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")

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2023**	December 31, 2022	September 30, 2023	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")

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2023**	December 31, 2022	September 30, 2023	**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

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2023**	December 31, 2022	September 30, 2023	**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.

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2023**	December 31, 2022	September 30, 2023	**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.

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2023**	December 31, 2022	September 30, 2023	**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

	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	**(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.