earnings”, “Field Operating Netback” and “Field Operating Earnings Netback” to the nearest GAAP measure.

	Three Months Ended			**Year Ended**	
($ millions, unless otherwise indicated)	**December 31, 2023**	December 31, 2022	September 30, 2023	**December 31, 2023**	December 31, 2022
Oil and natural gas sales	**1,287.6**	1,124.9	1,300.2	**4,748.3**	4,343.4
Sales of purchased products	**11.3**	18.2	7.2	**46.3**	64.7
Purchased product	**(10.3)**	(17.1)	(6.8)	**(46.5)**	(64.3)
Blending costs	**(284.8)**	(266.1)	(238.5)	**(1,058.3)**	(1,037.9)
Oil and natural gas sales, net of blending	**1,003.8**	859.9	1,062.1	**3,689.8**	3,305.9
Royalties	**134.9**	135.0	202.7	**556.9**	666.8
Production and operating	**205.8**	214.7	195.3	**796.3**	640.2
Transportation and processing	**135.7**	115.1	114.5	**482.9**	258.2
Acquired inventory	**—**	—	—	**—**	54.2
Field Operating Income	**527.4**	395.1	549.6	**1,853.7**	1,686.5
Depletion, depreciation and amortization	**227.5**	144.4	171.6	**732.9**	395.7
Field Operating Earnings	**299.9**	250.7	378.0	**1,120.8**	1,290.8
Field Operating Netback ($/boe)	**31.09**	30.33	40.13	**32.57**	40.69
Field Operating Earnings Netback ($/boe)	**17.68**	19.25	27.60	**19.69**	31.14

"**Operating Earnings**" is considered a key financial metric for evaluating the profitability of Strathcona's principal business and is derived from income (loss) and comprehensive income (loss) adjusted for amounts which are considered non-recurring or not directly attributable to the Company's operations.

"**Funds from Operations**" is used by management to analyze operating performance and provides an indication of the funds generated by Strathcona's principal business to either fund operating activities, re-invest to either maintain or grow the business or make debt repayments. Funds from Operations is derived from income (loss) and comprehensive income (loss) adjusted for non-cash items and transaction costs.

"**Free Cash Flow**" indicates funds available for deleveraging, funding future growth, or, at some point in the future, shareholder returns. Free Cash Flow is derived from income (loss) and comprehensive income (loss) adjusted for non-cash items, transaction costs, capital expenditures and decommissioning costs.

A quantitative reconciliation of Operating Earnings, Funds from Operations and Free Cash Flow to the most directly comparable GAAP financial measure, income (loss) and comprehensive income (loss), is set forth below.

	Three Months Ended				**Year Ended**
($ millions, unless otherwise indicated)	**December 31, 2023**	September 30, 2023	June 30, 2023	March 31, 2023	**December 31, 2023**
Income (loss) and comprehensive income (loss)	**263.7**	(41.1)	274.1	90.5	**587.2**
(Gain) loss on risk management contracts	**(129.1)**	265.8	(142.1)	(64.2)	**(69.6)**
Foreign exchange (gain) loss	**(20.9)**	16.9	(12.2)	(5.9)	**(22.1)**
Transaction related (recoveries) costs	**(1.3)**	3.5	0.4	1.2	**3.8**
Unrealized (gain) loss on Sable remediation fund	**(0.3)**	0.2	0.1	(0.2)	**(0.2)**
Current income tax recovery	**—**	—	—	(46.9)	**(46.9)**
Deferred tax expense	**90.0**	44.6	81.1	80.5	**296.2**
Operating Earnings	**202.1**	289.9	201.4	55.0	**748.4**
Depletion, depreciation and amortization	**227.5**	171.6	170.7	163.1	**732.9**
Finance costs	**21.6**	18.1	17.8	17.8	**75.3**
Decommissioning government grant	**—**	—	—	(0.3)	**(0.3)**
Current income tax recovery	**—**	—	—	46.9	**46.9**
Gain (loss) on risk management contracts - realized	**19.5**	(56.1)	(0.4)	(5.4)	**(42.4)**
Foreign exchange gain (loss) - realized	**0.1**	1.8	(0.3)	(0.2)	**1.4**
Funds from Operations	**470.8**	425.3	389.2	276.9	**1,562.2**
Capital expenditures	**(306.2)**	(260.2)	(231.7)	(228.7)	**(1,026.8)**
Decommissioning costs	**(13.8)**	(7.1)	(4.9)	(12.1)	**(37.9)**
Free Cash Flow	**150.8**	158.0	152.6	36.1	**497.5**

($ millions, unless otherwise indicated)	Three Months Ended December 31, 2022	September 30, 2022	June 30, 2022	March 31, 2022	Year Ended December 31, 2022
Income and comprehensive income	62.2	606.3	349.6	340.1	1,358.2
Loss (gain) on risk management contracts	77.1	(183.3)	36.7	257.7	188.2
Foreign exchange (gain) loss	(18.1)	50.0	16.8	(5.0)	43.7
Transaction related costs	6.0	2.3	1.6	1.3	11.2
Unrealized loss on Sable remediation fund	—	—	0.3	0.4	0.7
Share of equity investment income	—	—	—	(11.3)	(11.3)
Gain on step acquisitions of equity method investee	—	—	—	(132.1)	(132.1)
Loss on termination of lease liability	—	—	—	1.4	1.4
Deferred tax expense (recovery)	42.2	(191.0)	—	(223.1)	(371.9)
Operating Earnings	169.4	284.3	405.0	229.4	1,088.1
Depletion, depreciation and amortization	144.4	96.5	96.5	58.3	395.7
Finance costs	8.7	8.3	6.7	6.1	29.8
Decommissioning government grant	(1.5)	(1.2)	(1.3)	(1.0)	(5.0)
Gain on termination of lease liability	—	—	—	(1.8)	(1.8)
(Loss) on risk management contracts - realized	(15.8)	(68.1)	(113.2)	(81.5)	(278.6)
Foreign exchange gain (loss) - realized	2.9	3.1	(0.3)	—	5.7
Funds from Operations	308.1	322.9	393.4	209.5	1,233.9
Capital expenditures	(228.5)	(157.5)	(136.8)	(98.1)	(620.9)
Decommissioning costs	(4.5)	(8.3)	(1.4)	(9.0)	(23.2)
Free Cash Flow	75.1	157.1	255.2	102.4	589.8

Previously, the Company deducted transaction costs in the determination of free cash flow. The deduction of transaction costs has been removed from the calculation as they are non-recurring in nature and management uses the free cash flow measure as an indication of the cash generating ability from the Company's ongoing operations. The following table reconciles the previously disclosed free cash flow measure to that presented in this MD&A:

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2023**	September 30, 2023	June 30, 2023	March 31, 2023	Year Ended **December 31, 2023**
Free Cash Flow	**150.8**	158.0	152.6	36.1	**497.5**
Transaction related recoveries (costs)	**1.3**	(3.5)	(0.4)	(1.2)	**(3.8)**
Free Cash Flow, previously reported	**152.1**	154.5	152.2	34.9	**493.7**

($ millions, unless otherwise indicated)	Three Months Ended December 31, 2022	September 30, 2022	June 30, 2022	March 31, 2022	Year Ended December 31, 2022
Free Cash Flow	75.1	157.1	255.2	102.4	589.8
Transaction related costs	(6.0)	(2.3)	(1.6)	(1.3)	(11.2)
Free Cash Flow, previously reported	69.1	154.8	253.6	101.1	578.6

Supplementary Financial Measures

The terms "Production and operating – Energy" and "Production and operating – Non-energy" are supplementary financial measures as they refer to portions of production and operating expenses. Non-energy operating expenses reflect the cost of operating activities relating to the production of resources. Energy operating expenses reflect the cost of gas and propane fuel, utilities and carbon tax incurred to operate facilities.

Energy and Non-energy production and operating expenses are also reflected on a per boe basis calculated using sales volumes.

The term “Crown royalties”, “Freehold royalties” and “Gross over-riding royalties” are supplementary financial measures as they refer to portions of royalty expenses. Crown royalties reflect the cost of royalties paid for production on land where petroleum oil and natural gas rights are owned by government bodies. Freehold royalties reflect the cost of royalties paid for production on land where petroleum oil and natural gas rights are owned by private individuals or entities. Contingent gross over-riding royalties reflect the cost of royalties paid to third parties when the WCS heavy oil benchmark exceeds US$60.00/bbl.

The term “Transportation expense” and “Processing expense” are supplementary financial measures as they refer to portions of transportation and processing expenses. Transportation expenses reflect the cost of transporting oil and natural gas to the sales point. Processing expenses reflect costs incurred to refine produced volumes to meet sales specifications.

The term “Depletion expense” and “Depreciation expense” are supplementary financial measures as they refer to portions of depletion, depreciation and amortization expenses. Depletion expenses reflect the cost of development of oil and natural gas reserves. Depreciation expense reflects the cost of a fixed asset over its expected useful life.

Financial Covenant Calculations

Total Debt and Senior Debt are defined in the Credit Agreement for financial covenant purposes, and are calculated as follows.

($ millions, unless otherwise indicated)	**As at December 31, 2023**
Revolving Credit Facility	**2,036.3**
Unrealized gain (loss) on SOFR loans	**41.3**
Senior Debt	**2,077.6**
Senior Notes	**662.2**
Total Debt	**2,739.8**

Adjusted EBITDA is defined in the Credit Agreement for financial covenant purposes, and is calculated on a trailing 12-month basis, as follows.

($ millions, unless otherwise indicated)	**Trailing 12-months ended December 31, 2023**
Net income	**587.2**
Adjusted for	
Interest and finance costs	**281.5**
Unrealized gain on commodity contracts	**(112.0)**
Depletion, depreciation, amortization and impairment	**732.9**
Unrealized foreign exchange gain	**(20.7)**
Unrealized gain on Sable remediation fund	**(0.2)**
Income tax expense	**249.3**
ARO government grants	**(0.3)**
IFRS 16 adjustment	**(28.3)**
EBITDA from Pipestone assets	**207.5**
Non-recurring losses	**3.8**
Adjusted EBITDA	**1,900.7**

Interest Charges are defined in the Credit Agreement for financial covenant purposes and are calculated on a trailing 12-month basis, as follows.

($ millions, unless otherwise indicated)	Trailing 12-months ended December 31, 2023
Interest on debt	**206.2**
Other adjustments[1]	**25.0**
Interest Charges	**231.2**

(1) Other adjustments include interest on finance leases, as defined in the Credit Agreement, and interest adjustments related to material acquisitions.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may results in actual results or changes to estimates that differ materially from current estimates. The Company's use of estimates and judgements in preparing the consolidated financial statements are discussed in note 2 of the consolidated financial statements for the year ended December 31, 2023.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures ("**DC&P**"), as defined in National Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings* ("**NI 52-109**"), are designed to provide reasonable assurance that information required to be disclosed in the Company's annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified under securities legislation and include controls and procedures designed to ensure that information required to be so disclosed is accumulated and communicated to management, including the President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer of Strathcona evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's DC&P as at December 31, 2023. Based on that evaluation, the President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer concluded that Strathcona's DC&P were effective as at December 31, 2023.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

As of December 31, 2023, Strathcona conducted an internal evaluation of the effectiveness of disclosure controls and procedures as defined in Canada by National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"). Based on that evaluation, the President and Chief Executive Officer and the Senior Vice President and Chief Financial Officer concluded that the disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that Strathcona files or submits under securities legislation is recorded, processed, summarized, and reported, within the time periods specified in the rules and forms therein. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that the information required to be disclosed by Strathcona in the reports that it files or submits under securities legislation is accumulated and communicated to Strathcona's Management, including the executive leadership team, as appropriate to allow timely decisions regarding the required disclosure.

Internal Control over Financial Reporting ("ICFR") is a set of processes designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized, and facilitate the preparation of relevant, reliable, and timely information. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Management has assessed the effectiveness of Strathcona's ICFR as defined in Canada by NI 52-109. The assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that Strathcona's ICFR was effective as of December 31, 2023. No changes were made to Strathcona's ICFR during the year ended December 31, 2023 that have materially affected, or are reasonably likely to materially affect, the ICFR.

ADVISORIES REGARDING OIL & GAS INFORMATION

This MD&A contains various references to the abbreviation "**boe**" which means barrels of oil equivalent. All boe conversions in this MD&A are derived by converting gas to oil at the ratio of six thousand cubic feet ("**mcf**") of natural gas to one barrel ("**bbl**") of crude oil. Boe may be misleading, particularly if used in isolation. A boe conversion rate of 1 bbl : 6 mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio of oil compared to natural gas based on currently prevailing prices is significantly different than the energy equivalency ratio of 1 bbl : 6 mcf, utilizing a conversion ratio of 1 bbl : 6 mcf may be misleading as an indication of value. References to "liquids" in this MD&A refer to, collectively, bitumen, heavy oil, condensate and light oil (comprised of condensate and light oil) and other natural gas liquids ("**NGL**") (comprised of ethane, propane and butane only).

National Instruments 51-101 - *Standards of Disclosure for Oil and Gas Activities* includes condensate within the natural gas liquids product type. The Company has disclosed condensate as combined with light oil and separately from other natural gas liquids in this MD&A since the price of condensate as compared to other natural gas liquids is currently significantly higher and the Company believes that this presentation provides a more accurate description of its operations and results therefrom. References to "oil and condensate" in this MD&A refer to, collectively, light and medium crude oil, heavy crude oil, bitumen and natural gas liquids. References to "natural gas" in this MD&A refer to conventional natural gas.

The Company's annual and quarterly average daily production volumes for 2023 and 2022, and the references to "natural gas", "crude oil" and "condensate", reported in this MD&A consist of the following product types, as defined in NI 51-101 and using a conversion ratio of 6 mcf : 1 bbl where applicable:

	Three Months Ended				Year Ended
	December 31, 2023	September 30, 2023	June 30, 2023	March 31, 2023	**December 31, 2023**
Heavy crude oil (bbl/d)	**52,736**	51,256	53,470	57,443	**53,707**
Light and medium crude oil (bbl/d)	**580**	600	674	719	**642**
Total crude oil (bbl/d)	**53,316**	51,856	54,144	58,162	**54,349**
Bitumen (bbl/d)	**59,845**	58,179	53,825	51,097	**55,768**
NGLs (bbl/d)	**30,509**	17,365	17,707	15,851	**20,389**
Total liquids (bbl/d)	**143,670**	127,400	125,676	125,110	**130,506**
Conventional natural gas (mcf/d)	**254,361**	120,366	108,612	114,304	**149,715**
Total (boe/d)	**186,064**	147,461	143,778	144,160	**155,459**

	Three Months Ended				Year Ended
	December 31, 2022	September 30, 2022	June 30, 2022	March 31, 2022	December 31, 2022
Heavy crude oil (bbl/d)	56,768	37,693	24,713	15,065	33,685
Light and medium crude oil (bbl/d)	871	1,389	526	434	808
Total crude oil (bbl/d)	57,639	39,082	25,239	15,499	34,493
Bitumen (bbl/d)	49,792	50,951	51,040	34,207	46,552
NGLs (bbl/d)	16,294	12,881	16,489	14,233	14,974
Total liquids (bbl/d)	123,725	102,914	92,768	63,939	96,019
Conventional natural gas (mcf/d)	117,878	101,491	110,310	111,576	110,308
Total (boe/d)	143,371	119,829	111,153	82,535	114,404

FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking information within the meaning of applicable securities laws. The forward-looking information in this MD&A is based on Strathcona's current internal expectations, estimates, projections, assumptions and beliefs. Such forward-looking information is not a guarantee of future performance and involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Company believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable as of the time of such information, but no assurance can be given that these factors, expectations and assumptions will prove to be correct, and such forward-looking information included in this MD&A should not be unduly relied upon.

The use of any of the words “expect”, “anticipate”, “estimate”, “objective”, “ongoing”, “may”, “will”, “project”, “believe”, “depends”, “could” and similar expressions are intended to identify forward-looking information. In particular, but without limiting the generality of the foregoing, this MD&A contains forward-looking information pertaining to the following: the Company’s business strategy and future plans; the Company's 2024 production and capital spending guidance; the Company’s use of hedging arrangements; the Company’s ability to meet current and future obligations, including making scheduled principal and interest payments and to fund the other needs of the business; future liquidity and financial capacity; anticipated proceeds from financial instruments, including commodity contracts; sources of funding for the Company’s capital program and the terms of Strathcona’s future contractual obligations, including its obligations under the Credit Agreement and Senior Notes and oil and natural gas prices and differentials.

All forward-looking information reflects Strathcona’s beliefs and assumptions based on information available at the time the applicable forward-looking information is disclosed and in light of the Company’s current expectations with respect to such things as: the success of Strathcona’s operations and growth and expansion projects; expectations regarding production growth, future well production rates and reserve volumes; expectations regarding Strathcona's capital program; the outlook for general economic trends, industry trends, prevailing and future commodity prices, foreign exchange rates and interest rates; prevailing and future royalty regimes and tax laws; future well production rates and reserve volumes; fluctuations in energy prices based on worldwide demand and geopolitical events; the impact of inflation; the integrity and reliability of Strathcona’s assets; decommissioning obligations; Strathcona’s ability to comply with its financial covenants; and the governmental, regulatory and legal environment. In addition, certain forward-looking information with respect to the Company's 2024 capital budget assumes commodity prices and exchange rates of: US$80 / bbl WTI, assuming a US$15.75 / bbl WCS-WTI differential, 0.73 USD-CAD and C$3.22 / mcf AECO. Management believes that its assumptions and expectations reflected in the forward-looking information contained herein are reasonable based on the information available on the date such information is provided and the process used to prepare the information. However, it cannot assure readers that these expectations will prove to be correct.

The forward-looking information included in this MD&A is not a guarantee of future performance and involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information, including, without limitation: changes in commodity prices; changes in the demand for or supply of Strathcona’s products; the continued impact, or further deterioration, in global economic and market conditions, including from inflation and/or certain geopolitical conflicts, such as the ongoing Russia/Ukraine conflict, the conflict in the Middle East, and other heightened geopolitical risks and the ability of the Company to carry on operations as contemplated in light of the foregoing; determinations by the Organization of the Petroleum Exporting Countries and other countries as to production levels; unanticipated operating results or production declines; changes in tax or environmental laws, climate change, royalty rates or other regulatory matters; changes in Strathcona’s development plans or by third party operators of Strathcona’s properties; competition from other producers; inability to retain drilling rigs and other services; failure to realize the anticipated benefits of the Company’s acquisitions; incorrect assessment of the value of acquisitions; delays resulting from or inability to obtain required regulatory approvals; increased debt levels or debt service requirements; inflation; changes in foreign exchange rates; inaccurate estimation of Strathcona’s oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets or other sources of capital; increased costs; a lack of adequate insurance coverage; the impact of competitors; and the other factors discussed under the “Risk Factors” section in this MD&A and in the Company's Annual Information Form for the year ended December 31, 2023, a copy of which is available under the Company's profile on SEDAR+ at www.sedarplus.ca.

The purpose of the capital expenditure guidance is to assist readers in understanding Strathcona's expected and targeted financial position and performance, and this information may not be appropriate for other purposes.

The foregoing risks should not be construed as exhaustive. The forward-looking information contained in this MD&A speaks only as of the date of this MD&A and Strathcona does not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws. Any forward-looking information contained herein is expressly qualified by this cautionary statement.

ADDITIONAL INFORMATION

Additional information about Strathcona, including Strathcona's Annual Information Form for the year ended December 31, 2023, can be found at: www.sedarplus.ca and www.strathconaresources.com.

STRATHCONA RESOURCES LTD

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2023 AND 2022

Deloitte.

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Independent Auditor's Report

To the Shareholders and Board of Directors of Strathcona Resources Ltd.

Opinion

We have audited the consolidated financial statements of Strathcona Resources Ltd., (the “Company”), which comprise the consolidated statements of financial position as at December 31, 2023 and 2022 , and the consolidated statements of income and comprehensive income, changes in equity and cash flows for the years then ended, and notes to the consolidated financial statements, including material accounting policy information (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2023, and 2022, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the *Auditor’s Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matter

A key audit matter is a matter that, in our professional judgment, was of most significance in our audit of the financial statements for the year ended December 31, 2023. This matter was addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on this matter.

Property Plant and Equipment – Oil and natural gas properties — Refer to Notes 3 and 5 to the financial statements.

Key Audit Matter Description:

The Company’s property, plant and equipment includes oil and natural gas properties. Oil and natural gas properties, including related facilities are depleted using the unit-of-production method (“depletion”) based on total estimated proved plus probable reserves. The Company engages independent reserve engineers to estimate oil and natural gas reserves using estimates, assumptions and engineering data.

The development of the Company's proved plus probable oil and natural gas reserves that are used to determine depletion requires management to make significant estimates and assumptions related to future oil and natural gas prices, reserves, and future development costs.

Given the significant judgments made by management related to oil and natural gas prices, reserves, and future development costs, these estimates and assumptions are subject to a high degree of estimation uncertainty. Auditing these estimates and assumptions required auditor judgment in applying audit procedures and in evaluating the results of those procedures.

How the Key Audit Matter Was Addressed in the Audit:

Our audit procedures related to future oil and natural gas prices, reserves, and future development costs used to measure oil and natural gas properties, including related facilities, included the following, among others:

- Evaluated oil and natural gas prices by independently developing a reasonable range of forecasts based on reputable third-party forecasts and market data and comparing those to the oil and natural gas prices selected by management.
- Evaluated the Company's independent reserve engineers by examining reports and assessing their scope of work and findings and assessing the competence, capability and objectivity by evaluating their relevant professional qualifications and experience.
- Evaluated the reasonableness of reserves by testing the source financial information underlying the reserves and comparing the reserve volumes to historical production volumes.
- Evaluated the reasonableness of future development costs by testing the source financial information underlying the estimate, comparing future development costs to historical results, and evaluating whether they are consistent with evidence obtained in other areas of the audit.

Other Information

Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis
- The information, other than the financial statements and our auditor's report thereon, in the Annual Report.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon. In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

We obtained Management's Discussion and Analysis and the Annual Report prior to the date of this auditor's report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor's report. We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor’s report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor’s report is Mandeep Singh.

/s/ Deloitte LLP

Chartered Professional Accountants
Calgary, Alberta
March 26, 2024

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
Cdn$ millions

As at	Note	December 31, 2023	December 31, 2022
Assets			
Current			
Cash		**—**	34.3
Accounts receivable	**15**	**334.6**	299.1
Inventory		**43.3**	64.2
Prepaid expenses and deposits		**28.1**	10.0
Cross-currency swap asset	**6**	**—**	4.3
Risk management asset	**15**	**41.3**	9.5
Total current assets		**447.3**	421.4
Property, plant and equipment	**5**	**10,030.1**	8,724.2
Other assets		**19.5**	18.9
Total assets		**10,496.9**	9,164.5
Liabilities			
Current			
Accounts payable and accrued liabilities		**783.8**	652.9
Debt	**6**	**—**	295.0
Deferred revenue		**37.5**	50.0
Cross-currency swap liability	**6, 15**	**39.6**	—
Lease and other obligations	**7**	**43.8**	32.4
Decommissioning provision	**8**	**36.6**	35.1
Risk management liability	**15**	**125.4**	108.6
Total current liabilities		**1,066.7**	1,174.0
Long-term debt	**6**	**2,665.0**	2,749.1
Lease and other obligations	**7**	**362.4**	224.1
Decommissioning provision	**8**	**314.7**	256.4
Deferred tax liability	**14**	**741.4**	445.2
Risk management liability	**15**	**19.6**	113.5
Total liabilities		**5,169.8**	4,962.3
Equity			
Share capital	**9**	**3,590.5**	3,052.8
Contributed surplus		**49.9**	49.9
Retained earnings		**1,686.7**	1,099.5
Total equity		**5,327.1**	4,202.2
Total liabilities and equity		**10,496.9**	9,164.5

Commitments and contingencies (Note 16)
Subsequent event (Note 20)
See accompanying notes to the consolidated financial statements.

/s/ Cody Church
Cody Church, Director

/s/ Navjeet (Bob) Singh Dhillon
Navjeet (Bob) Singh Dhillon, Director

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
Cdn$ millions, except per share amounts

For the Year Ended December 31,	Note	2023	2022
Revenues and other income			
Oil and natural gas sales	10	4,748.3	4,343.4
Sale of purchased products		46.3	64.7
Royalties		(556.9)	(666.8)
Oil and natural gas revenues		4,237.7	3,741.3
Gain (loss) on risk management contracts	15	69.6	(188.2)
Other income		1.0	5.3
		4,308.3	3,558.4
Expenses			
Purchased product		46.5	64.3
Blending costs		1,058.3	1,037.9
Production and operating		796.3	640.2
Transportation and processing		482.9	258.2
Acquired inventory	4	—	54.2
General and administrative		91.9	68.8
Interest	6	206.2	109.4
Transaction related costs	4	3.8	11.2
Finance costs	11	75.3	29.8
Depletion, depreciation and amortization	5	732.9	395.7
Foreign exchange (gain) loss	12	(22.1)	43.7
Unrealized (gain) loss on Sable remediation fund		(0.2)	0.7
		3,471.8	2,714.1
Share of equity investment income	4	—	11.3
Gain on step acquisition of equity method investee	4	—	132.1
Loss on termination of lease liability	7	—	(1.4)
Income before income taxes		836.5	986.3
Income tax expense (recovery)	14	249.3	(371.9)
Income and comprehensive income		587.2	1,358.2
Net income per share			
Basic and Diluted	13	2.94	0.63

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
Cdn$ millions

	Note	Share Capital	Contributed Surplus	Retained Earnings	Total Equity
Balance, December 31, 2021		2,513.7	49.9	(258.7)	2,304.9
Equity issuance - Caltex Acquisition	**4, 9**	295.8	—	—	295.8
Equity issuance - Stickney Acquisition	**4, 9**	242.0	—	—	242.0
Equity issuance - employees		1.7	—	—	1.7
Equity purchase - employees		(0.4)	—	—	(0.4)
Income and comprehensive income		—	—	1,358.2	1,358.2
Balance, December 31, 2022		**3,052.8**	**49.9**	**1,099.5**	**4,202.2**
Equity issuance - employees	**9**	0.7	—	—	**0.7**
Equity issuance – Pipestone Acquisition	**4, 9**	537.0	—	—	**537.0**
Income and comprehensive income		—	—	587.2	**587.2**
Balance, December 31, 2023		**3,590.5**	**49.9**	**1,686.7**	**5,327.1**

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
Cdn$ millions

For the Year Ended December 31,	Note	2023	2022
Cash flow from (used in) operating activities			
Net income		**587.2**	1,358.2
Items not involving cash	**18**	**971.1**	(135.5)
Decommissioning costs	**8**	**(37.9)**	(23.2)
Changes in non-cash working capital	**18**	**4.3**	255.8
		1,524.7	1,455.3
Cash flow from (used in) financing activities			
Draw of debt	**6, 12**	**375.3**	2,094.5
Repayment of debt	**6, 12**	**(700.0)**	—
Repayment of acquired debt	**4**	**(179.2)**	(530.2)
Proceeds from asset backed financing	**7**	**—**	137.0
Lease and other obligations	**7**	**(52.3)**	(27.7)
Loan to Stickney	**4**	**—**	(25.0)
Debt issuance costs		**(4.7)**	(27.5)
Issuance of common shares, net of share purchases	**9**	**0.7**	1.3
Changes in non-cash working capital	**18**	**0.6**	—
		(559.6)	1,622.4
Cash flow from (used in) investing activities			
Property, plant and equipment expenditures	**5**	**(1,026.8)**	(620.9)
Property acquisitions and dispositions, net	**5**	**—**	0.9
Expenditures on corporate combinations, net of cash acquired	**4**	**—**	(2,300.0)
Capitalized transaction costs	**4**	**(23.4)**	—
Investment in associates	**4**	**—**	(156.3)
Change in other assets		**—**	2.0
Changes in non-cash working capital	**18**	**50.8**	30.9
		(999.4)	(3,043.4)
Change in cash		**(34.3)**	34.3
Cash, beginning of period		**34.3**	—
Cash, end of period		**—**	34.3
Cash interest paid		**214.6**	99.4

See accompanying notes to the consolidated financial statements.

1. DESCRIPTION OF BUSINESS

Strathcona Resources Ltd. ("**Strathcona**" or the "**Company**") is a corporation resulting from the amalgamation of Strathcona Resources Ltd. and Pipestone Energy Corp. ("**Pipestone**") on October 3, 2023, pursuant to a plan of arrangement under the Business Corporations Act (Alberta) (the "**ABCA**"), (the "**Arrangement**"), details of which are included in Note 4. Upon completion of the Arrangement, Strathcona's Common Shares were listed on the TSX under the trading symbol "SCR" and commenced trading on October 5, 2023. Strathcona exists under, and is governed by, the provisions of the ABCA. These financial statements reflect the historical financial information of Strathcona Resources Ltd., commencing on October 3, 2023 also reflects the results of Pipestone.

At December 31, 2023, approximately 90.8% of the Company's shares were owned by certain limited partnerships comprising of Waterous Energy Fund and its affiliates (collectively, "**WEF**").

Strathcona is engaged in the exploration, acquisition, development and production of petroleum and natural gas reserves in western Canada. The consolidated financial statements (the "**financial statements**") include the results of Strathcona Resources Ltd. and its wholly owned subsidiaries.

The Company's head office is located at Suite 1900, 421 – 7 Avenue SW, Calgary, Alberta, Canada, T2P 4K9.

2. BASIS OF PREPARATION

Preparation

These financial statements have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board ("**IASB**"). These financial statements were authorized for issue by the Board of Directors on March 26, 2024.

These financial statements have been prepared on the historical cost basis except for those items that are presented at fair value as detailed in the accounting policies disclosed in Note 3.

In these financial statements, all amounts are expressed in Canadian dollars ("**CAD**" or "**C$**") unless otherwise indicated, which is the Company's functional and presentation currency.

Use of estimates and judgments

The preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from those estimated.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Information about certain areas of estimation uncertainty and critical judgments in applying accounting policies that affect amounts recognized in these financial statements is as follows:

Business combinations

Management is required to exercise judgment in determining whether assets acquired and liabilities assumed constitute a business. A business consists of an integrated set of assets and activities, comprised of inputs and processes, that is capable of being conducted and managed as a business by a market participant.

Business combinations are accounted for using the acquisition method of accounting, whereby the net identifiable assets acquired are recorded at fair value. The fair value of individual assets is often required to be estimated, which may involve estimating the fair values of proved plus probable reserves, tangible assets, undeveloped land, intangible assets and other assets. These estimates incorporate assumptions using indicators of fair value, as determined by management. Changes in any of the estimates or assumptions used in determining the fair value of the net identifiable assets acquired may impact the carrying values assigned to assets acquired and liabilities assumed and could have a material impact on earnings.

*Identification of cash-generating units (“**CGUs**”)*

For the purpose of impairment testing, assets that cannot be tested individually are grouped together into CGUs, which are the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. Determination of what constitutes a CGU is subject to management’s judgment. Factors considered in the classification include the integration between assets, shared infrastructure, the existence of common sales points, geography, geological structure and the manner in which management monitors and makes decisions about its operations. As such, the determination of a CGU may have an impact on the carrying value of the Company's assets in future periods and current periods.

Oil and natural gas reserves

Proved and probable reserves have been estimated by external experts and are based on a number of underlying assumptions including oil and natural gas prices, future costs, oil and natural gas in place and reservoir performance, all of which are inherently uncertain. Established industry techniques are used to generate these estimates, however, the reserves that are ultimately recovered cannot be known with certainty until the end of the field’s life. Changes in reserves estimates could have a material impact on unit-of-production rates used for depletion, timing of decommissioning obligations and impairment of oil and natural gas properties. The Company’s reserves are evaluated annually and reported to the Company by its independent qualified reserves evaluators.

*Recoverability of property, plant and equipment (“**PPE**”)*

The Company has significant investments in property, plant and equipment. Changes in circumstances or expectations of future performance of an individual asset may be an indicator that the asset is impaired requiring the carrying value to be written down to its recoverable amount. Evaluating whether an asset is impaired requires a high degree of judgment in estimating relevant future cash flows, based on assumptions about the future market prices, production output and discount rates.

*Exploration and evaluation (“**E&E**”) assets*

The accounting for E&E assets requires management to make judgments as to whether E&E investments have discovered a sufficient amount of economically recoverable reserves, which requires the quantity and realizable value of such reserves to be estimated and could be impacted by a shift in demand as global energy markets transition to a lower carbon-based economy. Previous estimates are sometimes revised as new information becomes available.

E&E assets remain capitalized as long as sufficient progress is being made in assessing whether the recovery of the reserves is technically feasible and commercially viable. The concept of “sufficient progress” is a judgmental area, and it is possible to have E&E assets remain classified as such for several years while additional E&E activities are carried out or the Company seeks government, regulatory, or internal approval for development plans. E&E assets are subject to ongoing management review to confirm the continued intent to establish the technical feasibility and commercial viability of the discovery. When management is making this assessment, changes to project economics, expected capital investments and production costs, results of other operators in the region, and access to infrastructure and potential infrastructure expansions are important factors considered.

Decommissioning provision

The Company has obligations in respect of decommissioning its oil and natural gas properties. The present value of the obligation is calculated based on estimated future cash flows, timing of remediation activities, estimated inflation rate and the credit adjusted discount rate applied. Assumptions, based on current economic factors, have been made to estimate the future liability. However, the actual cost of decommissioning 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.

Leases

Management applies judgment in reviewing each of its contractual arrangements to determine whether the arrangement contains a lease within the scope of IFRS 16 - Leases (“**IFRS 16**”). Leases that are recognized are subject to further management judgment and estimation in various areas specific to the arrangement. The estimates and assumptions related to the application of IFRS 16 include:

- Incremental borrowing rate: The incremental borrowing rates are based on judgments including economic environment, term, currency and the underlying risk inherent to the asset. The carrying balance of the right-of-use

(“**ROU**”) assets, lease obligations and the resulting accretion and depreciation expense, may differ due to changes in the market conditions and lease term.

- Lease term: Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions.

Financial Instruments

The estimated fair value of financial instruments is reliant upon a number of estimated variables including forward curves for commodity prices and foreign exchange rates. A change in these factors could result in a change to the overall estimated valuation of the instrument.

Income taxes

The calculation of deferred income tax assets and liabilities is based on management’s interpretation of applicable laws, regulations, relevant court decisions and estimates regarding the timing of reversals of temporary differences.

3. MATERIAL ACCOUNTING POLICY INFORMATION

Basis of consolidation

The financial statements include accounts of the Company and its subsidiaries. Subsidiaries are entities controlled by the Company. Subsidiaries are consolidated from the date that control commences until the date that control ceases. The accounting policies of subsidiaries align with the policies adopted by the Company. Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the financial statements.

Foreign currency

Transactions in foreign currencies are translated to Canadian dollars at exchange rates on the respective dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Non-monetary assets that are measured in a foreign currency at historical cost are translated using the exchange rate at the date of the transaction. Foreign currency differences arising on translation are recognized in earnings and are reported on a net basis.

Inventory

Inventory consists of raw crude oil, diluent and blended crude oil at the Company’s facilities, and in-transit via pipeline and rail. Inventory is carried at the lower of cost and net realizable value. Cost is determined by the first-in first-out method and includes direct purchase costs and costs of production (royalties, production and operating costs, transportation and processing costs, blending costs and depletion of oil and natural gas properties). Net realizable value is the estimated selling price in the ordinary course of business, less applicable selling expenses.

Property, plant and equipment

(i) General

Oil and natural gas properties and corporate assets, collectively, “property, plant and equipment”, are measured at cost less accumulated depletion, depreciation and amortization and accumulated impairment losses.

(ii) Oil and natural gas properties

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation and the initial estimate of a decommissioning obligation.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts are recognized as oil and natural gas properties only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in earnings as incurred. Such capitalized expenditures generally represent costs incurred in developing proved and/or probable reserves and bringing on or enhancing production from such reserves. The carrying amount of any significant replaced or sold component is derecognized. The costs of the day-to-day servicing of oil and natural gas properties are recognized in earnings as incurred.

When significant parts of an item of oil and natural gas properties have different useful lives, they are accounted for as separate items.

Gains and losses on disposal of an item of oil and natural gas properties are determined by comparing the proceeds from disposal with the carrying amount of oil and natural gas properties and are recognized in earnings.

(iii) Corporate assets

Costs associated with intangible assets, office furniture, fixtures, leasehold improvements, information technology and other corporate assets are carried at cost and depreciated based on the estimated useful lives of the assets.

Corporate assets also includes the recognition of ROU assets, in accordance with IFRS 16. ROU assets are depreciated on a straight-line basis over the shorter of the asset's useful life and the lease term. Depreciation on ROU assets is recognized in depletion, depreciation and amortization.

(iv) Non-monetary exchanges

Non-monetary exchanges of oil and natural gas properties are measured at fair value, unless the transaction lacks commercial substance or the fair value of the asset received or 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.

(v) Depletion and depreciation

Oil and natural gas properties, including related facilities, are depleted using the unit-of-production method by reference to the ratio of production in the period to the related proved and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of natural gas equates to one barrel of oil. These estimates are prepared by independent reserve engineers at least annually. Oil and natural gas properties are grouped with assets that are dedicated to serving the same reserves.

The estimated useful lives of depreciable assets are as follows:

Furniture and office equipment	30% declining balance
Computer hardware and systems software	30% declining balance
Vehicles	30% declining balance
Facilities	Straight-line over 15 - 20 years
Computer application software	Straight-line over 1 year
Leasehold improvements	Straight-line over the term of the lease

Exploration for and evaluation of mineral resources

E&E costs incurred prior to obtaining the legal right to explore are expensed. Costs incurred after the legal right to explore an area has been obtained are capitalized as exploration and evaluation assets. These costs can include license acquisition, geological and geophysical, drilling, sampling and other directly attributable internal costs. Exploration and evaluation assets are not depreciated and are accumulated in cost centers until technical feasibility and commercial viability of the project, area or field is determined or the assets are determined to be impaired. Technical feasibility and commercial viability of E&E assets is dependent upon the assignment of a sufficient amount of economically recoverable crude oil, condensate, natural gas, and natural gas liquids reserves and available infrastructure to support commercial development, as well as obtaining the appropriate internal and external approvals.

Once technical feasibility and commercial viability has been established for a project, area or field, the exploration and evaluation assets attributable to those reserves are first assessed for impairment by comparing the carrying amount to the greater of the assets' fair value less costs of disposal or value in use and are then transferred from exploration and evaluation assets to oil and natural gas properties. If a decision is made by the Company not to continue an E&E project, the E&E is derecognized and all associated costs are charged to the statement of comprehensive income in E&E expense at that time.

Impairment of non-financial assets

CGUs are reviewed at each reporting date to determine whether there is any indication that the carrying amount may exceed its recoverable amount. If any such indication exists, an impairment test is performed by comparing the CGU's carrying value to its estimated recoverable amount. The recoverable amount of a CGU is the greater of its value in use and its fair value less costs of disposal. An impairment loss is recognized if the carrying amount of a CGU exceeds its estimated recoverable amount.

Impairment losses are recognized in earnings. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the assets in the CGU on a pro rata basis.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss may be reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment loss had been recognized.

Business combinations

The acquisition method of accounting is used to account for business combinations. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of the exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date, irrespective of the extent of any minority interest. The excess of the cost of acquisition over the fair value of the Company's share of the net fair value of the identifiable assets, liabilities and contingent liabilities is recorded as goodwill. If the cost of an acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in earnings.

Transaction costs that are incurred in connection with a business combination, other than those associated with the issuance of debt or equity securities, are recognized in earnings.

There is an option to apply a concentration test that permits a simplified assessment of whether an acquired set of activities and assets is in fact a business. The optional concentration test is met if substantially all of the fair value of the assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets. An entity may make such an election separately for each transaction or other event. If the concentration test is met, the set of activities and assets is determined not to be a business and no further assessment is needed.

Leases

On the date that a leased asset becomes available for use, the Company recognizes an ROU asset and a corresponding lease obligation. Accretion expense associated with the lease obligation is charged to earnings over the lease period with a corresponding increase to the lease obligation. The lease obligation is reduced as payments are made against the principal portion of the lease. The ROU asset is depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis. Depreciation of the ROU asset is recognized in depletion, depreciation and amortization.

A lease obligation is measured at the commencement date of the lease term at the present value of the lease payments that have not yet been paid as of that date. The ROU asset is measured at cost, which is comprised of the amount of the initial measurement of the lease obligation, less any incentives received net of any onerous contracts, plus any lease payments made at, or before, the commencement date and initial direct costs and asset restoration costs, if any.

The rate implicit in the lease is used to determine the present value of the liability and ROU asset arising from a lease, unless this rate is not readily determinable, in which case the Company's incremental borrowing rate is used. Generally, the Company uses its incremental borrowing rate as the discount rate.

The lease obligation is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, extension or termination option. A corresponding adjustment is made to the carrying amount of the ROU asset, or is recorded in the earnings if the carrying amounts of the ROU asset has been reduced to $nil.

Provisions

(i) General

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The discount rate is adjusted for the Company's credit risk. Provisions are not recognized for future operating losses. The unwinding of the discount is recognized as a finance cost.

(ii) Decommissioning provision

The Company’s activities give rise to dismantling, decommissioning and site disturbance remediation activities. A provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning provisions are measured at their present value at the statement of financial position date, based on management’s best estimate of the expenditures required to settle the obligation at the end of the asset’s useful life. On a periodic basis, management reviews these estimates and changes are applied prospectively. Subsequent to the initial measurement, the provision is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs (accretion expense) whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning provisions are charged against the provision.

Financial instruments

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired, or when the Company has transferred substantially all risks and rewards of ownership.

Financial assets and liabilities are offset and the net amount is reported on the consolidated statement of financial position when there is a legally enforceable right to offset the recognized amounts, and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

i) Cash and Accounts Receivable

Cash comprise cash on hand. Accounts receivable, which are non-derivative financial assets that have fixed or determinable payment terms and are not quoted in an active market, are classified as financial assets at amortized cost and are reported at amortized cost. They are included in current assets.

*ii) Financial Derivative Instrument*s

Risk management contracts and cross-currency swaps are financial derivative instruments and are included in current assets and liabilities, except for those with maturities greater than 12 months after the end of the reporting period, which are classified as non-current assets and liabilities. The Company has not designated any of its financial derivative contracts as hedging instruments. The Company's financial derivative instruments are classified as financial assets or liabilities at fair value through profit or loss and are reported at fair value with changes in fair value recorded in net income or loss.

iii) Accounts Payable and Accrued Liabilities and Long-term Debt

These financial instruments are obligations to pay for goods or services that have been acquired in the ordinary course of business from suppliers or repay borrowings from lenders. They are classified as current liabilities if payment is due within one year or less. These financial instruments are classified as financial liabilities at amortized cost and are reported at amortized cost.

iv) 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, the Company 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 loss and are discounted at the effective interest rate of the related financial asset.

Fair value measurements

All financial and non-financial assets and liabilities for which fair value is measured or disclosed in these financial statements are further categorized using a three-level hierarchy based upon the inputs used to measure fair value:

- Level 1: Values are based on unadjusted quoted market prices in active markets for identical assets or liabilities.
- Level 2: Values are based on inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices).
- Level 3: Values are based on unobservable inputs.

The fair value hierarchy gives the highest priority to Level 1 inputs and the lowest priority to Level 3 inputs. At each reporting date, the Company determines whether transfers have occurred between levels in the hierarchy by reassessing the level of classification for each asset or liability measured or disclosed at fair value.

Fair values in these financial statements have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

- The value in use or fair value less costs of disposal is calculated to determine the recoverable amount of non-financial assets that are tested for impairment.

- The fair value of risk management contracts, foreign exchange swaps, or cross-currency swaps are based on listed market prices, if available. If a listed market price is not available, then fair value is estimated by discounting the difference between the contractual price and the current forward price for the residual maturity of the contract using a risk-free interest rate.

- The fair value of long-term debt is based upon observable market data and/or other sources utilizing assumptions that market participants would use to determine fair value.

Revenue

Revenues from the sale of crude oil and natural gas are measured based on the consideration specified in contracts with customers. The Company recognizes revenue when it transfers control of the product to the buyer and collection is reasonably assured. This is generally considered to occur when legal title to the product passes to customers, which is when it is physically transferred to the pipeline or other transportation method agreed upon. Purchases and sales of products that are entered into in contemplation of each other with the same counter party are recorded on a net basis. Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

The Company satisfies its performance obligations in contracts with customers upon the delivery of crude oil and natural gas, which is generally at a point in time. Performance obligations for services are satisfied over time as the service is provided. The Company sells its production of crude oil and natural gas pursuant to variable price contracts which generally have a term of one year or less. The transaction price for variable price contracts is based on the commodity index price, adjusted for quality, location and other factors depending on the contract terms. The amount of revenue recognized is based on the agreed transaction price with any variability in transaction price recognized in the same period.

The Company's revenue transactions do not contain significant financing components and payments are typically collected on the 25th day of the month following the prior month's production, with revenue being recorded once the product is delivered to a contractually agreed upon delivery point. 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 unfulfilled performance obligations.

Deferred revenue

For certain oil sales transported by rail, Strathcona receives consideration before the performance obligation is satisfied. The Company reports this as deferred revenue. The Company recognizes revenue when it transfers control of the product to the buyer and collection is reasonably assured.

Blending and transportation and processing expenses

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

Income tax

Income tax expense includes current and deferred tax. Income tax expense is recognized in earnings except to the extent that it relates to a business combination, items recognized directly in equity or other comprehensive income.

Current tax is the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date and any adjustment in respect of previous years.

Deferred tax is recorded for the effect of any temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit or loss. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized for unused tax losses, tax credits and deductible temporary differences, to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

Net income per share

Basic net income per share is calculated by dividing the net income attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted net income per share is determined by adjusting the net income attributable to common shareholders and the weighted average number of common shares outstanding for the effects of all potential common shares.

Segment reporting

An operating segment is a component of the Company that engages in business activities from which it may earn revenues and incur expenses. Segment results include items directly attributable to a segment as well as those that can be allocated on a reasonable basis. All inter-segment transactions are eliminated on consolidation.

The reportable segments of the Company have been derived because: (a) they engage in business activities from which revenues are earned and expenses are incurred; (b) their operating results are regularly reviewed by the Company’s chief operating decision maker, identified as the Company’s President and Chief Executive Officer, to make decisions about resources to be allocated to each segment and assess its performance; and (c) discrete financial information is available. The Company evaluates the financial performance and allocates resources to its operating segments primarily based on operating income. Operating income is defined as oil and natural gas sales less royalties, production and operating expenses, blending costs, transportation and processing expenses, and acquired inventory.

Changes in accounting policies

There were no changes that had a material effect on the reported net income or net assets of the Company during the periods presented in these audited consolidated financial statements.

4. ACQUISITIONS

<u>2023</u>

Acquisition of Pipestone Energy Corp.

On October 3, 2023, Strathcona completed the acquisition of Pipestone, at which time Pipestone and Strathcona were amalgamated and formed Strathcona Resources Ltd. The acquisition was structured through the Arrangement, where existing Pipestone shareholders received 0.067967 common shares of Strathcona Resources Ltd. for each Pipestone common share (19,010,920 Strathcona Resources Ltd. common shares), and Strathcona shareholders received 0.089278 common shares of Strathcona Resources Ltd. for each Strathcona Class A or Class B common share (195,224,688 Strathcona Resources Ltd. common shares).

The consideration for the acquisition was valued using the acquisition date fair value of Pipestone's equity interest as it was based on a quoted and reliable market price. The value of the consideration was $537.0 million.

The Company opted to apply the optional IFRS 3 concentration test, which resulted in the Pipestone acquisition being accounted as an asset acquisition.

The results of operations of Pipestone are included in these financial statements from the date of closing of the acquisition on October 3, 2023.

Assets Acquired and Liabilities Assumed

The following table summarizes the total consideration paid and net assets acquired:

Consideration	
Fair value of common shares issued	537.0
Capitalized transaction costs	23.4
Total consideration	560.4
Accounts receivable	54.1
Prepaid expenses and deposits	8.9
Risk management asset	1.1
Oil and natural gas properties	772.1
Right of use asset	106.2
Accounts payable and accrued liabilities	(89.3)
Risk management liability	(4.2)
Debt	(179.2)
Lease liability	(106.2)
Decommissioning provision	(3.1)
Net assets acquired	560.4

2022

Acquisition of Caltex Resources Ltd.

On November 30, 2021, an affiliate of WEF (“**WEF Fund II**”) and Strathcona completed the acquisition of Caltex Resources Ltd. (“**Caltex**”). Caltex was a private company engaged in the exploration, acquisition, development, and production of petroleum and natural gas reserves. Immediately after closing, Strathcona held a 50.0% economic interest (44.4% voting interest) in Caltex. WEF Fund II held the remaining interests. The acquired assets are located in Alberta and Western Saskatchewan, close to Strathcona’s Lloydminster Heavy Oil properties. Management determined it did not control Caltex at November 30, 2021, and accounted for its investment in Caltex using the equity method. At December 31, 2021, Strathcona's investment in Caltex was $221.9 million on the consolidated statement of financial position.

On January 31, 2022, Strathcona exchanged $30.9 million of its shares in Stickney Resources Ltd. (“**Stickney**”) (see following pages) with WEF Fund II for shares of Caltex (the “**Share Exchange**”). Following the Share Exchange, Strathcona held a 57.0% economic interest (44.4% voting interest) in both Stickney and Caltex. The remaining interests were held by WEF Fund II.

Subsequent to the Share Exchange on January 31, 2022, management determined that it did not control Caltex until Strathcona acquired the remaining 43.0% economic interest (55.6% voting interest) on March 11, 2022, as the Company did not have the ability to direct the relevant activities of Caltex, including the significant investing, financing, or otherwise strategic decisions. Accordingly, between January 31, 2022 and March 11, 2022, the Company continued to account for its investment in Caltex using the equity method. For the period from January 1, 2022 to March 11, 2022, Strathcona recognized $6.9 million as its share of profits from the investment in Caltex. This amount is included in the share of equity investment income on the Consolidated Statements of Comprehensive Income.

On March 11, 2022, Strathcona acquired the remaining 43.0% interest in Caltex from WEF Fund II in exchange for 132.6 million Class A shares (the “**Caltex Acquisition**”). This transaction was accounted for as a business combination through a step acquisition in accordance with IFRS 3 - Business Combinations (“**IFRS 3**”). Accordingly, the Company remeasured its interest in Caltex immediately before the acquisition date to its estimated fair value of $392.1 million, resulting in a gain of $132.1 million. This gain is included in the gain on step acquisition of equity method investee on the Consolidated Statements of Comprehensive Income. Immediately following the acquisition, Strathcona and Caltex were amalgamated.

The results of operations of Caltex are included in these financial statements from the date of closing of the acquisition on March 11, 2022.

Purchase Price Allocation

The following table summarizes the total consideration paid and net assets acquired:

Consideration	
Fair value of Strathcona's common shares issued	295.8
Fair value of pre-existing equity investment	392.1
Total consideration	687.9
Accounts receivable	35.5
Inventory	2.2
Prepaid expenses and deposits	0.9
Risk management asset	1.6
Oil and natural gas properties	1,097.0
Accounts payable and accrued liabilities	(16.6)
Risk management liability	(4.6)
Debt	(186.7)
Decommissioning provision	(18.3)
Deferred tax liability	(223.1)
Net assets acquired	687.9

If the closing of the Caltex Acquisition had occurred on January 1, 2022, the Company's oil and natural gas sales and income before income taxes for the twelve months ended December 31, 2022 would have been approximately $4,423.7 million and $947.4 million, respectively. During the twelve months ended December 31, 2022 actual revenue contributed by the Caltex assets was $356.0 million and net income before tax was $146.5 million.

Acquisition of Stickney Resources Ltd.

Stickney was formed by Strathcona and WEF Fund II for the purpose of acquiring the Tucker asset, a producing thermal oil property located in Cold Lake, Alberta. On January 31, 2022, Stickney acquired the Tucker asset for $800.0 million cash consideration before purchase price adjustments.

Upon close of the transaction, Strathcona paid $156.3 million cash. This was in addition to the $80.0 million deposit paid in 2021, for a total investment of $236.3 million. On January 31, 2022, Strathcona also issued an unsecured, interest-bearing loan of $25.0 million to Stickney. This loan was subsequently extinguished as part of the Stickney Acquisition (see below) on March 11, 2022. Strathcona held a 65.6% economic interest (44.4% voting interest) in Stickney immediately following the Tucker acquisition on January 31, 2022.

On January 31, 2022, immediately following the Tucker acquisition by Stickney, Strathcona completed the Share Exchange. Management determined that it did not control Stickney until Strathcona acquired the remaining economic and voting interest on March 11, 2022, as the Company did not have the ability to direct the relevant activities of Stickney, including the significant investing, financing, or otherwise strategic decisions. Accordingly, between January 31, 2022 and March 11, 2022, the Company accounted for its investment in Stickney using the equity method. The equity investment in Stickney was initially recorded at cost and the carrying amount was subsequently adjusted to recognize the Company's share of Stickney's profits and losses. For the period from January 31, 2022 to March 11, 2022, Strathcona recognized $4.4 million (December 31, 2021 - $nil) as its share of profits from the investment in Stickney.

On March 11, 2022, Strathcona acquired the remaining 43.0% interest (55.6% voting interest) in Stickney from WEF Fund II in exchange for 108.5 million Class A shares (the "**Stickney Acquisition**"). The Company opted to apply the optional IFRS 3 concentration test, which resulted in the transaction being accounted for as an asset acquisition. Immediately following the acquisition, Strathcona and Stickney were amalgamated.

The results of operations of Stickney are included in these financial statements from the date of closing of the acquisition on March 11, 2022.

Stickney Assets and Liabilities Acquired

The following table summarizes the total consideration paid and net assets acquired:

Consideration	
Fair value of Strathcona's common shares issued	242.0
Fair value of pre-existing equity investment	209.8
Total consideration	451.8
Cash	0.2
Accounts receivable	45.1
Inventory	3.6
Prepaid expenses and deposits	0.4
Oil and natural gas properties	804.6
Accounts payable and accrued liabilities	(15.2)
Risk management liability	(8.3)
Debt	(293.1)
Loan from Strathcona (Note 17)	(25.0)
Decommissioning provision	(60.5)
Net assets acquired	451.8

Acquisition of Serafina Energy Ltd.

On August 29, 2022, Strathcona acquired all of the issued and outstanding shares of Serafina Energy Ltd. ("**Serafina**") for cash consideration of $1.9 billion and $400.0 million in acquisition notes (Note 6). Serafina was a private company engaged in the exploration, acquisition, development, and production of petroleum and natural gas reserves, with thermal heavy oil assets located in Saskatchewan.

This transaction was accounted for as a business combination in accordance with IFRS 3 using the acquisition method. The results of operations of Serafina are included in these financial statements from the date of closing of the acquisition on August 29, 2022.

The results of operations of Serafina are included in these financial statements from the date of closing of the acquisition on August 29, 2022.

Serafina Purchase Price Allocation

The following table summarizes the total consideration paid and net assets acquired:

Consideration	
Cash	1,900.0
Acquisition notes (Note 6)	400.0
Total consideration	2,300.0
Cash	0.4
Accounts receivable	41.3
Inventory	54.2
Prepaid expenses and deposits	3.3
Risk management asset	67.7
Oil and natural gas properties	3,019.7
Exploration and evaluation assets	117.3
Right of use assets	17.2
Accounts payable and accrued liabilities	(87.8)
Deferred revenue	(12.2)
Risk management liability	(240.1)
Debt	(50.4)
Leases	(17.6)
Decommissioning provision	(19.0)
Deferred tax liability	(594.0)
Net assets acquired	2,300.0

Inventory acquired in the acquisition of Serafina was expensed as Acquired inventory on the consolidated statement of comprehensive income when it was sold.

If the acquisition of Serafina had occurred on January 1, 2022, the Company's oil and natural gas sales and income before income taxes for the twelve months ended December 31, 2022 would have been approximately $5,274.9 million and $949.1 million, respectively. During the twelve months ended December 31, 2022, actual revenue contributed by the Serafina assets was $397.2 million and net income before tax was $107.0 million.

Transaction Related Costs

For the year ended December 31, 2023, Strathcona incurred $27.2 million (December 31, 2022 - $11.2 million) in transaction related costs of which $23.4 million was capitalized in connection with the asset acquisition of Pipestone (December 31, 2022 - $nil).

5. PROPERTY, PLANT AND EQUIPMENT

	Oil and natural gas properties	Exploration and evaluation assets	Corporate Assets	Right of Use Assets	Total
Cost					
Balance, January 1, 2021	4,203.4	—	35.3	104.7	4,343.4
Additions	618.6	—	2.3	5.5	626.4
Caltex Acquisition (Note 4)	1,097.0	—	—	—	1,097.0
Stickney Acquisition (Note 4)	804.6	—	—	—	804.6
Serafina Acquisition (Note 4)	3,019.7	117.3	—	17.2	3,154.2
Acquisitions and dispositions - other	(0.9)	—	—	—	(0.9)
Change in decommissioning provision (Note 8)	106.2	—	—	—	106.2
Balance, December 31, 2022	9,848.6	117.3	37.6	127.4	10,130.9
Additions	1,017.5	—	10.9	61.8	**1,090.2**
Pipestone Acquisition (Note 4)	772.1	—	—	106.2	**878.3**
Change in decommissioning provision (Note 8)	66.2	—	—	—	**66.2**
Balance, December 31, 2023	**11,704.4**	**117.3**	**48.5**	**295.4**	**12,165.6**
Accumulated DD&A and Impairment					
Balance, January 1, 2022	(954.2)	—	(26.5)	(18.0)	(998.7)
Depletion, depreciation and amortization	(396.8)	—	(2.7)	(8.5)	(408.0)
Balance, December 31, 2022	(1,351.0)	—	(29.2)	(26.5)	(1,406.7)
Depletion, depreciation and amortization	(694.5)	—	(5.7)	(28.6)	**(728.8)**
Balance, December 31, 2023	**(2,045.5)**	**—**	**(34.9)**	**(55.1)**	**(2,135.5)**
Net book value, December 31, 2022	8,497.6	117.3	8.4	100.9	8,724.2
Net book value, December 31, 2023	**9,658.9**	**117.3**	**13.6**	**240.3**	**10,030.1**

For the year ended December 31, 2023, $38.0 million of direct and incremental overhead charges were capitalized ($19.7 million for the year ended December 31, 2022).

The calculation of depletion for the year ended December 31, 2023 includes $13.0 billion of estimated future development costs required to bring the Company's estimated proved plus probable reserves to production (December 31, 2022 – $9.1 billion). Depletion includes an adjustment related to oil inventory of $4.1 million (December 31, 2022 – $12.3 million).

At December 31, 2023, the Company evaluated its CGUs for indicators of impairment and determined that no indicators were present.

6. DEBT

As at	December 31, 2023	December 31, 2022
Revolving Credit Facility - due Feb 27, 2026	**2,036.3**	1,706.7
Term Credit Facility - due Feb 29, 2024	**—**	701.6
Total Credit Facilities(1)	**2,036.3**	2,408.3
Senior Notes - due Aug 1, 2026	**662.2**	677.7
Unamortized debt issuance costs	**(33.5)**	(41.9)
Total debt	**2,665.0**	3,044.1
Current debt(2)	**—**	295.0
Long-term debt	**2,665.0**	2,749.1

(1) The Company periodically borrows from its Credit Facilities in US dollars ("**USD**" or "**US$**") and concurrently enters into cross-currency interest rate swap ("**CCS**") contracts to take advantage of an interest rate arbitrage that results from the relationship between CAD and USD interest rates and forward foreign exchange curves. Foreign currency risk associated with these borrowings are eliminated at the time of borrowing using CCS contracts (see Note 15). Debt on the balance sheet includes the CAD equivalent of USD borrowings, translated at the period end exchange rate, which does not include the offsetting impact of CCS contracts. The terms of the Revolving Credit Facility and the Term Credit Facility allow the CAD equivalent of USD borrowings to exceed contracted amounts due to fluctuations in foreign exchange, provided that settlement amounts have been fixed upfront using CCS contracts. At December 31, 2023, the CCS contracts had a liability value of $39.6 million (December 31, 2022 - $4.3 million asset) and total debt includes an unrealized gain of $41.3 million (December 31, 2022 - unrealized loss of $5.9 million) related to USD borrowings on Credit Facilities. Unrealized gains or losses on USD borrowings and offsetting unrealized gains or losses on CCS contracts are included in foreign exchange gains or losses on the Consolidated Statements of Income and Comprehensive Income (see Note 12).

(2) Current debt at December 31, 2022 related to the Term Credit Facility. The Term Credit Facility was paid in full and cancelled on December 28, 2023.

Bank Credit Facilities

(a) Covenant-Based Revolving Credit Facility

As at December 31, 2023, the Company had a covenant-based revolving credit facility of $2.3 billion (December 31, 2022 - $2.0 billion) with a syndicate of Canadian, U.S. and international financial institutions (the "**Revolving Credit Facility**"). The Revolving Credit Facility was increased from $2.0 billion to $2.3 billion on October 3, 2023, concurrent with the Pipestone Acquisition.

The Revolving Credit Facility has a maturity date of February 27, 2026. There are no mandatory payments on the Revolving Credit Facility. Borrowings under the Revolving Credit Facility may be drawn and repaid from time to time by the Company in Canadian or U.S. dollars. In addition, the covenant-based Revolving Credit Facility is not a borrowing base facility and does not require annual or semi-annual reviews.

The Revolving Credit Facility bears interest at the applicable prime lending rate, base rate, bankers' acceptance or Secured Overnight Financing Rate ("**SOFR**") plus applicable margins. The applicable margin charged by the lenders is dependent on the Company's Senior Debt to Adjusted EBITDA ratio (as defined below) for the most recently completed quarter. The Revolving Credit Facility is guaranteed by the Company's subsidiaries, and is secured by a security interest in substantially all of the existing and future assets of the Company and its subsidiaries, including by way of a floating charge debenture granted by the Company and each of its subsidiaries.

As at December 31, 2023, the Company had letters of credit outstanding under the Revolving Credit Facility of $10.6 million (December 31, 2022 - $12.5 million).

(b) Term Credit Facility

As at December 31, 2022, the Company had a $700.0 million term loan with a syndicate of Canadian financial institutions (the "**Term Credit Facility**" and together with the Revolving Credit Facility, the "**Credit Facilities**"). The Term Credit Facility had a maturity date of February 29, 2024. Borrowings under the Term Credit Facility were fully advanced in August 2022 and amortization payments were made throughout 2023; the remaining balance of the Term Credit Facility was repaid on December 28, 2023, and commitments thereunder were cancelled.

(c) Availability under bank credit facilities and liquidity

Availability under the Company's bank credit facilities and liquidity is calculated as follows:

As at	December 31, 2023	December 31, 2022
Credit capacity	**2,300.0**	2,700.0
Credit facilities debt at period end exchange rate	**(2,036.3)**	(2,408.3)
Unrealized (gain) loss on US borrowings	**(41.3)**	5.9
Letters of credit outstanding	**(10.6)**	(12.5)
Availability	**211.8**	285.1

(d) Financial Covenants

As at December 31, 2023, the Revolving Credit Facility had three financial covenants which are calculated quarterly (as set out below) in accordance with the credit agreement governing the Revolving Credit Facility (the "**Credit Agreement**").

(i) Total Debt to Adjusted EBITDA Ratio – All debt excluding the Financing Agreement (see Note 7), capital leases and letters of credit constituting debt ("**Total Debt**"), each as defined in the Credit Agreement shall not exceed 4.0 times trailing 12-month net income before non-cash items, income taxes, interest expense and extraordinary and non-recurring losses, adjusted for material acquisitions or dispositions as if they occurred on the first day of the calculation period ("**Adjusted EBITDA**"). For the purposes of Adjusted EBITDA, lease payments are deducted from the calculation if a lease would have been considered an operating lease before the adoption of IFRS 16. Total Debt may include the value of the Company's undiscounted inactive abandonment and reclamation obligations for a material jurisdiction if the liability management ratio in that jurisdiction falls below the minimum maintenance level required under the Credit Agreement (1.0 in British Columbia and 2.0 in all other material jurisdictions). Liability management ratios are calculated by provincial regulators based on deemed asset and deemed liability values determined by the respective regulator, other than for British Columbia, which is calculated by the Company based on past practice of the BC Oil and Gas Commission.

(ii) Senior Debt to Adjusted EBITDA Ratio – Total Debt excluding permitted junior debt (e.g. Senior Notes), as defined in the Credit Agreement, shall not exceed 3.5 times trailing 12-month Adjusted EBITDA.

(iii) Interest Coverage Ratio – Trailing 12-month Adjusted EBITDA, shall not be less than 3.5 times cash interest expense, as defined in the Credit Agreement.

As at December 31, 2023, the Company was in compliance with such financial covenants, which are summarized in the following table:

As at	December 31, 2023
Total Debt to Adjusted EBITDA Ratio (≤ 4.00)	**1.44**
Senior Debt to Adjusted EBITDA Ratio (≤ 3.50)	**1.09**
Interest Coverage Ratio (≥ 3.50)	**8.22**

Senior Notes

As at December 31, 2023, Strathcona had $662.2 million (December 31, 2022 - $677.7 million) of senior unsecured notes outstanding, in aggregate principal amount of US$500.0 million, due August 1, 2026 (the "**Senior Notes**"). The Senior Notes bear interest at 6.875% per annum, payable semi-annually in arrears on February 1 and August 1 of each year. The Senior Notes are redeemable at Strathcona's option, in whole or in part, at the following redemption prices:

Date	Price
August 1, 2023	**105.156 %**
August 1, 2024	**101.719 %**
August 1, 2025 and thereafter	**100.000 %**

The Senior Notes have no financial maintenance covenants.

Demand Letter of Credit Facility

As at December 31, 2023, the Company had a $100.0 million (December 31, 2022 - $60.0 million) demand letter of credit facility with a financial institution (the "**LC Facility**"). The LC Facility is supported by an account performance security guarantee issued by Export Development Canada in favour of the financial institution. The Company and its subsidiaries have indemnified Export Development Canada for the amount of any payment made by Export Development Canada to the financial institution pursuant to such account performance security guarantee; however, the obligations under such indemnity are unsecured. The letters of credit outstanding under the LC Facility do not impact the Company's borrowing capacity under the Revolving Credit Facility. As at December 31, 2023, the Company had letters of credit in the amount of $69.0 million (December 31, 2022 - $52.6 million) outstanding under the LC Facility.

Interest Expense

For the Year Ended December 31,	2023	2022
Credit Facilities interest	**178.4**	64.7
Senior Notes interest	**46.4**	44.7
Realized gain on interest rate swaps	**(18.6)**	—
Interest expense	**206.2**	109.4

7. LEASE AND OTHER OBLIGATIONS

As at	December 31, 2023	December 31, 2022
Lease obligations, beginning of year	**119.5**	112.7
Leases acquired through acquisitions	**106.2**	17.6
Additions	**61.8**	5.5
Accretion (Note 11)	**14.5**	11.4
Settlements	**(43.6)**	(27.7)
Foreign exchange	**0.4**	—
Lease obligations, end of year	**258.8**	119.5
Other obligations, beginning of year	**137.0**	—
Additions	**—**	137.0
Accretion (Note 11)	**19.1**	—
Settlements	**(8.7)**	—
Other obligations, end of year	**147.4**	137.0
Lease and other obligations, end of year	**406.2**	256.5
Lease and other obligations current portion	**43.8**	32.4
Lease and other obligations long-term portion	**362.4**	224.1

Other obligations include an asset-backed financing agreement on certain processing facilities interest (the "**Financing Agreement**"). The Financing Agreement has a maturity date of January 1, 2031 and bears interest at the applicable lending rate plus 7.00%. Interest payments are made on a monthly basis with principal payments that began on August 1, 2023. The Company has the option to reduce principal payments and make interest and principal payments in kind until August 1, 2024. The Company may also repurchase the processing facilities interest (the "**Repurchase Option**") at any time at the specified prices set out in the Financing Agreement. The Repurchase Option is a combination of the remaining principal balance and a varying option premium that is dependent on the time of exercise.

8. DECOMMISSIONING PROVISION

As at	December 31, 2023	December 31, 2022
Balance, beginning of year	**291.5**	106.1
Additions	**1.6**	1.8
Liabilities acquired through acquisitions (Note 4)	**3.1**	98.0
Liabilities disposed	**—**	(0.1)
Settlements – government grant[1]	**(0.3)**	(5.0)
Settlements – other	**(37.9)**	(23.2)
Changes in estimates	**64.6**	104.4
Accretion (Note 11)	**28.7**	9.5
Balance, end of year	**351.3**	291.5
Current portion	**36.6**	35.1
Long-term portion	**314.7**	256.4

(1) Relates to amounts granted to the Company through the Site Rehabilitation Program (Alberta), Dormant Sites Reclamation Program (British Columbia) and the Accelerated Site / Closure Program (Saskatchewan) to pay service companies to complete abandonment and reclamation work.

As at December 31, 2023, the uninflated and undiscounted estimated cash flows required to settle the obligation were $1,012.9 million (December 31, 2022 – $1,015.8 million), which have been inflated at a rate of 2.00% (December 31, 2022 – 2.00%) and discounted using a credit adjusted rate of 8.00% (December 31, 2022 – 9.60%). The expected timing of payment of the cash flows required for settling the obligations are substantially expected to be incurred between 2024 and 2082.

9. SHARE CAPITAL

At December 31, 2023, the authorized capital of the Company consists of an unlimited number of voting common shares and an unlimited number of preferred shares. Prior to the Pipestone Acquisition, the authorized capital of the Company consisted of an unlimited number of voting Class A and Class B common shares and an unlimited number of preferred shares. The Class A and Class B common shares were exchanged for common shares on October 3, 2023. No preferred shares have been issued by the Company as at December 31, 2023 (December 31, 2022 – $nil).

The following table provides a summary of the Company's issued and outstanding common shares:

	Common Shares		Class A Common Shares		Class B Common Shares		Total Common Shares	
	Shares	$	Shares	$	Shares	$	Shares	$
Balance, December 31, 2021	—	—	845.4	1,095.5	1,099.4	1,418.2	1,944.8	2,513.7
Issuance – Caltex Acquisition (Note 4)	—	—	132.6	295.8	—	—	132.6	295.8
Issuance – Stickney Acquisition (Note 4)	—	—	108.5	242.0	—	—	108.5	242.0
Issuance – employees	—	—	—	—	0.8	1.7	0.8	1.7
Purchase – employees	—	—	—	—	(0.2)	(0.4)	(0.2)	(0.4)
WEF II Holdco Amalgamation [1]	—	—	(153.9)	(343.3)	153.9	343.3	—	—
Balance, December 31, 2022	—	—	932.6	1,290.0	1,253.9	1,762.8	2,186.5	3,052.8
Issuance – employees	—	—	—	—	0.2	0.7	**0.2**	**0.7**
Issuance (conversion) – share exchange (Note 4) [2]	195.2	3,053.5	(932.6)	(1,290.0)	(1,254.1)	(1,763.5)	**(1,991.5)**	**—**
Equity issuance – Pipestone Acquisition (Note 4) [2]	19.0	537.0	—	—	—	—	**19.0**	**537.0**
Balance, December 31, 2023	**214.2**	**3,590.5**	**—**	**—**	**—**	**—**	**214.2**	**3,590.5**

(1) On December 30, 2022, Strathcona amalgamated with one of its shareholders, WEF II Holdco Corp. ("WEF II Holdco") pursuant to the ABCA. Immediately prior to the amalgamation, WEF II Holdco was wholly owned by one of WEF's limited partnerships, and had no

liabilities or assets other than its ownership of Strathcona shares. As part of the amalgamation, the 241.1 million Class A common shares held by WEF II Holdco were cancelled and 87.2 million Class A common shares and 153.9 million Class B common shares of Strathcona were reissued to one of WEF's limited partnerships.

(2) In connection with the Pipestone Acquisition, existing Strathcona shareholders received 0.089278 common shares of Strathcona Resources Ltd. for each Class A or Class B common share held, and existing Pipestone shareholders received 0.067967 common shares of Strathcona Resources Ltd. for each Pipestone common share held (Note 4).

10. OIL AND NATURAL GAS SALES

For the Year Ended December 31,	2023	2022
Bitumen blend	**2,280.8**	2,358.8
Heavy oil, blended and raw	**1,809.1**	1,326.5
Light oil and condensate	**431.0**	341.3
Other natural gas liquids	**79.4**	96.8
Natural gas	**148.0**	220.0
Oil and natural gas sales	**4,748.3**	4,343.4

11. FINANCE COSTS

For the Year Ended December 31,	2023	2022
Accretion of lease obligations (Note 7)	**14.5**	11.4
Accretion of other obligations (Note 7)	**19.1**	—
Accretion of decommissioning provision (Note 8)	**28.7**	9.5
Amortization of debt issuance costs	**13.0**	8.9
Finance costs	**75.3**	29.8

12. FOREIGN EXCHANGE (GAIN) LOSS

For the Year Ended December 31,	2023	2022
Realized (gain)	**(1.4)**	(5.7)
Unrealized (gain) loss – Senior Notes	**(15.6)**	45.9
Unrealized (gain) loss – Credit Facilities[1]	**(47.2)**	10.1
Unrealized loss (gain) – cross-currency swaps[1]	**43.9**	(8.1)
Unrealized (gain) loss – other	**(1.8)**	1.5
Foreign exchange (gain) loss	**(22.1)**	43.7

(1) Strathcona enters into CCS contracts, which eliminate foreign currency risk on USD denominated debt drawn under the Credit Facilities. At maturity, the realized gains and losses relating to USD borrowings will be offset by the realized gains and losses on CCS contracts. See Note 6.

13. NET INCOME PER SHARE

Basic and diluted per share amounts are calculated by taking net income divided by the weighted average number of common shares outstanding. At December 31, 2023 and 2022, the Company had no dilutive instruments outstanding. The weighted average common shares as at December 31, 2023 are adjusted for the exchange ratios pursuant to the Pipestone Acquisition (Note 4). At December 31, 2022, the weighted average common shares as are not adjusted for the Class A and Class B common share exchange ratios pursuant to the Pipestone Acquisition (Note 4).

For the Year Ended December 31,	2023	2022
Weighted average common shares (millions) – basic and diluted	**199.9**	2,140.8

14. INCOME TAXES

Estimated future income tax deductions

The Company has approximately $6,081.1 million of estimated future income tax deductions, in various taxpool categories, available at December 31, 2023 (December 31, 2022 - $6,038.1 million).

Total income tax expense (recovery)

	2023	2022
Current	**(46.9)**	—
Deferred		
Origination and reversal of temporary differences	**255.2**	209.7
Change in expected statutory tax rates	**(0.8)**	5.2
Adjustments for prior years	**41.8**	(3.0)
Change in unrecognized tax losses	**—**	(583.8)
	296.2	(371.9)
Total income tax expense (recovery)	**249.3**	(371.9)

During the year ended December 31, 2023, a current tax recovery of $46.9 million was recorded upon filing of the final tax return of Serafina Energy Ltd., which resulted from an income tax election to apply fair value treatment to financial derivative contracts. The current tax recovery was offset by a corresponding deferred tax expense due to the liability recorded by Strathcona to reflect the income inclusion related to the election filed.

Reconciliation of effective tax rate

	2023	2022
Net income before income tax	**836.5**	986.3
Expected tax rate	**24.3 %**	24.4 %
Expected income tax expense	**203.6**	240.7
Non-deductible expenses – equity investment income	**—**	(2.8)
Non-deductible expenses – gain on step acquisition of equity method investee	**—**	(32.2)
Non-deductible expenses – other	**0.3**	0.1
Change in unrecognized tax losses	**—**	(583.8)
Change in expected statutory tax rates	**(0.8)**	5.2
Adjustments for prior years	**41.8**	(3.0)
Other	**4.4**	3.9
Total income tax expense (recovery)	**249.3**	(371.9)

Recognized deferred income tax asset and liabilities

The movement in deferred income tax assets and liabilities is as follows:

	January 1, 2023	Recognized in earnings	December 31, 2023
Deferred income tax assets			
Financial derivative contracts	51.8	(26.5)	**25.3**
Decommissioning provision	71.1	14.4	**85.5**
Lease obligations	29.4	33.4	**62.8**
Non-capital losses	716.9	(186.2)	**530.7**
Financing costs	4.5	(0.8)	**3.7**
Other	59.6	(7.3)	**52.3**
	933.3	(173.0)	**760.3**
Deferred income tax liabilities			
Deferred partnership income	(61.3)	54.1	**(7.2)**
Property, plant and equipment	(1,317.2)	(177.3)	**(1,494.5)**
	(1,378.5)	(123.2)	**(1,501.7)**
Deferred tax liability	**(445.2)**	**(296.2)**	**(741.4)**

	January 1, 2022	Recognized on Caltex Acquisition	Recognized on Serafina Acquisition	Recognized in earnings	December 31, 2022
Deferred income tax assets					
Financial derivative contracts	29.0	0.7	41.7	(19.6)	**51.8**
Decommissioning provision	25.8	4.4	4.6	36.3	**71.1**
Lease obligations	27.8	—	4.3	(2.7)	**29.4**
Non-capital losses	310.6	4.3	—	402.0	**716.9**
Financing costs	2.8	1.0	0.4	0.3	**4.5**
Other	45.5	—	—	14.1	**59.6**
	441.5	10.4	51.0	430.4	**933.3**
Deferred income tax liabilities					
Deferred partnership income	(25.7)	(13.2)	—	(22.4)	**(61.3)**
Property, plant and equipment	(415.8)	(220.3)	(645.0)	(36.1)	**(1,317.2)**
	(441.5)	(233.5)	(645.0)	(58.5)	**(1,378.5)**
Deferred tax liability	**—**	**(223.1)**	**(594.0)**	**371.9**	**(445.2)**

Non-capital losses

Expiry Year	2030	2031	2032	2033	2034	Thereafter	Total
Non-capital loss balances	211.0	156.2	196.2	479.7	327.7	802.3	2,173.1

Unrecognized deferred income tax assets

A temporary difference has not been recognized in respect of the following items:

	2023	2022
Property, plant and equipment	**80.2**	80.2
Capital losses	**67.7**	67.7
	147.9	147.9

15. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

At December 31, 2023, the Company's financial instruments include accounts receivable, risk management contracts, the Sable remediation fund, accounts payable and accrued liabilities, cross-currency swaps, other obligations and debt.

The estimated fair values of the financial instruments have been determined based on the Company's assessment of available market information. These estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. The fair values of the financial instruments, other than the Company's risk management contracts, debt and Sable remediation fund approximate their carrying amounts due to the short-term maturity of these instruments.

The Company's risk management contracts and CCS contracts were classified as Level 1 in the fair value hierarchy. For purposes of estimating the fair value of these instruments, the Company used quoted market prices in active markets for identical assets or liabilities. The Sable remediation fund was classified as Level 2 in the fair value hierarchy. For the purposes of estimating the fair value of this instrument, the Company used estimates from third-party brokers and observable market data and/or other sources utilizing assumptions that market participants would use to determine fair value.

The Company's Senior Notes were classified as Level 1 in the fair value hierarchy. At December 31, 2023, the fair value of the Company's Senior Notes was $634.4 million. The fair value of all other debt approximates its carrying amount given the indexed rates of interest.

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities. These risks include credit risk, liquidity risk and market risk. There have been no significant changes in the Company's risk management policies or exposures during the year ended December 31, 2023.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. This will arise principally from outstanding receivables related to oil and natural gas customers, counterparties related to financial derivative contracts and joint interest partners.

On entering into any business contract, the extent to which the arrangement exposes the Company to credit risk is considered. The Company's policy to mitigate credit risk associated with these balances is to establish relationships with reputable counterparties, review the financial capacity of its counterparties, may request prepayment and, in certain circumstances, the Company may seek enhanced credit protection from a counterparty or purchase accounts receivable insurance. Receivables from oil and natural gas sales are generally collected on the 25th day of the month following production. Joint operations receivables are typically collected within one to three months of the invoice being issued.

The Company's maximum exposure to credit risk at December 31, 2023 is in respect of accounts receivable, net of expected credit losses provision and risk management asset. As at December 31, 2023, $2.1 million of accounts receivable were past due, all of which were considered collectable (December 31, 2022 – $3.0 million).

The following table provides a summary of the Company's maximum exposure to credit risk:

As at	December 31, 2023	December 31, 2022
Oil and natural gas sales	**298.3**	293.0
Joint interest partners	**7.1**	3.3
Other	**30.8**	4.6
	336.2	300.9
Allowance for credit losses	**(1.6)**	(1.8)
Accounts receivable	**334.6**	299.1
Cross-currency swap asset	**—**	4.3
Risk management asset	**41.3**	9.5
Total credit exposure	**375.9**	312.9

The oil and gas industry has a pre-arranged monthly clearing day for payment of revenues from all buyers of oil and natural gas; this occurs on or about the 25th day following the month of sale. As a result, the Company's production revenues are current. All other accounts receivable are generally contractually due within 30 days.

The Company had one external customer exceeding 10% of total oil and natural gas sales that accounted for approximately 16% or $738.0 million of the Company's revenue for the year ended December 31, 2023 (December 31, 2022 – no external customers exceeding 10% of total oil and natural gas sales). Included in accounts receivable at December 31, 2023 was $298.3 million of accrued sales revenue for December 2023 production (December 31, 2022 - $293.0 million for December 2022 production).

Credit risk related to joint interest receivables is mitigated by obtaining partner approval of significant capital expenditures prior to expenditure and in certain circumstances may require cash deposits in advance of incurring financial obligations on behalf of joint interest partners. The Company may have the ability to withhold production from joint interest partners in the event of non-payment or may be able to register security on the assets of joint interest partners.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company regularly prepares and updates budgets and forecasts in order to monitor its liquidity and ability to meet its financial obligations and commitments, including the ability to comply with financial covenants. As of the date of these financial statements, management's forecasts for Strathcona indicate that financial covenants for the next twelve months will be met under the Credit Facilities and that the Company has sufficient resources to manage the working capital deficit.

At December 31, 2023, the Company had availability under the Revolving Credit Facility of $211.8 million after considering letters of credit outstanding. At December 31, 2022, availability under the Revolving Credit Facility was $285.1 million, see Note 6.

Future liquidity depends on the ability of Strathcona to access debt markets, availability under credit facilities, availability of additional equity, cash flow from operations and the ability to comply with financial covenants. Various industry risk factors, including uncertainty around improvements in global commodity prices and pipeline and transportation capacity constraints in Western Canada, may adversely affect Strathcona's future liquidity.

At December 31, 2023, the Company had a working capital deficit of $415.3 million. The deficit primarily results from accounts payable and accrued liabilities exceeding accounts receivable. The Company actively manages its cash forecasts and working capital requirements.

The following tables detail the cash flows and contractual maturities of the Company's financial liabilities:

As at December 31, 2023	Total	<1 year	1-3 years	4-5 years	> 5 years
Revolving Credit Facility[1] (Note 6)	**2,077.6**	—	2,077.6	—	—
Senior Notes[2] (Note 6)	**798.7**	45.5	45.5	707.7	—
Accounts payable and accrued liabilities	**783.8**	783.8	—	—	—
Risk management contract liability	**145.0**	125.4	19.6	—	—
Lease and other obligations[3] (Note 7)	**610.2**	83.8	163.5	118.4	244.5
Total	**4,415.3**	1,038.5	2,306.2	826.1	244.5

(1) Contractual amount reflects contracted settlement price on CCS contracts and excludes future interest payments on borrowings.

(2) Amounts represent repayment of the Senior Notes ($662.2 million) and associated interest payments ($136.5 million) based on foreign exchange rate in effect on December 31, 2023.

(3) Amounts relate to undiscounted payments for lease and other obligations. The estimation of future cash payments related to other obligations are subject to forecast lending rates and timing of exercise of the Repurchase Option. The Repurchase Option on the Financing Arrangement is assumed to be exercised on January 1, 2029. See Note 7.

Market risk

Market risk is the risk that the future fair value or cash flows of a financial instrument will fluctuate due to changes in market prices. Market risk is composed of commodity price risk, foreign exchange risk and interest rate risk.

The fair value of the Company's risk management contracts (excluding cross-currency interest rate swaps) was as follows:

As at	December 31, 2023				December 31, 2022		
	Commodity	Foreign Exchange	Interest Rate	Total	Commodity	Foreign Exchange	Total
Risk management asset – current	**23.5**	**—**	**17.8**	**41.3**	9.5	—	9.5
Risk management liability – current	**(101.9)**	**(23.5)**	**—**	**(125.4)**	(108.6)	—	(108.6)
Risk management liability – long-term	**—**	**(4.6)**	**(15.0)**	**(19.6)**	(76.8)	(36.7)	(113.5)
Total (liability) asset	**(78.4)**	**(28.1)**	**2.8**	**(103.7)**	(175.9)	(36.7)	(212.6)

The Company's gain (loss) risk management contracts was as follows:

For the Year Ended December 31,	2023	2022
Realized loss	**(42.4)**	(278.6)
Unrealized gain	**112.0**	90.4
Total gain (loss) on risk management contracts	**69.6**	(188.2)

Commodity price risk

The Company's operational results and financial condition are largely dependent on the commodity price received for oil and natural gas production. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, weather, economic and geopolitical factors.

The following table summarize the Company's risk management as at December 31, 2023:

Term	Contract(1)	Index	Currency	Volume	Units	Price
Jan 1, 2024 - Jan 31, 2024	Swap	WTI	USD	80,000	bbl/d	$76.77
Jan 1, 2024 - Jan 31, 2024	Sold Put	WTI	USD	80,000	bbl/d	$60.00
Mar 1, 2024 - May 31, 2024	Swap	WTI	USD	5,000	bbl/d	$48.10
Nov 1, 2023 - Jan 31, 2024	Collar	WTI	USD	10,000	bbl/d	$60.00/$118.95
Feb 1, 2024 - Feb 29, 2024	Collar	WTI	USD	80,000	bbl/d	$60.00/$93.00
Mar 1, 2024 - Mar 31, 2024	Collar	WTI	USD	75,000	bbl/d	$60.00/$105.29
Dec 1, 2024 - Mar 31, 2024	Collar	WTI	USD	18,000	bbl/d	$60.00/$91.01
Feb 1, 2024 - Mar 31, 2024	Collar	WTI	USD	10,000	bbl/d	$60.00/$90.83
Mar 1, 2024 - Aug 31, 2024	Bought Call (2)	WTI	USD	15,739	bbl/d	$165.00
Jan 1, 2024 - Mar 31, 2024	Swap	WTI	CAD	2,000	bbl/d	$111.45
Apr 1, 2024 - Jun 30, 2024	Swap	WTI	CAD	1,750	bbl/d	$109.89
May 1, 2024 - Dec 31, 2024	Swap	WCS	USD	10,000	bbl/d	$(14.25)
Nov 1, 2024 - Apr 30, 2024	Collar	AECO	CAD	120,000	GJ/d	$2.00/$3.63
May 1, 2024 - May 31, 2024	Collar	AECO	USD	60,000	GJ/d	$2.00/$2.27
May 1, 2024 - May 31, 2024	Swap	AECO	USD	60,000	GJ/d	$2.03

(1) For swap contracts, Strathcona receives the fixed price and pays the index. Call options are in-the-money if the index price is above the strike price. For sold calls, Strathcona receives the strike price, and for bought calls, Strathcona pays the strike price. Put options are in-the-money if the index price is below the strike price. For sold puts, Strathcona pays the strike price. For collars, Strathcona receives the floor price if the index is below the floor and the cap price if the index is above the cap.

(2) This contract has a premium of US$13.35/bbl payable over the term of the contract.

(3) The Company has a premium of US$14.45/bbl on expired contracts of 14,400 bbl/d which is payable from March 1, 2024 to August 31, 2024.

The fair value of the Company's risk management contracts as at December 31, 2023 are sensitive to fluctuations in commodity prices. With all other variables held constant, a 10% increase in commodity prices could increase the unrealized loss on risk management contracts by $42.8 million. A 10% decrease in commodity prices could reduce the unrealized loss on risk management contracts by $38.0 million.

Foreign exchange risk

The Company is exposed to fluctuations of the CAD to USD exchange rate given commodity pricing is directly influenced by USD denominated benchmark pricing. In addition, the Company borrows from its Credit Facilities in USD and the Senior Notes are denominated in USD.

The following table summarizes the Company's foreign exchange contracts on revenues as at December 31, 2023:

Term	Contract	USD per Month	CAD/USD Floor	CAD/USD Ceiling
Mar 1, 2024 - Feb 28, 2025	Collar	30.5 million	1.2081	1.2410

Foreign exchange risk on USD denominated Credit Facilities borrowings is eliminated by entering into CCS contracts at the time of a USD borrowing. As part of the CCS, the CAD/USD foreign exchange rate at the beginning and end of the SOFR borrowing term is fixed so the Company does not have any foreign exchange risk on its USD borrowings. As at December 31, 2023, the Company had CCS contracts outstanding totaling:

Notional (US$)	Maturity Date	Contract Price
1,277.9 million	January 12, 2024	CAD/USD 1.3566

The carrying amounts of the Company's USD denominated monetary assets and liabilities exposed to fluctuations in the CAD/USD foreign currency exchange rate are as follows:

As at	December 31, 2023	December 31, 2022
(US$)		
Assets	**58.7**	8.9
Liabilities	**(738.4)**	(521.8)
Net liabilities	**(679.7)**	(512.9)

With all other variables held constant, a $0.01 change in the CAD/USD foreign exchange rate at December 31, 2023 would result in a change in USD denominated monetary assets and liabilities and change annualized net income by $6.8 million (December 31, 2022 – $5.1 million).

Interest rate risk

The Company is exposed to movements in floating interest rates on the Credit Facilities and other liabilities. At December 31, 2023, the following risk management contracts were in place to fix interest rates:

Notional (C$)	Term	Contract	Index	Contract Price
1,500.0 million	May 1, 2023 - Apr 30, 2028	Swap	1 month CDOR	3.4316%

At December 31, 2023, an increase or decrease to interest rates of 50 basis points would result in a $3.6 million impact on annualized interest expense (December 31, 2022 - $12.7 million). The Company is not exposed to interest rate risk on the Senior Notes as they bear a fixed interest rate.

Capital management

The Company's policy is to maintain a strong capital base for the objectives of maintaining financial flexibility, creditor and market confidence and to sustain the future development of the business. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. The Company considers its capital structure to include equity, long-term debt and working capital.

16. COMMITMENTS AND CONTINGENCIES

As at December 31, 2023, the Company is committed to the following non-cancellable payments:

	Total	< 1 year	1-3 years	4-5 years	> 5 years
Transportation and processing commitments	**2,429.1**	303.9	547.0	468.8	1,109.4
Capital commitments	**101.0**	78.8	22.2	—	—
Other	**13.0**	4.3	6.4	2.3	—
Total	**2,543.1**	387.0	575.6	471.1	1,109.4

17. RELATED PARTY TRANSACTIONS

For the year ended December 31, 2023, there were no related party transactions other than key management compensation.

On January 31, 2022, Strathcona exchanged $30.9 million of its shares in its investment in Stickney Resources Ltd. (“**Stickney**”) with an affiliate of WEF (“**WEF Fund II**”) for shares of Caltex Resources Ltd. (“**Caltex**”).

On January 31, 2022, Strathcona issued an unsecured, interest-bearing loan in the amount of $25.0 million to Stickney. The loan was extinguished when Stickney was amalgamated with Strathcona on March 11, 2022.

On March 11, 2022, Strathcona acquired the remaining interests in Caltex and Stickney from WEF Fund II for share consideration valued at $295.8 million and $242.0 million respectively, and amalgamated with the entities.

Prior to the March 11, 2022 amalgamations, the Company provided management and administrative services to Caltex and Stickney. The fees received pursuant to this agreement from January 1, 2022 to March 11, 2022 totaled $0.6 million for Stickney and $1.3 million for Caltex.

Key management personnel of the Company include its officers and directors. Amounts recorded by the Company relating to compensation of directors and officers were as follows:

For the Year Ended December 31,	2023	2022
Key management compensation	**13.4**	10.0

18. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

For the Year Ended December 31,	2023	2022
Source (use) of cash:		
Restricted cash	**—**	8.7
Accounts receivable	**18.6**	(38.6)
Inventory	**17.2**	24.2
Prepaid expenses and deposits	**(9.2)**	(1.6)
Accounts payable and accrued liabilities	**41.6**	264.8
Deferred consideration	**—**	(8.6)
Deferred revenue	**(12.5)**	37.8
	55.7	286.7
Related to operating activities	**4.3**	255.8
Related to financing activities	**0.6**	—
Related to investing activities	**50.8**	30.9

Items not involving cash

For the Year Ended December 31,	2023	2022
Depletion, depreciation and amortization (Note 5)	**732.9**	395.7
Unrealized gain on risk management contracts (Note 15)	**(112.0)**	(90.4)
Unrealized (gain) loss on foreign exchange (Note 12)	**(20.7)**	49.4
Unrealized (gain) loss on Sable remediation fund	**(0.2)**	0.7
Finance costs (Note 11)	**75.3**	29.8
Other income – Decommissioning government grant (Note 8)	**(0.3)**	(5.0)
Share of equity investment income (Note 4)	**—**	(11.3)
Gain on step acquisition of equity method investee (Note 4)	**—**	(132.1)
Gain on termination of lease liability [(1)]	**—**	(0.4)
Deferred tax expense (recovery) (Note 14)	**296.2**	(371.9)
	971.2	(135.5)

(1) For the year ended December 31, 2022, the loss on termination of lease liability recorded in the consolidated statement of comprehensive income of $1.4 million is made up of a non-cash gain on cancellation ($0.4 million) of the lease and an accrued liability in the amount of $1.8 million for costs associated with the cancellation.

19. SEGMENT INFORMATION

The Company has identified three operating segments through examination of the Company's performance which is based on the similarity of services and goods provided and economic characteristics exhibited by the operating segments. The three operating segments are:

- Cold Lake Thermal includes the development and production of bitumen in the Cold Lake region of Northern Alberta.

- Lloydminster Heavy Oil includes the development and production of heavy oil through enhanced oil recovery and thermal steam-assisted gravity drainage ("**SAGD**") methods in Southeast Alberta and Southwest Saskatchewan.

- Montney includes the development and production of liquids rich natural gas produced from the Montney region in Northwest Alberta and Northeast British Columbia.

The Company reports activities not directly attributable to an operating segment under Corporate and Eliminations.

The following tables present the financial performance by reportable segment and includes a measure of segment profit or loss regularly reviewed by management for the noted periods ended December 31, 2023 and 2022.

For the Year Ended December 31,	Cold Lake Thermal 2023	Cold Lake Thermal 2022	Lloydminster Heavy Oil 2023	Lloydminster Heavy Oil 2022	Montney 2023	Montney 2022	Corporate and Eliminations 2023	Corporate and Eliminations 2022	Consolidated 2023	Consolidated 2022
Segment revenues										
Oil and natural gas sales	**2,279.8**	2,358.6	**1,812.8**	1,331.4	**655.5**	672.8	**0.2**	(19.4)	**4,748.3**	4,343.4
Sales of purchased product	**—**	—	**—**	—	**—**	—	**46.3**	64.7	**46.3**	64.7
Royalties	**(323.3)**	(419.0)	**(175.1)**	(151.1)	**(58.5)**	(96.7)	**—**	—	**(556.9)**	(666.8)
Oil and natural gas revenues	**1,956.5**	1,939.6	**1,637.7**	1,180.3	**597.0**	576.1	**46.5**	45.3	**4,237.7**	3,741.3
Segmented expenses										
Purchased product	**—**	—	**—**	—	**—**	—	**46.5**	64.3	**46.5**	64.3
Blending costs	**888.1**	878.6	**170.2**	178.3	**—**	—	**—**	(19.0)	**1,058.3**	1,037.9
Production and operating	**372.3**	378.5	**336.8**	204.4	**87.2**	57.3	**—**	—	**796.3**	640.2
Transportation and processing	**80.4**	69.2	**293.7**	114.4	**108.8**	74.6	**—**	—	**482.9**	258.2
	1,340.8	1,326.3	**800.6**	497.1	**196.0**	131.9	**46.5**	45.3	**2,384.0**	2,000.6
Field operating income	**615.7**	613.3	**837.1**	683.2	**401.0**	444.2	**—**	—	**1,853.7**	1,740.7
(Gain) loss on risk management contracts	**—**	—	**—**	—	**—**	—	**(69.6)**	188.2	**(69.6)**	188.2
Other income	**—**	—	**—**	—	**—**	—	**(1.0)**	(5.3)	**(1.0)**	(5.3)
Acquired inventory	**—**	—	**—**	54.2	**—**	—	**—**	—	**—**	54.2
General and administrative	**—**	—	**—**	—	**—**	—	**91.9**	68.8	**91.9**	68.8
Interest	**—**	—	**—**	—	**—**	—	**206.2**	109.4	**206.2**	109.4
Transaction related costs	**—**	—	**—**	—	**—**	—	**3.8**	11.2	**3.8**	11.2
Finance costs	**—**	—	**—**	—	**—**	—	**75.3**	29.8	**75.3**	29.8
Depletion, depreciation and amortization	**148.9**	120.8	**423.2**	191.2	**145.9**	72.6	**14.9**	11.1	**732.9**	395.7
Foreign exchange (gain) loss	**—**	—	**—**	—	**—**	—	**(22.1)**	43.7	**(22.1)**	43.7
Unrealized (gain) loss on Sable remediation fund	**—**	—	**—**	—	**—**	—	**(0.2)**	0.7	**(0.2)**	0.7
Share of equity investment income	**—**	—	**—**	—	**—**	—	**—**	(11.3)	**—**	(11.3)
Gain on step acquisitions of equity method investees	**—**	—	**—**	—	**—**	—	**—**	(132.1)	**—**	(132.1)
Loss on termination of lease liability	**—**	—	**—**	—	**—**	—	**—**	1.4	**—**	1.4
Income before income taxes									**836.5**	986.3
Current tax (recovery)									**(46.9)**	—
Deferred tax expense (recovery)									**296.2**	(371.9)
Income and comprehensive income									**587.2**	1,358.2

For the Year Ended December 31,	Cold Lake Thermal		Lloydminster Heavy Oil		Montney		Corporate and Eliminations		Consolidated	
	2023	2022	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022
Capital expenditures	**306.0**	256.2	**360.5**	160.2	**351.0**	201.5	**10.9**	3.0	**1,028.4**	620.9
Decommissioning costs(1)	**1.8**	2.2	**20.7**	7.4	**15.7**	13.6	**—**	—	**38.2**	23.2

(1) Decommissioning costs include amounts granted to the Company through the Site Rehabilitation Program (Alberta), Dormant Sites Reclamation Program (British Columbia) and the Accelerated Site Closure Program (Saskatchewan) to pay service companies to complete abandonment and reclamation work.

20. SUBSEQUENT EVENT

On March 25, 2024, Strathcona received approval from its lenders to increase the Revolving Credit Facility to $2.5 billion and to extend the maturity date to four years from closing. Closing is subject to completion of documentation, and is anticipated to occur on or about March 28, 2024.

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