STRATHCONA RESOURCES LTD

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE MONTHS ENDED MARCH 31, 2024 AND 2023

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 May 14, 2024 and should be read in conjunction with the Company's unaudited condensed consolidated interim financial statements (and related notes) as at and for the three months ended March 31, 2024 and 2023 (the "**interim financial statements**") and the Company's audited consolidated financial statements (and related notes) for the years ended December 31, 2023 and December 31, 2022 (the "**annual financial statements**"). The interim financial statements and 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 interim financial statements and 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 "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 Resources Ltd., a predecessor of the Company, and Pipestone Energy Corp. ("**Pipestone**") on October 3, 2023 (the "**Pipestone Acquisition**"), as part of 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., and commencing on October 3, 2023 also reflects the results of Pipestone.

The significant differences in financial and operational results of the Company for the three months ended March 31, 2024 compared to the three months ended March 31, 2023 within this MD&A are primarily the result of the Pipestone Acquisition. Refer to Note 4 of the annual financial statements for further details regarding the Pipestone Acquisition.

At March 31, 2024, approximately 90.8% of the Company's shares were owned by certain limited partnerships comprising Waterous Energy Fund and its affiliates (collectively, "**WEF**").

PRODUCTION VOLUMES

	Three Months Ended		
	March 31, 2024	March 31, 2023	December 31, 2023
Bitumen (bbl/d)	**60,150**	51,097	59,845
Heavy oil (bbl/d)	**51,835**	57,443	52,736
Condensate and light oil (bbl/d)	**19,279**	8,068	19,184
Total oil production (bbl/d)	**131,264**	116,608	131,765
Other NGLs (bbl/d)	**11,738**	8,501	11,906
Natural gas (mcf/d)	**252,720**	114,304	254,361
Total (boe/d)	**185,122**	144,160	186,064
% oil and condensate	**71 %**	81 %	71 %
% liquids	**77 %**	87 %	77 %

Production volumes increased by 40,962 boe per day for the three months ended March 31, 2024 to an average of 185,122 boe per day compared to 144,160 boe per day for the same quarter of 2023. 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 production of 34,003 boe per day in the three months ended March 31, 2024, composed of condensate and light oil production of 9,862 bbl per day, other NGLs of 3,590 bbl per day and natural gas of 123,308 mcf per day in the three months ended March 31, 2024. The remaining production increase is attributable to strong well results from the 2023 capital program.

Production volumes were relatively unchanged during the three months ended March 31, 2024 compared to the three months ended December 31, 2023.

2024 production guidance remains unchanged at 187,500 boe per day to 192,500 boe per day.

SALES VOLUMES

	Three Months Ended		
	March 31, 2024	March 31, 2023	December 31, 2023
Bitumen (bbl/d)	**60,422**	51,135	60,027
Heavy oil (bbl/d)	**49,303**	60,122	50,849
Condensate and light oil (bbl/d)	**19,279**	8,068	19,184
Total oil production (bbl/d)	**129,004**	119,325	130,060
Other NGLs (bbl/d)	**11,738**	8,501	11,906
Natural gas (mcf/d)	**252,720**	114,304	254,361
Total (boe/d)	**182,862**	146,877	184,360

Sales volumes will trend with production volumes, except in cases of an inventory build or an inventory draw. Strathcona carries inventory on rail cars in transit to the US Gulf Coast, on pipelines and in storage tanks. At March 31, 2024 heavy oil inventory volumes on rail increased due to a delay in the commissioning of an expansion to a unit train offloading facility on the US Gulf Coast. The facility was purpose-built for Strathcona to better supply a local US Gulf Coast refiner that entered into a new crude purchase agreement with the Company at a premium to WCS Houston. The facility is now fully operational and the volumes in inventory at March 31, 2024 will be released from inventory over the balance of 2024.

BUSINESS ENVIRONMENT

	Three Months Ended		
	March 31, 2024	March 31, 2023	December 31, 2023
Benchmark Pricing			
US$/bbl unless otherwise indicated			
WTI(1)	**76.96**	76.13	78.32
WCS Hardisty(2)	**57.65**	51.25	56.43
WCS USGC(3)	**69.89**	62.48	71.59
WTI-WCS Hardisty differential	**(19.31)**	(24.88)	(21.89)
WTI-WCS USGC differential	**(7.07)**	(13.65)	(6.73)
NYMEX-AECO differential (US$/MMbtu)(4)	**(0.88)**	(0.53)	(1.13)
Condensate differential(5)	**(4.18)**	3.70	(2.09)
Average FX rate (C$/US$)	**1.3488**	1.3520	1.3618
CAD$/bbl unless otherwise indicated			
WTI(1)	**103.81**	102.91	106.72
WCS Hardisty(2)	**77.77**	69.31	76.85
WCS USGC(3)	**94.28**	84.46	97.49
AECO 5A (C$/mcf)(6)	**2.50**	3.22	2.30
Condensate par at Edmonton	**98.18**	107.92	103.81
AESO weighted average pool price (C$/MWh)(7)	**100.96**	143.00	83.05
CORRA (%)(8)	**5.03**	4.44	5.03
CDOR (%)(9)	**5.36**	4.88	5.41

(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 Overnight Repo Rate Average ("CORRA").
(9) Canadian Dollar Offered Rate ("CDOR") percentage for 1 month tenors.

WTI crude oil prices decreased 2% in the first quarter of 2024 compared to the fourth quarter of 2023 as there was a slowing of global oil demand growth and increased supply growth outside of OPEC+, driven by the US. The supply growth outside of OPEC+ offset additional OPEC+ production curtailments that were implemented for the first quarter of 2024.

The WTI-WCS Hardisty differential narrowed 12% in the first quarter of 2024 compared to the fourth quarter of 2023 and has continued to narrow in anticipation of the Trans Mountain Pipeline Expansion Project, which came online on May 1, 2024. The expansion will add approximately 590,000 bbl per day of heavy oil blend transport capacity to the existing system and is anticipated to improve pipeline economics for the WCS Hardisty barrel.

The WTI-WCS USGC differential was impacted by the same factors described above in the first quarter of 2024. Additionally, strong demand from US refiners in the USGC region due to favorable heavy sour refining economics and the anticipation of Mexican imported heavy barrels being displaced from the USGC in 2024 as Pemex opens a new refinery, supported a narrowing of the USGC WCS differential to WTI in the first quarter of 2024 compared to December of 2023.

AECO 5A natural gas prices increased 9% in the first quarter of 2024 compared to the fourth quarter of 2023. While Canadian gas production remained high in the first quarter of 2024 and is expected to grow to a record annual average, 2024 is also expected to see the startup of LNG Canada mid-year which will provide 1.84 Bcf per day of export capacity in its first phase. 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. In the fourth quarter of 2023, a warm start to the winter season put further downward pressure on natural gas prices, but recovered modestly in the first quarter of 2024 due to periods of unseasonably cold weather that increased gas demand.

REVENUE AND REALIZED PRICES

Oil and Natural Gas Sales - Net of Blending

	Three Months Ended		
($ millions, unless otherwise indicated)	**March 31, 2024**	March 31, 2023	December 31, 2023
Bitumen blend	**623.7**	470.2	591.8
Heavy oil, blended and raw	**416.5**	447.7	437.3
Condensate and light oil	**165.8**	73.5	172.3
Other natural gas liquids	**30.3**	22.0	26.9
Natural gas	**62.5**	34.3	59.3
Oil and natural gas sales	**1,298.8**	1,047.7	1,287.6
Gain (loss) purchased product	**—**	(1.0)	1.0
Bitumen - blending cost	**(251.8)**	(236.0)	(243.5)
Heavy oil - blending cost	**(42.8)**	(49.2)	(41.3)
Oil and natural gas sales - net of blending[1]	**1,004.2**	761.5	1,003.8

(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 32% for the three months ended March 31, 2024 to $1,004.2 million compared to $761.5 million for the same quarter in 2023. This increase is primarily attributable to: increased sales volumes from the Cold Lake Thermal segment and the properties acquired in the Pipestone Acquisition; stronger benchmark pricing due to the narrowing of WCS differentials; and lower per barrel blending costs due to lower condensate benchmark pricing.

Oil and natural gas sales, net of blending, for the three months ended March 31, 2024 remained consistent with the three months ended December 31, 2023.

Average Realized Prices

	Three Months Ended		
	March 31, 2024	March 31, 2023	December 31, 2023
Bitumen blend ($/bbl)[1][2]	**67.66**	50.66	63.07
Heavy oil, blended and raw ($/bbl)[1][2]	**83.29**	73.65	84.23
Condensate and light oil ($/bbl)	**94.50**	101.28	97.62
Realized oil ($/bbl)	**77.64**	65.66	76.46
Other natural gas liquids ($/bbl)	**28.37**	28.72	24.56
Natural gas ($/mcf)	**2.72**	3.34	2.53
Combined ($/boe)	**60.35**	57.53	59.17

(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 increased 5% for the three months ended March 31, 2024 to $60.35 per boe compared to $57.53 per boe in the same quarter of 2023. The increase is primarily attributable to a narrower WTI-WCS Hardisty and USGC differentials and lower condensate benchmark prices which reduces the per boe blending cost associated with bitumen blend and heavy oil, blended.

Combined realized price increased 2% for the three months ended March 31, 2024 to $60.35 per boe compared to $59.17 per boe for the three months ended December 31, 2023. The increase is primarily attributable to lower condensate benchmark prices which reduces per boe blending costs, partially offset by a reduction in heavy oil, blended and raw pricing due to lower WCS USGC benchmark prices.

ROYALTIES

($ millions, unless otherwise indicated)	Three Months Ended **March 31, 2024**	March 31, 2023	December 31, 2023
Crown royalties	**94.6**	95.5	96.3
Freehold royalties	**13.2**	10.8	14.0
Gross overriding royalties	**14.4**	6.1	17.2
Other royalties	**4.0**	0.7	7.4
Royalties	**126.2**	113.1	134.9
Effective royalty rate (%)(1)	**12.6 %**	14.9 %	13.4 %

(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 March 31, 2024, the average effective royalty rate was 12.6% compared to 14.9% for the same period in 2023.

For the three months ended March 31, 2024, the average effective royalty rate decreased to 12.6% from 13.4% in the fourth quarter of 2023.

These decreases were primarily the result of royalty recoveries for Oil Sands Royalty ("**OSR**") capital expansion applications submitted during the first quarter of 2024 which permitted the deduction of previously excluded costs.

PRODUCTION AND OPERATING EXPENSES

($ millions, unless otherwise indicated)	Three Months Ended **March 31, 2024**	March 31, 2023	December 31, 2023
Production and operating - Energy	**78.8**	88.7	72.5
Production and operating - Non-energy	**135.4**	115.9	133.3
Production and operating expenses	**214.2**	204.6	205.8
Production and operating - Energy ($/boe)	**4.74**	6.71	4.27
Production and operating - Non-energy ($/boe)	**8.14**	8.77	7.86
Production and operating expenses ($/boe)	**12.88**	15.48	12.13

Production and operating expenses increased to $214.2 million ($12.88 per boe) for the three month period ended March 31, 2024 from $204.6 million ($15.48 per boe) in the same period of 2023. This increase is primarily attributable to higher non-energy production and operating costs predominantly related to the Pipestone Acquisition, which added $22.5 million in incremental non-energy costs in the current three month period, partially offset by decreased energy costs as a result of lower natural gas and power prices. On a per boe basis, production and operating expenses were lower in the current period due to the incremental production from the Pipestone Acquisition assets, which generally have a lower production and operating cost structure compared to the Cold Lake Thermal and Lloydminster Heavy Oil segments.

Energy related production and operating expenses increased during the three months ended March 31, 2024 compared to the three months ended December 31, 2023 due to increased energy costs from higher natural gas and power prices.

On a per boe basis, non-energy production and operating costs increased to $8.14 per boe for the three months ended March 31, 2024 from $7.86 per boe for the three months ended December 31, 2023 due to higher water management and disposal costs incurred during the first quarter of 2024.

TRANSPORTATION AND PROCESSING EXPENSES

	Three Months Ended		
($ millions, unless otherwise indicated)	**March 31, 2024**	March 31, 2023	December 31, 2023
Transportation expenses	**114.8**	120.7	109.7
Processing expenses	**28.6**	7.2	26.0
Transportation and processing expenses	**143.4**	127.9	135.7
$ per boe	**8.62**	9.68	8.00

Transportation expenses decreased by 5% to $114.8 million for the three months ended March 31, 2024 from $120.7 million in the same period of 2023. This decrease was primarily attributable to the lower sales volumes transported by rail in the three month period ended March 31, 2024, which has a higher transportation cost per barrel compared to sales volumes transported by pipeline. Processing expenses increased to $28.6 million for the three months ended March 31, 2024 from $7.2 million in the same period of 2023. This increase was primarily attributable to the Pipestone Acquisition which resulted in additional processing expenses with flow-through capital charges, as the majority of the production is processed through third party facilities.

Transportation and processing expenses increased by 6% for the three months ended March 31, 2024 to $143.4 million ($8.62 per boe) from $135.7 million ($8.00 per boe) in the fourth quarter of 2023. The fourth quarter of 2023 benefited from cost savings on make-up rights related to fixed transportation contracts in the Cold Lake Thermal segment and reduced capital fees on processing contracts in the Montney segment as a result of unscheduled downtime. In addition there was an increase in production from the properties acquired in the Pipestone Acquisition in the first quarter of 2024 which carry higher per barrel transportation and processing costs compared to legacy fields in the Montney segment.

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

	Three Months Ended		
($ millions, unless otherwise indicated)	**March 31, 2024**	March 31, 2023	December 31, 2023
Depletion expense	**208.9**	157.1	214.8
Depreciation and amortization expense	**12.9**	6.0	12.7
DD&A	**221.8**	163.1	227.5
$ per boe	**13.33**	12.34	13.41

DD&A expense increased 36% for the three months ended March 31, 2024 to $221.8 million ($13.33 per boe) compared to $163.1 million ($12.34 per boe) for the same quarter of 2023. This increase was primarily due to a higher DD&A rate as well as increased production volumes.

DD&A expense decreased 3% for the three months ended March 31, 2024 to $221.8 million ($13.33 per boe) compared to $227.5 million ($13.41 per boe) for the three months ended December 31, 2023. This is predominantly due to an increase in volumes in transit to the USGC at the end of the first quarter 2024 resulting in decreased sales volumes.

GENERAL AND ADMINISTRATION EXPENSES (“G&A”)

($ millions, unless otherwise indicated)	Three Months Ended **March 31, 2024**	March 31, 2023	December 31, 2023
G&A expenses	**22.0**	25.9	24.5
$ per boe	**1.32**	1.96	1.44

For the three months ended March 31, 2024, G&A expenses decreased to $22.0 million ($1.32 per boe) from $25.9 million ($1.96 per boe) in the same period in 2023. The decrease was primarily due to lower personnel costs compared to the same period of 2023.

G&A expenses decreased during the three months ended March 31, 2024 to $22.0 million ($1.32 per boe) from $24.5 million ($1.44 per boe) for three months ended December 31, 2023 primarily due to lower information systems and consultant costs.

INTEREST

($ millions, unless otherwise indicated)	Three Months Ended **March 31, 2024**	March 31, 2023	December 31, 2023
Interest expense	**45.4**	54.1	51.6
Weighted average interest rate (%)	**6.4 %**	6.9 %	6.7 %

Interest expense decreased 16% for the three months ended March 31, 2024 to $45.4 million compared to $54.1 million for the same quarter of 2023. Interest expense decreased 12% for the three months ended March 31, 2024 to $45.4 million compared to $51.6 million for the fourth quarter of 2023. These decreases are primarily the result of lower debt levels and lower interest rates as a result of interest rate swaps.

During the three months ended March 31, 2024, the Company recorded $11.6 million in interest expense on the Senior Notes (as defined in the "Capital Resources" section of this MD&A) (March 31, 2023 – $11.6 million); and $41.0 million in interest expense on the bank credit facilities (March 31, 2023 - $42.5 million); and a realized gain of $7.2 million on interest rate swaps (March 31, 2023 - nil).

The impact of higher interest rates is partially mitigated through interest rate swaps, see the "*Risk Management - Market Risk - Interest Rate Risk*" section of this MD&A.

FINANCE COSTS

($ millions, unless otherwise indicated)	Three Months Ended **March 31, 2024**	March 31, 2023	December 31, 2023
Accretion of lease obligations	**6.2**	2.8	5.9
Accretion of decommissioning provision	**7.1**	7.2	7.1
Amortization of debt issuance costs	**4.1**	3.2	3.5
Accretion of other obligations	**4.9**	4.6	5.1
Finance costs	**22.3**	17.8	21.6

For the three months ended March 31, 2024, finance costs increased by 25% to $22.3 million compared to $17.8 million in the same quarter of 2023. This increase is due to higher accretion of lease obligations as a result of contracts assumed in the Pipestone Acquisition and higher amortization of debt issuance costs as a result of fees incurred on the increase of the Revolving Credit Facility. Refer to the Capital Resources section of this MD&A for further details.

Finance costs increased 3% for the three months ended March 31, 2024 to $22.3 million compared to $21.6 million for the three months ended December 31, 2023. This is predominantly due to higher amortization of debt issuance costs as a result of fees incurred on the increase of the Revolving Credit Facility. Refer to the Capital Resources section of this MD&A for further details.

TAX POOLS

As at March 31, 2024, the Company had approximately $5,942.8 million (December 31, 2023 - $6,081.1 million) of tax pools available for deduction in future periods as shown in the table below.

($ millions, unless otherwise indicated)	Annual Pool Deduction Rate	**March 31, 2024**	December 31, 2023
Canadian oil and gas property expenditures	10 %	**874.2**	893.4
Canadian development expenditures(1)	30 %	**1,230.7**	1,168.8
Canadian exploration expenditures(1)	100 %	**32.3**	34.1
Undepreciated capital costs(2)	4 % - 55 %	**1,385.7**	1,371.0
Non-capital losses	100 %	**1,983.9**	2,173.1
Other(3)		**436.0**	440.7
Total tax pools		**5,942.8**	6,081.1

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

(2) As at March 31, 2024, approximately 97% (December 31, 2023 – 96%) 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 March 31, 2024, approximately 87% (December 31, 2023 – 89%) 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
Apr 1, 2024 - June 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)
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. 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 Revolving Credit Facility in USD and the Senior Notes are denominated in USD. The Company actively manages foreign exchange risk using foreign exchange derivatives.

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 Revolving Credit Facility 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(1)	3.4316%(1)

(1) Following the CDOR cessation date on June 28, 2024, the interest rate swaps fix CORRA at 3.1357%.

For a listing of the Company's commodity contracts, foreign exchange and interest rate contracts outstanding as at March 31, 2024 refer to Note 11 in the interim 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		
($ millions, unless otherwise indicated)	**March 31, 2024**	March 31, 2023	December 31, 2023
Realized (gain) loss on risk management contracts[1]	**(4.5)**	5.4	(19.5)
Unrealized loss (gain) on risk management contracts[2]	**44.2**	(69.6)	(109.6)
Total loss (gain) on risk management contracts	**39.7**	(64.2)	(129.1)
Realized (gain) loss on risk management contract per boe	**(0.27)**	0.41	(1.15)

(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 $4.5 million for the three months ended March 31, 2024 compared to a loss of $5.4 million and a gain of $19.5 million for the three months ended March 31, 2023 and December 31, 2023, respectively. The realized gains on risk management contracts are due to realized commodity benchmark prices in comparison to contracted hedge pricing.

As at March 31, 2024, the mark-to-market value of risk management contracts was a net liability of $147.9 million (December 31, 2023 - net liability of $103.7 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 11 to the interim financial statements.

TRANSACTION RELATED COSTS

	Three Months Ended		
($ millions, unless otherwise indicated)	**March 31, 2024**	March 31, 2023	December 31, 2023
Transaction related (recoveries) costs	**0.1**	1.2	(1.3)

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		
($ millions, unless otherwise indicated)	**March 31, 2024**	March 31, 2023	December 31, 2023
Cold Lake Thermal	**58.9**	79.0	69.7
Lloydminster Heavy Oil	**95.7**	85.0	96.2
Montney	**129.9**	61.4	139.3
Corporate	**1.6**	3.3	2.6
Capital expenditures	**286.1**	228.7	307.8

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

	Three Months Ended		
($ millions, unless otherwise indicated)	**March 31, 2024**	March 31, 2023	December 31, 2023
Drilling, completion and equipping	**165.4**	134.0	177.3
Facilities and pipelines	**74.3**	67.9	96.5
Recompletion, workovers and polymer powder	**29.0**	14.8	19.2
Capitalized G&A and other expenditures	**17.4**	12.0	14.8
Capital expenditures	**286.1**	228.7	307.8

For the three months ended March 31, 2024, drilling, completion and equipping activities accounted for 58% of capital expenditures as the Company drilled 68 new wells during the quarter; 9 in Cold Lake Thermal, 50 in Lloydminster Heavy Oil and 9 in Montney.

Capital expenditures increased 25% for the three months ended March 31, 2024 to $286.1 million compared to $228.7 million for the same quarter of 2023. This increase is primarily the result of $45.3 million of capital spending on the assets acquired through the Pipestone Acquisition.

Capital expenditures decreased 7% for the three months ended March 31, 2024 to $286.1 million compared to $307.8 million for the fourth quarter of 2023. While timing of the expenditures in the 2024 program will vary from quarter to quarter, full year capital guidance remains unchanged at $1.3 billion.

FOREIGN EXCHANGE

	Three Months Ended		
($ millions, unless otherwise indicated)	**March 31, 2024**	March 31, 2023	December 31, 2023
Realized loss (gain)	**2.0**	0.2	(0.1)
Unrealized loss (gain) - Senior Notes	**14.9**	(1.9)	(16.8)
Unrealized loss (gain) - Credit Facility	**50.1**	(25.7)	(38.0)
Unrealized (gain) loss - cross-currency swaps	**(49.5)**	22.3	36.7
Unrealized loss (gain) - other	**2.9**	(0.8)	(2.7)
Foreign Exchange loss (gain)	**20.4**	(5.9)	(20.9)

Foreign exchange for the three months ended March 31, 2024 resulted in a loss of $20.4 million compared to a gain of $5.9 million and a gain of $20.9 million for the three month periods ending March 31, 2023 and December 31, 2023, respectively. 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".

For the Three Months Ended	Cold Lake Thermal Segment			Lloydminster Heavy Oil Segment			Montney Segment			Corporate			Consolidated		
	Mar 31, 2024	Mar 31, 2023	Dec 31, 2023	**Mar 31, 2024**	Mar 31, 2023	Dec 31, 2023	**Mar 31, 2024**	Mar 31, 2023	Dec 31, 2023	**Mar 31, 2024**	Mar 31, 2023	Dec 31, 2023	**Mar 31, 2024**	Mar 31, 2023	Dec 31, 2023
Production volumes															
Bitumen (bbl/d)	**60,150**	51,097	59,845	**—**	—	—	**—**	—	—	**—**	—	—	**60,150**	51,097	59,845
Heavy oil (bbl/d)	**—**	—	—	**51,835**	57,443	52,736	**—**	—	—	**—**	—	—	**51,835**	57,443	52,736
Condensate and light oil (bbl/d)	**—**	—	—	**46**	46	40	**19,233**	8,022	19,144	**—**	—	—	**19,279**	8,068	19,184
Other NGLs (bbl/d)	**—**	—	—	**2**	2	1	**11,736**	8,499	11,905	**—**	—	—	**11,738**	8,501	11,906
Natural gas (mcf/d)	**—**	—	—	**1,254**	895	1,260	**251,466**	113,409	253,101	**—**	—	—	**252,720**	114,304	254,361
Production volumes (boe/d)	**60,150**	51,097	59,845	**52,092**	57,641	52,987	**72,880**	35,422	73,232	**—**	—	—	**185,122**	144,160	186,064
Sales volumes (boe/d)	**60,422**	51,135	60,027	**49,560**	60,320	51,100	**72,880**	35,422	73,232	**—**	—	—	**182,862**	146,877	184,360
Segment revenues															
Oil and natural gas sales	**623.8**	468.6	592.0	**417.0**	449.4	437.8	**258.0**	129.0	257.8	**—**	0.7	—	**1,298.8**	1,047.7	1,287.6
Sales of purchased products	**1.0**	3.2	8.1	**—**	2.7	3.2	**—**	—	—	**1.0**	7.9	—	**2.0**	13.8	11.3
Blending costs	**(251.8)**	(234.6)	(243.5)	**(42.8)**	(50.6)	(41.3)	**—**	—	—	**—**	—	—	**(294.6)**	(285.2)	(284.8)
Purchased product	**(1.0)**	(3.5)	(7.3)	**—**	(2.7)	(3.0)	**—**	—	—	**(1.0)**	(8.6)	—	**(2.0)**	(14.8)	(10.3)
Oil and natural gas sales, net of blending[(1)]	**372.0**	233.7	349.3	**374.2**	398.8	396.7	**258.0**	129.0	257.8	**—**	—	—	**1,004.2**	761.5	1,003.8
Segment expenses															
Royalties	**57.1**	48.9	73.8	**42.8**	42.9	41.7	**26.3**	21.3	19.4	**—**	—	—	**126.2**	113.1	134.9
Production and operating - Energy	**43.8**	55.2	39.6	**33.8**	32.6	31.4	**1.2**	0.9	1.5	**—**	—	—	**78.8**	88.7	72.5
Production and operating - Non-energy	**48.0**	44.3	44.9	**45.5**	57.3	50.6	**41.9**	14.3	37.8	**—**	—	—	**135.4**	115.9	133.3
Transportation and processing	**21.6**	19.0	18.7	**65.2**	89.7	65.4	**56.6**	19.2	51.6	**—**	—	—	**143.4**	127.9	135.7
Field Operating Income[(1)]	**201.5**	66.3	172.3	**186.9**	176.3	207.6	**132.0**	73.3	147.5	**—**	—	—	**520.4**	315.9	527.4
Depletion, depreciation and amortization	**42.9**	29.9	42.9	**99.1**	107.3	103.5	**76.0**	22.7	76.7	**3.8**	3.2	4.4	**221.8**	163.1	227.5
Field Operating Earnings[(1)]	**158.6**	36.4	129.4	**87.8**	69.0	104.1	**56.0**	50.6	70.8	**(3.8)**	(3.2)	(4.4)	**298.6**	152.8	299.9
General and administrative	**—**	—	—	**—**	—	—	**—**	—	—	**22.0**	25.9	24.5	**22.0**	25.9	24.5
Other income	**—**	—	—	**—**	—	—	**—**	—	—	**(0.1)**	—	0.1	**(0.1)**	—	0.1
Interest expense	**—**	—	—	**—**	—	—	**—**	—	—	**45.4**	54.1	51.6	**45.4**	54.1	51.6
Finance costs	**—**	—	—	**—**	—	—	**—**	—	—	**22.3**	17.8	21.6	**22.3**	17.8	21.6
Current income tax (recovery)	**—**	—	—	**—**	—	—	**—**	—	—	**—**	(46.9)	—	**—**	(46.9)	—
Operating Earnings[(1)]													**209.0**	101.9	202.1
(Gain) loss on risk management contracts - realized	**—**	—	—	**—**	—	—	**—**	—	—	**(4.5)**	5.4	(19.5)	**(4.5)**	5.4	(19.5)
Loss (gain) on risk management contracts - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**44.2**	(69.6)	(109.6)	**44.2**	(69.6)	(109.6)
Foreign exchange loss (gain) - realized	**—**	—	—	**—**	—	—	**—**	—	—	**2.0**	0.2	(0.1)	**2.0**	0.2	(0.1)
Foreign exchange loss (gain) - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**18.4**	(6.1)	(20.8)	**18.4**	(6.1)	(20.8)
Transaction related costs (recoveries)	**—**	—	—	**—**	—	—	**—**	—	—	**0.1**	1.2	(1.3)	**0.1**	1.2	(1.3)
Unrealized loss (gain) on Sable remediation fund	**—**	—	—	**—**	—	—	**—**	—	—	**0.1**	(0.2)	(0.3)	**0.1**	(0.2)	(0.3)
Deferred tax expense	**—**	—	—	**—**	—	—	**—**	—	—	**48.1**	80.5	90.0	**48.1**	80.5	90.0
Income and comprehensive income													**100.6**	90.5	263.7

(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			Consolidated		
	Mar 31, 2024	Mar 31, 2023	Dec 31, 2023	**Mar 31, 2024**	Mar 31, 2023	Dec 31, 2023	**Mar 31, 2024**	Mar 31, 2023	Dec 31, 2023	**Mar 31, 2024**	Mar 31, 2023	Dec 31, 2023	**Mar 31, 2024**	Mar 31, 2023	Dec 31, 2023
Segment revenues															
Oil and natural gas sales	**77.80**	69.88	76.01	**85.78**	77.57	86.86	**38.90**	40.46	38.26	**—**	0.05	—	**66.57**	66.63	65.82
Sales of purchased products	**0.18**	0.70	1.47	**—**	0.50	0.68	**—**	—	—	**0.06**	0.60	—	**0.12**	1.04	0.67
Blending costs	**(10.14)**	(19.03)	(12.90)	**(2.81)**	(4.11)	(2.52)	**—**	—	—	**—**	—	—	**(6.22)**	(9.02)	(6.71)
Purchased product	**(0.18)**	(0.76)	(1.32)	**—**	(0.50)	(0.64)	**—**	—	—	**(0.06)**	(0.65)	—	**(0.12)**	(1.12)	(0.61)
Oil and natural gas sales, net of blending[1]	**67.66**	50.78	63.25	**82.97**	73.46	84.38	**38.90**	40.46	38.26	**—**	—	—	**60.35**	57.53	59.17
Segment expenses															
Royalties	**10.38**	10.63	13.36	**9.49**	7.90	8.87	**3.97**	6.68	2.88	**—**	—	—	**7.58**	8.55	7.95
Production and operating - Energy	**7.97**	11.99	7.17	**7.49**	6.00	6.68	**0.18**	0.28	0.22	**—**	—	—	**4.74**	6.71	4.27
Production and operating - Non-energy	**8.73**	9.63	8.13	**10.09**	10.55	10.76	**6.32**	4.49	5.61	**—**	—	—	**8.14**	8.77	7.86
Transportation and processing	**3.93**	4.13	3.39	**14.46**	16.52	13.91	**8.53**	6.02	7.66	**—**	—	—	**8.62**	9.68	8.00
Field Operating Netback[1]	**36.65**	14.40	31.20	**41.44**	32.49	44.16	**19.90**	22.99	21.89	**—**	—	—	**31.27**	23.82	31.09
Depletion, depreciation and amortization	**7.80**	6.49	7.77	**21.97**	19.76	22.02	**11.46**	7.12	11.38	**0.23**	0.24	0.26	**13.33**	12.34	13.41
Field Operating Earnings Netback[1]	**28.84**	7.91	23.43	**19.46**	12.73	22.14	**8.44**	15.87	10.51	**(0.23)**	(0.24)	(0.26)	**17.94**	11.48	17.68
General and administrative	**—**	—	—	**—**	—	—	**—**	—	—	**1.32**	1.96	1.44	**1.32**	1.96	1.44
Other (income) expense	**—**	—	—	**—**	—	—	**—**	—	—	**(0.01)**	—	0.01	**(0.01)**	—	0.01
Interest expense	**—**	—	—	**—**	—	—	**—**	—	—	**2.73**	4.09	3.04	**2.73**	4.09	3.04
Finance costs	**—**	—	—	**—**	—	—	**—**	—	—	**1.34**	1.35	1.27	**1.34**	1.35	1.27
Current income tax (recovery)	**—**	—	—	**—**	—	—	**—**	—	—	**—**	(3.55)	—	**—**	(3.55)	—
Operating Earnings [1]													**12.56**	7.63	11.92
Effective royalty rate (%)[1]	**15.3**	20.9	21.1	**11.4**	10.8	10.5	**10.2**	16.5	7.5				**12.6**	14.9	13.4

(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 March 31, 2024, increased to 60,150 boe per day from 51,097 boe per day compared to the same quarter of 2023. The increase in production is primarily due to production brought on as a result of the 2023 capital program and improved base production performance at the Company's Lindbergh and Tucker properties.

Oil and natural gas sales, net of blending, increased to $372.0 million ($67.66 per boe) during the three months ended March 31, 2024 compared to $233.7 million ($50.78 per boe) for the same quarter of 2023. The increase is primarily due to higher sales volumes, stronger benchmark pricing due to the narrowing of the WCS Hardisty differential and lower per barrel blending costs due to lower condensate benchmark pricing.

The effective royalty rate for the three months ended March 31, 2024 decreased to 15.3% from 20.9% in the same quarter of 2023. This decrease is primarily the result of royalty recoveries for OSR capital expansion applications submitted during the first quarter of 2024 which permitted the deduction of previously deferred costs.

Energy related production and operating expenses for the three months ended March 31, 2024 decreased to $43.8 million ($7.97 per boe) from $55.2 million ($11.99 per boe) in the same quarter of 2023. This decrease is primarily attributable to the lower price of natural gas and electricity in the first quarter of 2024.

For the three months ended March 31, 2024, non-energy related production and operating expenses increased to $48.0 million ($8.73 per boe) from $44.3 million ($9.63 per boe) in the same quarter of 2023. This increase is primarily due to higher labour, chemical, processing and handling fees as a result of higher production volume.

For the three months ended March 31, 2024, transportation and processing increased to $21.6 million ($3.93 per boe) from $19.0 million ($4.13 per boe) in the same quarter of 2023. The increase is primarily due to increased production volumes.

Lloydminster Heavy Oil

Production for the Lloydminster Heavy Oil segment for the three months ended March 31, 2024, decreased to 52,092 boe per day from 57,641 boe per day in the same period of 2023. This decrease is primarily due to lower production volumes from Saskatchewan thermal properties.

Oil and natural gas sales, net of blending, decreased to $374.2 million ($82.97 per boe) during the three months ended March 31, 2024 compared to $398.8 million ($73.46 per boe) for the same period of 2023. The decrease is primarily due to lower sales volumes, partially offset by higher WCS benchmark commodity prices in the current period.

The increase in benchmark commodity prices also impacted royalties. The effective royalty rate for the three months ended March 31, 2024 increased to 11.4% from 10.8% in the same period of 2023.

Energy related production and operating expenses for the three months ended March 31, 2024 increased to $33.8 million ($7.49 per boe) from $32.6 million ($6.00 per boe) for the same period in 2023. The increase is primarily attributable to carbon tax charges as the Company was over the baseline emissions for the Lloydminster Heavy Oil segment in the first quarter of 2024, but under the baseline emissions in the first quarter of 2023, offset by lower natural gas prices.

Non-energy related production and operating expenses for the three months ended March 31, 2024 decreased to $45.5 million ($10.09 per boe) from $57.3 million ($10.55 per boe) in the same period of 2023. The decrease is primarily due to lower sales volumes during the current period.

For the three months ended March 31, 2024, transportation and processing decreased to $65.2 million ($14.46 per boe) from $89.7 million ($16.52 per boe) in the same quarter of 2023. The decrease is primarily due to lower sales volumes and a lower proportion of sales that were transported by rail, resulting in a lower transportation costs per barrel compared to volumes transported by rail.

Montney

Production at the Company's Montney segment for the three months ended March 31, 2024 increased to 72,880 boe per day from 35,422 boe per day in the same period of 2023. The increase is primarily due to production of 34,004 boe per day from properties added through the Pipestone Acquisition, which was completed in the fourth quarter of 2023.

For the three months ended March 31, 2024, oil and natural gas sales increased to $258.0 million ($38.90 per boe) from $129.0 million ($40.46 per boe) in the same period of 2023. The increase is primarily due to the increased volumes added through the Pipestone Acquisition, partially offset by lower benchmark commodity prices.

The reduction in benchmark commodity prices also impacted royalties. For the three months ended March 31, 2024, royalties as a percentage of sales decreased to 10.2% from 16.5% in the same period of 2023.

Non-energy related production and operating expenses increased to $41.9 million ($6.32 per boe) for the three months ended March 31, 2024 from $14.3 million ($4.49 per boe) in the same quarter of 2023. The increase is primarily due to properties acquired through the Pipestone Acquisition.

Transportation and processing costs increased to $56.6 million ($8.53 per boe) for the three months ended March 31, 2024 from $19.2 million ($6.02 per boe) in the same quarter of 2023. The increase is primarily due to increased volumes added through the Pipestone Acquisition at a higher average unit cost than legacy Montney assets.

CAPITAL RESOURCES

Bank Credit Facility

Covenant-Based Revolving Credit Facility

As at March 31, 2024, the Company had a covenant-based revolving credit facility of $2.5 billion (December 31, 2023 - $2.3 billion) with a syndicate of Canadian, U.S. and international financial institutions (the "**Revolving Credit Facility**").

The Revolving Credit Facility has a maturity date of March 28, 2028, provided that the maturity date will be May 1, 2026 if the Senior Notes (as defined below) remain outstanding and have not been refinanced or legally defeased at such date. 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, Canadian Overnight Repo Rate Average ("**CORRA**") 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 March 31, 2024, the Company had letters of credit outstanding under the Revolving Credit Facility of $13.5 million (December 31, 2023 - $10.6 million).

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. 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 March 31, 2024 the cross-currency swap asset was $9.9 million (December 31, 2023 – $39.6 million liability) and total debt includes an unrealized loss of $8.8 million (December 31, 2023 – unrealized gain of $41.3 million) related to U.S. borrowings on the Revolving Credit Facility. Unrealized gains or losses on U.S. borrowings and offsetting unrealized gains or losses on cross-currency interest swap contracts are included in foreign exchange gains in the annual financial statements.

As at March 31, 2024, the Company had the following cross-currency interest rate swap contracts outstanding totaling.

Notional (US$)	Maturity Date	Contract Price
1,459.5 million	April 12, 2024	CAD/USD 1.3480

Financial Covenants

As at March 31, 2024, 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 5 of the interim 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 March 31, 2024, the Company was in compliance with such financial covenants, which are summarized in the following table.

As at	**March 31, 2024**
Total Debt to Adjusted EBITDA Ratio (≤ 4.00)(1)	**1.32**
Senior Debt to Adjusted EBITDA Ratio (≤ 3.50)(1)	**0.99**
Interest Coverage Ratio (≥ 3.50)(1)	**9.19**

(1) See "Specified Financial Measures" section of this MD&A.

Senior Notes

As at March 31, 2024, Strathcona had $677.0 million (December 31, 2023 - $662.2 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 March 31, 2024, the Company had a $100.0 million (December 31, 2023 - $100.0 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 March 31, 2024, the Company had letters of credit in the amount of $69.8 million (December 31, 2023 - $69.0 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 Revolving Credit Facility is summarized in the following table.

As at	**March 31, 2024**	December 31, 2023
Credit capacity	**2,500.0**	2,300.0
Revolving Credit Facility debt at period end exchange rate	**(2,006.3)**	(2,036.3)
Unrealized loss (gain) on U.S. borrowings	**8.8**	(41.3)
Letters of credit outstanding	**(13.5)**	(10.6)
Availability	**489.0**	211.8

The Company carries a working capital deficiency as part of its current capital structure. As at March 31, 2024, the working capital deficiency was $359.4 million (December 31, 2023 - $415.3 million). Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Company to remedy its working capital deficiency, meet its current and future obligations, to make scheduled 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 the Annual Information Form for the year ended December 31, 2023.

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 Revolving Credit Facility.

DECOMMISSIONING LIABILITY

At March 31, 2024, Strathcona's discounted decommissioning provision balance was $351.7 million (December 31, 2023 - $351.3 million) for future abandonment and reclamation of the Company's oil and natural gas properties. During the quarter the Company incurred $11.6 million of decommissioning expenditures to settle existing liabilities. This amount was offset by additions made as a result of new wells and facilities, accretion and changes in estimates.

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 March 31, 2024.

	Total	<1 year	1-3 years	4-5 years	> 5 years
Revolving Credit Facility(1)	**1,997.5**	—	1,997.5	—	—
Senior Notes(2)	**793.3**	46.5	746.8	—	—
Accounts payable and accrued liabilities	**771.5**	771.5	—	—	—
Risk management contract liability	**177.6**	26.4	151.2	—	—
Lease and other obligations(3)	**592.2**	88.8	158.0	111.5	233.9
Total	**4,332.1**	933.2	3,053.5	111.5	233.9

(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 ($677.0 million) and associated interest payments ($116.3 million) based on foreign exchange rate in effect on March 31, 2024.

(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 5 of the interim financial statements.

As at March 31, 2024, 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	**2,357.9**	277.9	543.8	471.0	1,065.2
Capital commitments	**194.6**	150.3	44.3	—	—
Other	**20.8**	6.6	11.6	2.6	—
Total	**2,573.3**	434.8	599.7	473.6	1,065.2

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. No preferred shares have been issued by the Company as at March 31, 2024 (December 31, 2023 – nil).

The following table summarizes the number of shares outstanding as at May 14, 2024:

Share Class	Shares Outstanding at May 14, 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 May 14, 2024.

SUMMARY OF QUARTERLY RESULTS

	2024	2023				2022		
($ millions, unless otherwise indicated)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Operating results (boe/d)								
Average production volumes	**185,122**	186,064	147,461	143,778	144,160	143,371	119,829	111,153
Average sales volumes	**182,862**	184,360	148,874	143,239	146,877	141,595	119,992	110,430
Financial Results								
Oil and natural gas sales	**1,298.8**	1,287.6	1,300.2	1,112.8	1,047.7	1,124.9	1,112.6	1,331.5
Net Income (loss)	**100.6**	263.7	(41.1)	274.1	90.5	62.2	606.3	349.7
Net income (loss) per share	**0.47**	1.23	(0.02)	0.13	0.04	0.03	0.28	0.16
Cash flow from operating activities	**408.8**	570.0	430.5	343.1	181.1	482.2	373.5	391.9
Operating Earnings(1)	**209.0**	202.1	289.9	201.4	101.9	169.4	284.3	405.0
Funds from Operations(1)	**455.6**	470.8	425.3	389.2	276.9	308.1	322.9	393.4
Free Cash Flow(1)	**157.9**	150.8	158.0	152.6	36.1	75.1	157.1	255.2
Field Operating Income(1)	**520.4**	527.4	549.6	460.8	315.9	395.1	432.4	538.2
Field Operating Netback ($/boe)(1)	**31.27**	31.09	40.13	35.35	23.82	30.33	39.16	53.55
Capital expenditures	**286.1**	307.8	260.2	231.7	228.7	228.5	157.5	136.8
Decommissioning expenditures	**11.6**	13.8	7.1	4.9	12.1	4.5	8.3	1.4
Total assets	**10,597.8**	10,496.9	9,588.9	9,451.2	9,289.5	9,164.5	9,416.3	6,091.0
Total debt	**2,642.5**	2,665.0	2,787.6	2,898.2	3,041.7	3,044.1	3,545.9	1,213.4
Total equity	**5,427.7**	5,327.1	4,526.4	4,567.5	4,292.7	4,202.2	4,088.9	3,594.6
Common shares outstanding, end of period	**214.2**	214.2	2,186.7	2,186.7	2,186.5	2,186.5	2,186.6	2,186.6

(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 Note 4 of the annual financial statements, volatility in the crude oil, condensate and natural gas benchmark prices, oil price differentials and changes in production. 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 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 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		
($ millions, unless otherwise indicated)	**March 31, 2024**	March 31, 2023	December 31, 2023
Oil and natural gas sales	**1,298.8**	1,047.7	1,287.6
Sales of purchased products	**2.0**	13.8	11.3
Purchased product	**(2.0)**	(14.8)	(10.3)
Blending costs	**(294.6)**	(285.2)	(284.8)
Oil and natural gas sales, net of blending	**1,004.2**	761.5	1,003.8
Royalties	**126.2**	113.1	134.9
Production and operating	**214.2**	204.6	205.8
Transportation and processing	**143.4**	127.9	135.7
Field Operating Income	**520.4**	315.9	527.4
Depletion, depreciation and amortization	**221.8**	163.1	227.5
Field Operating Earnings	**298.6**	152.8	299.9
Field Operating Netback ($/boe)	**31.27**	23.82	31.09
Field Operating Earnings Netback ($/boe)	**17.94**	11.48	17.68

"**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		
($ millions, unless otherwise indicated)	**March 31, 2024**	March 31, 2023	December 31, 2023
Income and comprehensive income	**100.6**	90.5	263.7
(Gain) loss on risk management contracts	**39.7**	(64.2)	(129.1)
Foreign exchange (gain) loss	**20.4**	(5.9)	(20.9)
Transaction related (recoveries) costs	**0.1**	1.2	(1.3)
Unrealized (gain) loss on Sable remediation fund	**0.1**	(0.2)	(0.3)
Deferred tax expense	**48.1**	80.5	90.0
Operating Earnings	**209.0**	101.9	202.1
Depletion, depreciation and amortization	**221.8**	163.1	227.5
Finance costs	**22.3**	17.8	21.6
Decommissioning government grant	**—**	(0.3)	—
Gain (loss) on risk management contracts - realized	**4.5**	(5.4)	19.5
Foreign exchange gain (loss) - realized	**(2.0)**	(0.2)	0.1
Funds from Operations	**455.6**	276.9	470.8
Capital expenditures	**(286.1)**	(228.7)	(306.2)
Decommissioning costs	**(11.6)**	(12.1)	(13.8)
Free Cash Flow	**157.9**	36.1	150.8

Previously, the Company adjusted income and comprehensive income for the impact of current income tax expense (recovery) to arrive at Operating Earnings. The adjustment of current income tax expense (recovery) has been removed from the calculation as costs associated with income tax are recurring in nature and management evaluates tax burdens / benefits in the analysis of Operating Earnings. The Company previously reported Operating Earnings of $55.0 million for the three months ended March 31, 2023 in the Management's Discussion and Analysis for the years ended December 31, 2023 and 2022. Operating Earnings are $101.9 million for the three months ended March 31, 2023 after removing the adjustment for current income tax expense (recovery). There is no impact to Operating Earnings in any other period presented within this MD&A.

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 Hardisty 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 March 31, 2024**
Revolving Credit Facility	**2,006.3**
Unrealized loss on SOFR loans	**(8.8)**
Senior Debt	**1,997.5**
Senior Notes	**677.0**
Total Debt	**2,674.5**

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 March 31, 2024**
Net income	**597.3**
Adjusted for	
Interest and finance costs	**277.3**
Unrealized gain on commodity contracts	**1.8**
Depletion, depreciation, amortization and impairment	**791.6**
Unrealized foreign exchange gain	**3.8**
Unrealized gain on Sable remediation fund	**0.1**
Income tax expense	**263.8**
ARO government grants	**—**
IFRS 16 adjustment	**(36.2)**
EBITDA from Pipestone assets	**122.9**
Non-recurring losses	**2.7**
Adjusted EBITDA	**2,025.1**

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 March 31, 2024**
Interest on debt	**197.5**
Other adjustments(1)	**22.8**
Interest Charges	**220.3**

(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 AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Strathcona is required to comply with National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("**NI 52-109**"). The certification of interim filings for the interim period ended March 31, 2024 requires that Strathcona disclose in the interim MD&A any changes in Strathcona's Internal controls over financial reporting ("**ICFR")** that occurred during the period that have materially affected, or are reasonably likely to materially affect, Strathcona's ICFR. Strathcona confirms that no such changes were made to its ICFR during the three months ended March 31, 2024.

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		
	March 31, 2024	March 31, 2023	December 31, 2023
Cold Lake Thermal segment			
Heavy crude oil (bbl/d)	**—**	—	—
Light and medium crude oil (bbl/d)	**—**	—	—
Total crude oil (bbl/d)	**—**	—	—
Bitumen (bbl/d)	**60,150**	51,097	59,845
NGLs (bbl/d)	**—**	—	—
Total liquids (bbl/d)	**60,150**	51,097	59,845
Conventional natural gas (mcf/d)	**—**	—	—
Total (boe/d)	**60,150**	51,097	59,845
Lloydminster Heavy Oil segment			
Heavy crude oil (bbl/d)	**51,835**	57,443	52,736
Light and medium crude oil (bbl/d)	**46**	43	40
Total crude oil (bbl/d)	**51,881**	57,486	52,776
Bitumen (bbl/d)	**—**	—	—
NGLs (bbl/d)	**2**	5	—
Total liquids (bbl/d)	**51,883**	57,491	52,776
Conventional natural gas (mcf/d)	**1,254**	895	1,260
Total (boe/d)	**52,092**	57,641	52,987
Montney segment			
Heavy crude oil (bbl/d)	**—**	—	—
Light and medium crude oil (bbl/d)	**505**	673	540
Total crude oil (bbl/d)	**505**	673	540
Bitumen (bbl/d)	**—**	—	—
NGLs (bbl/d)	**30,464**	15,848	30,509
Total liquids (bbl/d)	**30,969**	16,521	31,049
Conventional natural gas (mcf/d)	**251,466**	113,409	253,101
Total (boe/d)	**72,880**	35,422	73,232
Consolidated			
Heavy crude oil (bbl/d)	**51,835**	57,443	52,736
Light and medium crude oil (bbl/d)	**551**	716	580
Total crude oil (bbl/d)	**52,386**	58,159	53,316
Bitumen (bbl/d)	**60,150**	51,097	59,845
NGLs (bbl/d)	**30,466**	15,853	30,509
Total liquids (bbl/d)	**143,002**	125,109	143,670
Conventional natural gas (mcf/d)	**252,720**	114,304	254,361
Total (boe/d)	**185,122**	144,160	186,064

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; expectations in respect of the impact of the Trans Mountain Expansion Project on commodity prices; the Company’s use of hedging arrangements; the Company’s ability to meet current and future obligations, including making scheduled principal and interest payments, to fund planned capital expenditures 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.