STRATHCONA RESOURCES LTD

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEARS ENDED DECEMBER 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 March 4, 2025 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, 2024 and 2023 (the “**annual financial statements**”). The annual financial statements have been prepared in accordance with IFRS® Accounting Standards (the “**Accounting Standards**”) as issued by the International Accounting Standards Board, in Canadian dollars, except where indicated otherwise. The annual financial statements and MD&A of Strathcona have been prepared by management, reviewed by the Audit Committee of the Company's Board of Directors and were approved by the Company’s Board of Directors.

This MD&A contains forward looking information; see "Risk Factors" and “Forward-Looking Information” in this MD&A for further information. The following MD&A also contains financial measures that do not have a standardized meaning under the Accounting Standards; 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. Sales volumes differ from production volumes 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. 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 ("**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.

The significant differences in financial and operational results of the Company for the year ended December 31, 2024 compared to the year ended December 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.

RECENT DEVELOPMENTS

On January 31, 2025, certain limited partnerships comprising Waterous Energy Fund and its affiliates (collectively, “**WEF**”) completed a share pass-through transaction that resulted in a disposition of 24,010,576 Common Shares, representing approximately 11.2% of the issued and outstanding Common Shares. Following completion of this transaction, the ownership of the Common Shares held by WEF collectively decreased from approximately 90.8% to approximately 79.6%.

Effective March 4, 2025, US President Donald Trump confirmed Canadian energy products imported to the United States will be subject to a 10 per cent tariff. Of the approximately 115 Mbbls per day of bitumen and heavy oil Strathcona produces, approximately 85 Mbbls per day (“**Local Sales**”) is sold in Western Canada markets and approximately 30 Mbbls per day is sold in the United States Gulf Coast (“**USGC Sales**”). Tariffs are expected to impact Strathcona’s Local Sales to the extent they cause a widening in WTI-WCS Hardisty differentials, and in the fourth quarter of 2024 Strathcona hedged 45 Mbbls per day (approximately 53% of Local Sales) at a US$12.94 / bbl differential for full-year 2025. In the first quarter of 2025, Strathcona hedged approximately 21 Mbbls per day (approximately 70% of USGC sales) at a WTI-WCS Houston differential of US$3.52 per barrel between April and September 2025. It is not known how long tariffs will be in place, but Strathcona expects that their financial impact has been mitigated through much of 2025 because of these risk management contracts.

GUIDANCE

Strathcona's 2024 and 2025 annual guidance and actual results are outlined below:

	2024 Guidance[(1)]	**2024 Actual**	**2025 Guidance**
Production (Mboe/d)	**183**	**183**	**185 – 195**
Capital expenditures ($ millions)	**1,300**	**1,296**	**1,350**

(1) As announced on November 13, 2024 and disclosed in the Company's MD&A for the three and nine months ended September 30, 2024 and 2023.

PRODUCTION VOLUMES

	Three Months Ended			**Year Ended**	
	December 31, 2024	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Bitumen (bbl/d)	**59,732**	59,845	58,610	**59,516**	55,768
Heavy oil (bbl/d)	**50,997**	52,736	50,494	**51,107**	53,707
Condensate and light oil (bbl/d)	**20,763**	19,184	19,520	**19,922**	12,011
Total oil production (bbl/d)	**131,492**	131,765	128,624	**130,545**	121,486
Other NGLs (bbl/d)	**12,980**	11,906	11,680	**11,958**	9,021
Natural gas (mcf/d)	**256,386**	254,361	227,581	**243,456**	149,715
Total (boe/d)	**187,203**	186,064	178,235	**183,080**	155,459
% oil and condensate	**70 %**	71 %	72 %	**71 %**	78 %
% liquids	**77 %**	77 %	79 %	**78 %**	84 %

Production volumes increased 1% (or 1,139 boe per day) for the three months ended December 31, 2024 to an average of 187,203 boe per day compared to 186,064 boe per day for the same quarter of 2023. The increase is primarily attributable to new wells brought on stream in the Montney segment.

Production volumes increased 18% (or 27,621 boe per day) for the year ended December 31, 2024 to an average of 183,080 boe per day compared to 155,459 boe per day for the same period of 2023. The increase is primarily attributable to production from properties at Grande Prairie that were added through the Pipestone Acquisition completed in the fourth quarter of 2023 which contributed 30,545 boe per day in the year ended December 31, 2024 (December 31, 2023 - 7,651 boe per day). The remaining production increase is attributable to new wells drilled as part of the Company's capital program.

Production volumes increased 5% (or 8,968 boe per day) during the three months ended December 31, 2024 to an average of 187,203 boe per day compared to 178,235 boe per day for the three months ended September 30, 2024. This increase is primarily related to the Montney segment where production increased as a result of more favorable operating and gas pricing environments and from new well production in Kakwa. Production in the Montney segment for the three months ended September 30, 2024 was negatively impacted by planned and unplanned outages at third-party processing plants at Grande Prairie and deliberate production curtailments in Groundbirch in response to low gas prices. Production was restored at Groundbirch in the fourth quarter and third party processing facilities in Grande Prairie experienced better run times.

SALES VOLUMES

	Three Months Ended			Year Ended	
	December 31, 2024	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Bitumen (bbl/d)	**59,796**	60,027	58,422	**59,491**	55,766
Heavy oil (bbl/d)	**47,850**	50,849	50,839	**50,848**	54,169
Condensate and light oil (bbl/d)	**20,763**	19,184	19,520	**19,922**	12,011
Total oil production (bbl/d)	**128,409**	130,060	128,781	**130,261**	121,946
Other NGLs (bbl/d)	**12,980**	11,906	11,680	**11,958**	9,021
Natural gas (mcf/d)	**256,386**	254,361	227,581	**243,456**	149,715
Total (boe/d)	**184,120**	184,360	178,391	**182,794**	155,920

Sales volumes typically trend with production volumes, except in cases of an inventory build or draw. Strathcona carries inventory on rail cars in transit to the US Gulf Coast, on pipelines and in storage tanks. In the fourth quarter of 2024, the Company had a build up of heavy oil inventory related to volumes transported by rail due to weather conditions, which resulted in congestion at major rail hubs. Heavy oil inventory was sold shortly after year-end.

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
	December 31, 2024	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Benchmark Pricing					
US$/bbl unless otherwise indicated					
WTI[1]	**70.27**	78.32	75.10	**75.72**	77.62
WCS Hardisty[2]	**57.72**	56.43	61.55	**60.97**	58.92
WCS USGC[3]	**65.69**	71.59	68.51	**69.69**	69.73
WTI-WCS Hardisty differential	**(12.55)**	(21.89)	(13.55)	**(14.75)**	(18.70)
WTI-WCS USGC differential	**(4.58)**	(6.73)	(6.59)	**(6.03)**	(7.89)
NYMEX-AECO differential (US$/MMbtu)[4]	**(1.86)**	(1.13)	(1.62)	**(1.33)**	(0.79)
Condensate differential[5]	**0.39**	(2.09)	(3.90)	**(2.78)**	(1.03)
Average Exchange rate (C$/US$)	**1.3992**	1.3618	1.3636	**1.3700**	1.3495
CAD$/bbl unless otherwise indicated					
WTI[1]	**98.30**	106.72	102.43	**103.70**	104.78
WCS Hardisty[2]	**80.75**	76.85	83.96	**83.53**	79.51
WCS USGC[3]	**91.90**	97.49	93.45	**95.46**	94.10
AECO 5A (C$/gj)[6]	**1.40**	2.18	0.65	**1.38**	2.50
Condensate par at Edmonton	**98.85**	103.81	97.10	**99.92**	103.36
AESO weighted average pool price (C$/MWh)[7]	**53.10**	83.05	58.75	**64.54**	136.45
CORRA (%)[8]	**3.83**	5.03	4.54	**4.59**	4.75

(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").

WTI crude oil prices decreased 6% in the fourth quarter of 2024 compared to the third quarter of 2024 due to concerns about excess global crude supply, as the global market transitioned to a surplus in the fourth quarter of 2024. OPEC+ extended their 2.2 MMbpd production cut until April 2025 and announced plans to phase in their production increases more gradually than initially planned due to the supply surplus. The decrease in the WTI crude oil price due to excess supply was partially offset by speculation about policy changes under a new Trump administration.

The WTI-WCS Hardisty differential narrowed relative to WTI by 7% in the fourth quarter of 2024 compared to the third quarter of 2024. The continued strength in the differential was attributed to Western Canadian inventories remaining near the bottom of the five-year range, bolstered by surplus egress capacity as the Trans Mountain Pipeline Expansion came online in May 2024.

The WTI-WCS USGC differential narrowed relative to WTI by 31% in the fourth quarter of 2024 compared to the third quarter of 2024 due to low inventories in the USGC. Lower inventories were attributed to reduced imports of Mexican crude to the USGC due to production challenges and disruptions to the US Gulf of Mexico production from storms.

AECO 5A natural gas prices increased 113% in the fourth quarter of 2024 compared to the third quarter of 2024 due to colder than average weather in November and December resulting in storage draws. However, Canadian storage still remains significantly above the five-year average as production remains close to record high levels.

REVENUE AND REALIZED PRICES

Oil and Natural Gas Sales – Net of Blending

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Bitumen blend	**632.2**	591.8	616.8	**2,576.0**	2,280.8
Heavy oil, blended and raw	**409.9**	437.3	441.8	**1,795.7**	1,809.1
Condensate and light oil	**180.3**	172.3	169.9	**704.7**	431.0
Other natural gas liquids	**27.2**	26.9	24.0	**106.1**	79.4
Natural gas	**43.2**	59.3	20.0	**153.9**	148.0
Oil and natural gas sales	**1,292.8**	1,287.6	1,272.5	**5,336.4**	4,748.3
Gain (loss) purchased product	**(0.5)**	1.0	0.5	**—**	(0.2)
Bitumen – blending cost	**(232.6)**	(243.5)	(200.6)	**(929.9)**	(890.3)
Heavy oil – blending cost	**(35.1)**	(41.3)	(31.2)	**(151.6)**	(168.0)
Oil and natural gas sales, net of blending(1)	**1,024.6**	1,003.8	1,041.2	**4,254.9**	3,689.8

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

Oil and natural gas sales, net of blending, increased 2% (or $20.8 million) for the three months ended December 31, 2024 to $1,024.6 million compared to $1,003.8 million in the same quarter of 2023. This increase was primarily attributable to higher average realized oil prices, partially offset by lower average realized natural gas prices.

Oil and natural gas sales, net of blending, increased 15% (or $565.1 million) for the year ended December 31, 2024 to $4,254.9 million compared to $3,689.8 million for the same period in 2023. This increase was primarily attributable to increased sales volumes at Grande Prairie from properties acquired in the Pipestone Acquisition which was completed in the fourth quarter of 2023, higher average realized oil prices, partially offset by lower average realized natural gas prices.

Oil and natural gas sales, net of blending, decreased 2% (or $16.6 million) for the three months ended December 31, 2024 to $1,024.6 million compared to $1,041.2 million from the third quarter of 2024. This decrease is primarily due to lower average realized oil prices, partially offset by increased sales volumes and higher average realized natural gas prices.

Average Realized Prices

	Three Months Ended			Year Ended	
	December 31, 2024	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Bitumen blend ($/bbl)[1][2]	**72.62**	63.07	77.47	**75.61**	68.31
Heavy oil, blended and raw ($/bbl)[1][2]	**85.05**	84.23	87.88	**88.34**	83.00
Condensate and light oil ($/bbl)	**94.39**	97.62	94.61	**96.64**	98.30
Realized oil ($/bbl)	**80.81**	76.46	84.13	**83.79**	77.79
Other natural gas liquids ($/bbl)	**22.78**	24.56	22.33	**24.24**	24.12
Natural gas ($/mcf)	**1.83**	2.53	0.96	**1.73**	2.71
Combined ($/boe)	**60.49**	59.17	63.44	**63.60**	64.83

(1) Realized prices are calculated using oil and natural gas sales and sales of purchased product, net of blending and purchased product.

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

Combined realized price increased 2% (or $1.32 per boe) for the three months ended December 31, 2024 to $60.49 per boe compared to $59.17 per boe in the same quarter of 2023. The increase was primarily attributable to the strengthening of the WCS Hardisty benchmark as a result of narrowed differentials and reduced blending costs due to lower condensate benchmark pricing.

Combined realized price decreased 2% (or $1.23 per boe) for the year ended December 31, 2024 to $63.60 per boe compared to $64.83 per boe in the same period of 2023. The decrease was primarily attributable to lower natural gas price benchmarks which had a greater impact in the year ended December 31, 2024 as the Company's sales mix was more heavily weighted to natural gas due to the acquisition of Pipestone, partially offset by increased WCS Hardisty and USGC benchmark pricing.

Combined realized price decreased 5% (or $2.95 per boe) for the three months ended December 31, 2024 to $60.49 per boe compared to $63.44 per boe for the three months ended September 30, 2024. The decrease was due to a decrease in the WCS Hardisty and USGC benchmark prices combined with higher per barrel blend costs as colder weather necessitated more diluent in order to meet pipeline specifications.

ROYALTIES

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Crown royalties[1]	**188.2**	96.3	97.5	**528.3**	405.1
Freehold royalties[1]	**6.8**	14.0	7.5	**30.4**	56.7
Gross overriding royalties[1]	**10.5**	17.2	22.2	**81.5**	73.9
Other royalties	**3.0**	7.4	6.8	**22.5**	21.2
Royalties	**208.5**	134.9	134.0	**662.7**	556.9
Effective royalty rate (%)[1]	**20.3 %**	13.4 %	12.9 %	**15.6 %**	15.1 %

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

For the three months ended and year ended December 31, 2024, the effective royalty rate was 20.3% and 15.6%, respectively, compared to 13.4% and 15.1% for the same periods in 2023. For the three months ended December 31, 2024, the effective royalty rate increased compared to 12.9% in the third quarter of 2024. These increases are primarily attributable to the timing of eligibility of capital deductions relating to projects at thermal properties.

PRODUCTION AND OPERATING EXPENSES

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Production and operating – Energy[(1)]	**58.7**	72.5	45.7	**248.1**	322.3
Production and operating – Non-energy[(1)]	**138.5**	133.3	140.2	**563.6**	474.0
Production and operating expenses	**197.2**	205.8	185.9	**811.7**	796.3
Production and operating – Energy ($/boe)[(1)]	**3.46**	4.27	2.78	**3.71**	5.66
Production and operating – Non-energy ($/boe)[(1)]	**8.18**	7.86	8.54	**8.42**	8.33
Production and operating expenses ($/boe)	**11.64**	12.13	11.32	**12.13**	13.99

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

Production and operating expenses decreased 4% (or $8.6 million) for the three months ended December 31, 2024 to $197.2 million ($11.64 per boe) from $205.8 million ($12.13 per boe) in the same period of 2023. Energy costs decreased by $13.8 million ($0.81 per boe) primarily due to lower natural gas and power benchmark prices. Non-energy costs increased by $5.2 million ($0.32 per boe) primarily due to increased chemical costs as a result of sulphur recovery units installed at the Company's Cold Lake segment in the first quarter of 2024.

Production and operating expenses increased 2% (or $15.4 million) for the year ended December 31, 2024 to $811.7 million ($12.13 per boe), from $796.3 million ($13.99 per boe) in the same period of 2023. Energy costs decreased by $74.2 million ($1.95 per boe) primarily due to lower natural gas and power benchmark prices and savings realized on carbon taxes as a result of carbon credit purchases, partially offset by increased carbon taxes as certain thermal properties in Saskatchewan entered their first year of compliance. Non-energy costs increased by $89.6 million ($0.09 per boe) primarily due to $62.7 million in incremental costs relating to properties acquired in the Pipestone Acquisition and increased chemical costs at Cold Lake as a result of sulphur recovery units installed in the first quarter of 2024.

Energy production and operating costs increased 28% (or $13.0 million) for the three months ended December 31, 2024 to $58.7 million ($3.46 per boe), compared to $45.7 million ($2.78 per boe) for the three months ended September 30, 2024. The increase is primarily due to higher natural gas prices and carbon taxes impacting the Cold Lake segment in the fourth quarter of 2024. Non-energy production and operating costs decreased to $138.5 million ($8.18 per boe) for the three months ended December 31, 2024 compared to $140.2 million ($8.54 per boe) for the three months ended September 30, 2024. The decrease was primarily due to a decrease in labour related costs as well as surface maintenance costs.

TRANSPORTATION AND PROCESSING EXPENSES

($ millions, unless otherwise indicated)	Three Months Ended			Year Ended	
	December 31, 2024	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Transportation expenses[1]	**117.8**	109.7	116.1	**471.9**	435.9
Processing expenses[1]	**26.4**	26.0	24.1	**105.1**	47.0
Transportation and processing expenses	**144.2**	135.7	140.2	**577.0**	482.9
$ per boe	**8.51**	8.00	8.54	**8.62**	8.49

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

Transportation and processing expenses increased 6% (or $8.5 million) for the three months ended December 31, 2024 to $144.2 million (8.51 per boe) compared to $135.7 million ($8.00 per boe) in the same period of 2023. The increase is primarily attributable to increased bitumen transportation costs, as well as the Company benefiting from certain cost savings due to the utilization of make-up rights at Cold Lake in the comparable period.

Transportation and processing expenses increased 19% (or $94.1 million) for the year ended December 31, 2024 to $577.0 million ($8.62 per boe) compared to $482.9 million ($8.49 per boe) in the same period of 2023. These increases are primarily the result of increased sales volumes from the properties acquired in the Pipestone Acquisition, increased bitumen transportation costs due to cost savings in 2023 that resulted from the utilization of make-up rights, partially offset by decreased heavy oil transportation due to lower volumes sold on rail. The incremental transportation and processing costs associated with the properties acquired in the Pipestone Acquisition for the three months and year ended December 31, 2024 were $30.7 million and $125.0 million, respectively.

Transportation and processing expenses increased 3% (or $4.0 million) for the three months ended December 31, 2024 to $144.2 million ($8.51 per boe) from $140.2 million ($8.54 per boe) in the three months ended September 30, 2024. The increase was primarily attributable to higher natural gas transportation and processing charges resulting from increased production in the Montney segment, partially offset by reduced rail transportation costs as lower volumes were transported by rail in the fourth quarter of 2024.

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

($ millions, unless otherwise indicated)	Three Months Ended			Year Ended	
	December 31, 2024	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Depletion expense[1]	**181.9**	214.8	212.5	**819.3**	699.6
Depreciation and amortization expense[1]	**14.4**	12.7	13.8	**54.2**	33.3
DD&A	**196.3**	227.5	226.3	**873.5**	732.9
$ per boe	**11.59**	13.41	13.79	**13.06**	12.88

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

DD&A expense decreased 14% (or $31.2 million) for the three months ended December 31, 2024 to $196.3 million ($11.59 per boe) compared to $227.5 million ($13.41 per boe) for the same period of 2023. This decrease was primarily attributable to updated depletion rate estimates in the Montney segment.

DD&A expense increased 19% (or $140.6 million) for the year ended December 31, 2024 to $873.5 million ($13.06 per boe), compared to $732.9 million ($12.88 per boe) for the same period of 2023. This increase was primarily due to an increase in production volumes as a result of the Pipestone Acquisition.

DD&A expense decreased 13.3% (or $30.0 million) during the three months ended December 31, 2024 to $196.3 million ($11.59 per boe) compared to $226.3 million ($13.79 per boe) for the three months ended September 30, 2024. This decrease was primarily attributable to updated depletion rate estimates in the Montney segment.

GENERAL AND ADMINISTRATION EXPENSES ("G&A")

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
G&A expenses	**28.4**	24.5	25.5	**101.1**	91.9
$ per boe	**1.68**	1.44	1.55	**1.51**	1.61

For the three months and year ended December 31, 2024, G&A expenses increased 16% (or $3.9 million) and 10% (or $9.2 million) to $28.4 million ($1.68 per boe) and $101.1 million ($1.51 per boe), respectively, compared to $24.5 million ($1.44 per boe) and $91.9 million ($1.61 per boe) for the same periods in 2023. These increases were primarily the result of increased personnel and information technology costs.

G&A expenses increased 11% (or $2.9 million) during the three months ended December 31, 2024, $28.4 million ($1.68 per boe) compared to $25.5 million ($1.55 per boe) for the three months ended September 30, 2024. The increase was primarily due to increased personnel costs.

INTEREST

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Interest expense	**39.0**	51.6	42.1	**170.2**	206.2
Weighted average interest rate (%)	**5.8 %**	6.7 %	6.1 %	**6.1 %**	6.5 %

For the three months and year ended December 31, 2024, interest expense decreased 24% (or $12.6 million) and 17% (or $36.0 million) to $39.0 million and $170.2 million, respectively, compared to $51.6 million and $206.2 million in the same periods of 2023. Interest expense decreased 7% (or $3.1 million) for the three months ended December 31, 2024 to $39.0 million compared to $42.1 million for the three months ended September 30, 2024. These decreases were primarily the result of lower debt levels and lower interest rates.

During the year ended December 31, 2024, the Company recorded $47.1 million in interest expense on the Senior Notes (as defined in the "Capital Resources" section of this MD&A) (December 31, 2023 – $46.4 million), and $146.1 million in interest expense on the Credit Facilities (as defined in the "Capital Resources" section of this MD&A) (December 31, 2023 - $178.4 million), and a realized gain of $23.0 million on interest rate swaps (December 31, 2023 - $18.6 million).

The impact of changes in 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 **December 31, 2024**	 December 31, 2023	 September 30, 2024	Year Ended **December 31, 2024**	 December 31, 2023
Accretion of lease obligations	**5.9**	5.9	5.9	**24.1**	14.5
Accretion of decommissioning provision	**7.1**	7.1	7.1	**28.3**	28.7
Amortization of debt issuance costs	**5.1**	3.5	6.3	**20.5**	13.0
Accretion of other obligations	**2.9**	5.1	2.6	**15.4**	19.1
Finance costs	**21.0**	21.6	21.9	**88.3**	75.3

Finance costs for the three months ended December 31, 2024 remained consistent at $21.0 million compared to $21.6 million for the same period of 2023.

Finance costs increased 17% (or $13.0 million) to $88.3 million for the year ended December 31, 2024 compared to $75.3 million in the same period of 2023. This increase was primarily 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 borrowing capacity under the Revolving Credit Facility (as defined in the "Capital Resources" section of this MD&A). On March 28, 2024 the Company increased the Revolving Credit Facility to $2.5 billion from $2.3 billion and extended the maturity date to March 28, 2028; provided that the maturity date will be May 1, 2026 if the Senior Notes (as defined in the “Capital Resources” section of this MD&A) remain outstanding and have not been refinanced or legally defeased at such date.

Finance costs remained consistent for the three months ended December 31, 2024 at $21.0 million compared to $21.9 million for the three months ended September 30, 2024.

TAX POOLS

As at December 31, 2024, the Company had approximately $5,595.4 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	**December 31, 2024**	December 31, 2023
Canadian oil and gas property expenditures(1)	10%	**838.5**	893.4
Canadian development expenditures(1)	30%	**1,279.7**	1,168.8
Canadian exploration expenditures(1)	100%	**18.3**	34.1
Undepreciated capital costs(2)	4% - 55%	**1,502.6**	1,371.0
Non-capital losses	100%	**1,707.6**	2,173.1
Other(1)(3)		**248.7**	440.7
Total tax pools		**5,595.4**	6,081.1

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

(2) As at December 31, 2024, approximately 92% (December 31, 2023 – 96%) of costs in this pool have an annual deduction rate of 25%.

(3) "Other" tax pools are comprised of federal and provincial scientific research and experimental development expenditure pools and credits and financing costs.

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
Jan 1, 2025 - Dec 31, 2025	Swap	WCS	USD	45,000	bbl/d	$(12.94)
Apr 1, 2025 - Jun 30, 2025	Swap	ARV	USD	18,500	bbl/d	$(3.59)
Jul 1, 2025 - Sep 30, 2025	Swap	ARV	USD	23,500	bbl/d	$(3.46)
Dec 1, 2024 - Mar 31, 2025	Collar	AECO	CAD	30,000	GJ/d	$2.50/$3.51

(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.

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.

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

Term	Contract	Bought Put - USD per Month	Bought Put Price - CAD/USD	Sold Call - USD per Month	Sold Call - CAD/USD
Feb 1, 2025 - Jun 30, 2026	Collar	100.0 million	1.2500	130.0 million	1.4500

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	Sold Put Option	500.0 million	1.3775

Interest Rate Risk

The Company is exposed to movements in floating interest rates on the Credit Facilities. The Company is not exposed to interest rate risk on the Senior Notes or other liabilities 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	Oct 1, 2024 - Apr 30, 2030	Swap[1]	CORRA	2.9453%

(1) The swap contracts have a term to April 30, 2030. The counterparties have an option to terminate the swap effective May 1, 2028, which is exercisable on April 28, 2028.

For a listing of the Company’s commodity contracts, foreign exchange and interest rate contracts outstanding as at December 31, 2024 refer to Note 14 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, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Loss (gain) on risk management contracts - realized[1]	**5.4**	(19.5)	94.7	**107.0**	42.4
(Gain) loss on risk management contracts - unrealized	**(15.6)**	(109.6)	(78.1)	**(63.0)**	(112.0)
Total loss (gain) on risk management contracts	**(10.2)**	(129.1)	16.6	**44.0**	(69.6)
Realized loss (gain) on risk management contracts per boe	**0.32**	(1.15)	5.77	**1.60**	(0.74)

(1) During the year ended December 31, 2024, the Company settled premiums associated with expired bought calls for non-cash consideration of $112.4 million (see "Other Obligations" section in this MD&A).

Strathcona realized a loss on risk management contracts of $5.4 million for the three months ended December 31, 2024, compared to a gain of $19.5 million for the same period in 2023. The realized loss in the three months ended December 31, 2024 was primarily due to cash settlement of the loss position on foreign exchange contracts resulting from the weakened Canadian dollar and losses on commodity contracts.

Strathcona realized a loss on risk management contracts of $107.0 million for the year ended December 31, 2024 compared to a loss of $42.4 million in the same period of 2023. The realized loss for the year end December 31, 2024 was primarily due to the settlement of premiums associated with expired bought calls for non-cash consideration of $112.4 million in the third quarter of 2024, partially offset by cash settlement of gain positions on WTI crude oil contracts.

As at December 31, 2024, the mark-to-market value of risk management contracts was a net liability of $40.7 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 14 to the annual financial statements.

CAPITAL EXPENDITURES

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

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Cold Lake	**138.3**	69.7	96.0	**371.7**	306.0
Lloydminster	**138.3**	96.2	113.3	**445.2**	360.5
Montney	**112.9**	139.3	108.4	**470.3**	351.0
Corporate	**3.0**	2.6	1.9	**9.0**	10.9
Capital expenditures	**392.5**	307.8	319.6	**1,296.2**	1,028.4

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

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Drilling, completion and equipping	**170.6**	177.3	175.5	**674.6**	592.5
Facilities and pipelines	**172.5**	96.5	113.1	**456.0**	311.0
Recompletion, workovers and polymer powder	**34.3**	19.2	19.4	**106.9**	70.1
Capitalized G&A and other expenditures	**15.1**	14.8	11.6	**58.7**	54.8
Capital expenditures	**392.5**	307.8	319.6	**1,296.2**	1,028.4

For the three months ended December 31, 2024, drilling, completion and equipping activities accounted for 43% of capital expenditures as the Company drilled 81 new wells during the fourth quarter of 2024; 22 in Cold Lake, 49 in Lloydminster and 10 in Montney. For the year ended December 31, 2024, drilling, completion and equipping activities accounted for 52% of capital expenditures as the Company drilled 268 new wells during the year; 60 at Cold Lake, 177 in Lloydminster and 31 in Montney. For the year ended December 31, 2024 facilities and pipeline expenditures accounted for 35% of capital expenditures and relate primarily to Lindbergh debottlenecking, Meota West 2 OTSG addition, Meota Central brownfield development and the Kakwa 6-8 facility expansion.

For the three months and year ended December 31, 2024, capital expenditures increased 28% (or $84.7 million) and 26% (or $267.8 million) to $392.5 million and $1,296.2 million, respectively, compared to $307.8 million and $1,028.4 million for the same periods of 2023. Capital expenditures increased 23% (or $72.9 million) for the three months ended December 31, 2024 to $392.5 million compared to $319.6 million for the three months ended September 30, 2024. Capital expenditures will vary year over year depending on annual capital expenditure guidance. Full year 2024 capital expenditures were in line with annual guidance of $1.3 billion.

FOREIGN EXCHANGE

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2024**	 December 31, 2023	 September 30, 2024	Year Ended **December 31, 2024**	 December 31, 2023
Realized (gain) loss	**(3.6)**	(0.1)	2.6	**0.5**	(1.4)
Unrealized loss (gain) - Senior Notes	**42.9**	(16.8)	(7.7)	**57.0**	(15.6)
Unrealized loss (gain) - Credit Facilities	**39.3**	(38.0)	1.0	**69.8**	(47.2)
Unrealized (gain) loss - cross-currency swaps	**(38.7)**	36.7	(0.9)	**(68.2)**	43.9
Unrealized loss (gain) - other	**7.8**	(2.7)	(1.8)	**9.1**	(1.8)
Foreign exchange loss (Gain)	**47.7**	(20.9)	(6.8)	**68.2**	(22.1)

Foreign exchange for the three months ended December 31, 2024 resulted in a loss of $47.7 million compared to a gain of $20.9 million and a gain of $6.8 million for the three months ended December 31, 2023 and September 30, 2024, respectively. For the year ended December 31, 2024, foreign exchange resulted in a loss of $68.2 million compared to a gain of $22.1 million in the prior year. 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

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

- Cold Lake, which includes the development and production of bitumen in the Cold Lake region of Northern Alberta;
- Lloydminster, which includes the development and production of heavy oil through enhanced oil recovery and thermal steam-assisted gravity drainage ("**SAGD**") methods in Southeast Alberta and Southwest Saskatchewan; and
- Montney, which includes the development and production of liquids rich natural gas produced from the Montney region in Northwest Alberta and Northeast British Columbia.

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

The following tables present the financial performance by reportable segment and include a measure of segment profit or loss regularly reviewed by management for the noted periods ended December 31, 2024 and 2023. Certain comparative information related to sale of purchased product and purchased product has been allocated by segment to conform with current period presentation. Field operating earnings is the metric used to evaluate segment profit or loss which includes depletion, depreciation and amortization. Field operating income, which excludes depletion, depreciation and amortization, was used to evaluate segment profit or loss in the comparative period.

For the Three Months Ended ($ millions, unless otherwise indicated)	Cold Lake Segment			Lloydminster Segment			Montney Segment			Corporate			Consolidated		
	Dec 31, 2024	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024
Production volumes															
Bitumen (bbl/d)	**59,732**	59,845	58,610	**—**	—	—	**—**	—	—	**—**	—	—	**59,732**	59,845	58,610
Heavy oil (bbl/d)	**—**	—	—	**50,997**	52,736	50,494	**—**	—	—	**—**	—	—	**50,997**	52,736	50,494
Condensate and light oil (bbl/d)	**—**	—	—	**64**	40	32	**20,699**	19,144	19,488	**—**	—	—	**20,763**	19,184	19,520
Other NGLs (bbl/d)	**—**	—	—	**4**	1	—	**12,976**	11,905	11,680	**—**	—	—	**12,980**	11,906	11,680
Natural gas (mcf/d)	**—**	—	—	**1,295**	1,260	1,150	**255,091**	253,101	226,431	**—**	—	—	**256,386**	254,361	227,581
Production volumes (boe/d)	**59,732**	59,845	58,610	**51,281**	52,987	50,718	**76,190**	73,232	68,907	**—**	—	—	**187,203**	186,064	178,235
Sales volumes (boe/d)	**59,796**	60,027	58,422	**48,134**	51,100	51,062	**76,190**	73,232	68,907	**—**		—	**184,120**	184,360	178,391
Segment revenues															
Oil and natural gas sales	**632.1**	592.0	616.9	**409.9**	437.8	442.3	**250.4**	257.8	213.4	**0.4**	—	(0.1)	**1,292.8**	1,287.6	1,272.5
Sales of purchased products	**—**	8.1	11.5	**5.6**	3.2	20.4	**—**	—	—	**10.0**	—	12.5	**15.6**	11.3	44.4
Blending costs	**(232.6)**	(243.5)	(200.6)	**(35.1)**	(41.3)	(31.2)	**—**	—	—	**—**	—	—	**(267.7)**	(284.8)	(231.8)
Purchased product	**—**	(7.3)	(11.4)	**(5.7)**	(3.0)	(20.1)	**—**	—	—	**(10.4)**	—	(12.4)	**(16.1)**	(10.3)	(43.9)
Oil and natural gas sales, net of blending[(1)]	**399.5**	349.3	416.4	**374.7**	396.7	411.4	**250.4**	257.8	213.4	**—**	—	—	**1,024.6**	1,003.8	1,041.2
Segment expenses															
Royalties	**132.9**	73.8	74.4	**52.1**	41.7	39.5	**23.5**	19.4	20.1	**—**	—	—	**208.5**	134.9	134.0
Production and operating – Energy[(1)]	**29.9**	39.6	19.4	**26.7**	31.4	24.7	**2.1**	1.5	1.6	**—**	—	—	**58.7**	72.5	45.7
Production and operating – Non-energy[(1)]	**49.5**	44.9	46.8	**44.9**	50.6	54.5	**44.1**	37.8	38.9	**—**	—	—	**138.5**	133.3	140.2
Transportation and processing	**22.3**	18.7	21.7	**66.3**	65.4	68.5	**55.6**	51.6	50.0	**—**	—	—	**144.2**	135.7	140.2
Field Operating Income[(1)]	**164.9**	172.3	254.1	**184.7**	207.6	224.2	**125.1**	147.5	102.8	**—**	—	—	**474.7**	527.4	581.1
Depletion, depreciation and amortization	**39.7**	42.9	42.2	**97.3**	103.5	103.7	**54.6**	76.7	76.0	**4.7**	4.4	4.4	**196.3**	227.5	226.3
Field Operating Earnings[(1)]	**125.2**	129.4	211.9	**87.4**	104.1	120.5	**70.5**	70.8	26.8	**(4.7)**	(4.4)	(4.4)	**278.4**	299.9	354.8
General and administrative	**—**	—	—	**—**	—	—	**—**	—	—	**28.4**	24.5	25.5	**28.4**	24.5	25.5
Other (income) loss	**—**	—	—	**—**	—	—	**—**	—	—	**—**	0.1	(0.1)	**—**	0.1	(0.1)
Interest expense	**—**	—	—	**—**	—	—	**—**	—	—	**39.0**	51.6	42.1	**39.0**	51.6	42.1
Finance costs	**—**	—	—	**—**	—	—	**—**	—	—	**21.0**	21.6	21.9	**21.0**	21.6	21.9
Operating Earnings[(1)]													**190.0**	202.1	265.4
Loss (gain) on risk management contracts - realized	**—**	—	—	**—**	—	—	**—**	—	—	**5.4**	(19.5)	94.7	**5.4**	(19.5)	94.7
(Gain) loss on risk management contracts - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**(15.6)**	(109.6)	(78.1)	**(15.6)**	(109.6)	(78.1)
Foreign exchange (gain) loss - realized	**—**	—	—	**—**	—	—	**—**	—	—	**(3.6)**	(0.1)	2.6	**(3.6)**	(0.1)	2.6
Foreign exchange loss (gain) - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**51.3**	(20.8)	(9.4)	**51.3**	(20.8)	(9.4)
Transaction related costs	**—**	—	—	**—**	—	—	**—**	—	—	**0.3**	(1.3)	0.3	**0.3**	(1.3)	0.3
Unrealized (gain) loss on Sable remediation fund	**—**	—	—	**—**	—	—	**—**	—	—	**—**	(0.3)	(0.2)	**—**	(0.3)	(0.2)
Loss on settlement of other obligations	**—**	—	—	**—**	—	—	**—**	—	—	**—**	—	4.4	**—**	—	4.4
Deferred tax expense	**—**	—	—	**—**	—	—	**—**	—	—	**64.3**	90.0	63.1	**64.3**	90.0	63.1
Income and comprehensive income													**87.9**	263.7	188.0

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

For the Three Months Ended ($/boe)	Cold Lake Segment			Lloydminster Segment			Montney Segment			Corporate			Consolidated		
	Dec 31, 2024	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024
Segment revenues															
Oil and natural gas sales	**80.88**	76.00	83.80	**87.17**	86.86	89.40	**35.72**	38.26	33.66	**0.02**	—	(0.01)	**66.21**	65.82	68.24
Sales of purchased products	**—**	1.47	2.14	**1.26**	0.68	4.34	**—**	—	—	**0.59**	—	0.76	**0.92**	0.67	2.71
Blending costs	**(8.26)**	(12.90)	(6.35)	**(2.53)**	(2.52)	(1.88)	**—**	—	—	**—**	—	—	**(5.69)**	(6.71)	(4.84)
Purchased product	**—**	(1.32)	(2.12)	**(1.29)**	(0.64)	(4.28)	**—**	—	—	**(0.61)**	—	(0.76)	**(0.95)**	(0.61)	(2.67)
Oil and natural gas sales, net of blending(1)	**72.62**	63.25	77.47	**84.61**	84.38	87.58	**35.72**	38.26	33.66	**—**	—	(0.01)	**60.49**	59.17	63.44
Segment expenses															
Royalties	**24.16**	13.36	13.84	**11.77**	8.87	8.41	**3.35**	2.88	3.17	**—**	—	—	**12.31**	7.95	8.16
Production and operating – Energy(1)	**5.44**	7.17	3.61	**6.03**	6.68	5.26	**0.30**	0.22	0.25	**—**	—	—	**3.46**	4.27	2.78
Production and operating – Non-energy(1)	**9.00**	8.13	8.71	**10.14**	10.76	11.60	**6.29**	5.61	6.14	**—**	—	—	**8.18**	7.86	8.54
Transportation and processing	**4.05**	3.39	4.04	**14.97**	13.91	14.58	**7.93**	7.66	7.89	**—**	—	—	**8.51**	8.00	8.54
Field Operating Netback(1)	**29.97**	31.20	47.27	**41.70**	44.16	47.73	**17.85**	21.89	16.21	**—**	—	(0.01)	**28.03**	31.09	35.42
Depletion, depreciation and amortization	**7.22**	7.77	7.85	**21.97**	22.02	22.07	**7.79**	11.38	11.99	**0.28**	0.26	0.27	**11.59**	13.41	13.79
Field Operating Earnings Netback(1)	**22.75**	23.43	39.42	**19.73**	22.15	25.66	**10.06**	10.51	4.22	**(0.28)**	(0.26)	(0.28)	**16.44**	17.68	21.63
General and administrative	**—**	—	—	**—**	—	—	**—**	—	—	**1.68**	1.44	1.55	**1.68**	1.44	1.55
Other (income) expense	**—**	—	—	**—**	—	—	**—**	—	—	**—**	0.01	(0.01)	**—**	0.01	(0.01)
Interest expense	**—**	—	—	**—**	—	—	**—**	—	—	**2.30**	3.04	2.57	**2.30**	3.04	2.57
Finance costs	**—**	—	—	**—**	—	—	**—**	—	—	**1.24**	1.27	1.33	**1.24**	1.27	1.33
Operating Earnings(1)													**11.22**	11.92	16.19
Effective royalty rate (%)(1)	**33.3**	21.1	17.9	**13.9**	10.5	9.6	**9.4**	7.5	9.4				**20.3**	13.4	12.9

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

For the Year Ended ($ millions, unless otherwise indicated)	Cold Lake Segment		Lloydminster Segment		Montney Segment		Corporate		Consolidated	
	December 31, 2024	December 31, 2023	December 31, 2024	December 31, 2023	December 31, 2024	December 31, 2023	December 31, 2024	December 31, 2023	December 31, 2024	December 31, 2023
Production volumes										
Bitumen (bbl/d)	59,516	55,768	—	—	—	—	—	—	59,516	55,768
Heavy oil (bbl/d)	—	—	51,107	53,707	—	—	—	—	51,107	53,707
Condensate and light oil (bbl/d)	—	—	42	42	19,880	11,969	—	—	19,922	12,011
Other NGLs (bbl/d)	—	—	2	1	11,956	9,020	—	—	11,958	9,021
Natural gas (mcf/d)	—	—	1,232	1,080	242,224	148,635	—	—	243,456	149,715
Production volumes (boe/d)	59,516	55,768	51,357	53,930	72,207	45,761	—	—	183,080	155,459
Sales volumes (boe/d)	59,491	55,766	51,097	54,393	72,206	45,761	—	—	182,794	155,920
Segment revenues										
Oil and natural gas sales	2,576.0	2,279.2	1,797.1	1,812.5	963.0	655.5	0.3	1.1	5,336.4	4,748.3
Sales of purchased product	18.3	20.1	26.0	12.2	—	—	30.7	14.0	75.0	46.3
Blending costs	(929.9)	(888.1)	(151.6)	(170.2)	—	—	—	—	(1,081.5)	(1,058.3)
Purchased product	(18.2)	(19.5)	(25.8)	(11.9)	—	—	(31.0)	(15.1)	(75.0)	(46.5)
Oil and natural gas sales, net of blending(1)	1,646.2	1,391.7	1,645.7	1,642.6	963.0	655.5	—	—	4,254.9	3,689.8
Segment expenses										
Royalties	385.3	323.3	181.7	175.1	95.7	58.5	—	—	662.7	556.9
Production and operating – Energy(1)	127.9	198.4	112.8	120.5	7.4	3.4	—	—	248.1	322.3
Production and operating – Non-energy(1)	196.0	173.9	203.7	216.3	163.9	83.8	—	—	563.6	474.0
Transportation and processing	87.7	80.4	276.2	293.7	213.1	108.8	—	—	577.0	482.9
Field Operating Income(1)	849.3	615.7	871.3	837.0	482.9	401.0	—	—	2,203.5	1,853.7
Depletion, depreciation and amortization	167.1	148.9	411.1	423.2	278.5	145.9	16.8	14.9	873.5	732.9
Field Operating Earnings(1)	682.2	466.8	460.2	413.8	204.4	255.1	(16.8)	(14.9)	1,330.0	1,120.8
General and administrative	—	—	—	—	—	—	101.1	91.9	101.1	91.9
Other income	—	—	—	—	—	—	(0.1)	(1.0)	(0.1)	(1.0)
Interest expense	—	—	—	—	—	—	170.2	206.2	170.2	206.2
Finance costs	—	—	—	—	—	—	88.3	75.3	88.3	75.3
Current income tax (recovery)	—	—	—	—	—	—	—	(46.9)	—	(46.9)
Operating Earnings(1)									970.5	795.3
Loss (gain) on risk management contracts - realized	—	—	—	—	—	—	107.0	42.4	107.0	42.4
(Gain) loss on risk management contracts - unrealized	—	—	—	—	—	—	(63.0)	(112.0)	(63.0)	(112.0)
Foreign exchange loss (gain) - realized	—	—	—	—	—	—	0.5	(1.4)	0.5	(1.4)
Foreign exchange loss (gain) - unrealized	—	—	—	—	—	—	67.7	(20.7)	67.7	(20.7)
Transaction related costs	—	—	—	—	—	—	1.0	3.8	1.0	3.8
Unrealized (gain) loss on Sable remediation fund	—	—	—	—	—	—	(0.1)	(0.2)	(0.1)	(0.2)
Loss on settlement of other obligations	—	—	—	—	—	—	4.4	—	4.4	—
Deferred tax expense	—	—	—	—	—	—	249.3	296.2	249.3	296.2
Income and comprehensive income									603.7	587.2

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

For the Year Ended ($/boe)	Cold Lake Segment December 31, 2024	December 31, 2023	Lloydminster Segment December 31, 2024	December 31, 2023	Montney Segment December 31, 2024	December 31, 2023	Corporate December 31, 2024	December 31, 2023	Consolidated December 31, 2024	December 31, 2023
Segment revenues										
Oil and natural gas sales	**83.42**	79.53	**90.35**	85.58	**36.44**	39.24	**—**	0.01	**69.13**	71.36
Sales of purchased products	**0.84**	0.99	**1.39**	0.61	**—**	—	**0.46**	0.26	**1.12**	0.81
Blending costs	**(7.82)**	(11.19)	**(2.36)**	(2.85)	**—**	—	**—**	—	**(5.53)**	(6.52)
Purchased product	**(0.84)**	(0.96)	**(1.38)**	(0.60)	**—**	—	**(0.46)**	(0.27)	**(1.12)**	(0.82)
Oil and natural gas sales, net of blending(1)	**75.60**	68.37	**88.00**	82.74	**36.44**	39.24	**—**	—	**63.60**	64.83
Segment expenses										
Royalties	**17.69**	15.88	**9.72**	8.82	**3.62**	3.50	**—**	—	**9.91**	9.78
Production and operating – Energy(1)	**5.87**	9.75	**6.03**	6.07	**0.28**	0.20	**—**	—	**3.71**	5.66
Production and operating – Non-energy(1)	**9.00**	8.54	**10.89**	10.90	**6.20**	5.02	**—**	—	**8.42**	8.33
Transportation and processing	**4.03**	3.95	**14.77**	14.79	**8.06**	6.51	**—**	—	**8.62**	8.49
Field Operating Netback(1)	**39.01**	30.25	**46.59**	42.16	**18.28**	24.01	**—**	—	**32.94**	32.57
Depletion, depreciation and amortization	**7.67**	7.32	**21.98**	21.32	**10.54**	8.74	**0.25**	0.26	**13.06**	12.88
Field Operating Earnings Netback(1)	**31.34**	22.93	**24.61**	20.84	**7.74**	15.27	**(0.25)**	(0.26)	**19.88**	19.69
General and administrative	**—**	—	**—**	—	**—**	—	**1.51**	1.61	**1.51**	1.61
Other income	**—**	—	**—**	—	**—**	—	**—**	(0.02)	**—**	(0.02)
Interest expense	**—**	—	**—**	—	**—**	—	**2.54**	3.62	**2.54**	3.62
Finance costs	**—**	—	**—**	—	**—**	—	**1.32**	1.32	**1.32**	1.32
Current income tax (recovery)	**—**	—	**—**	—	**—**	—	**—**	(0.82)	**—**	(0.82)
Operating Earnings(1)									**14.51**	13.98
Effective royalty rate (%)(1)	**23.4**	23.2	**11.0**	10.7	**9.9**	8.9			**15.6**	15.1

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

Cold Lake Segment

Production at the Cold Lake segment for the three months ended December 31, 2024 decreased modestly to 59,732 boe per day compared to 59,845 boe per day in the same period of 2023. For the year ended December 31, 2024, production increased to 59,516 boe per day, compared to 55,768 boe per day in the same period of 2023. This increase was primarily due to strong well performance at the Company's Lindbergh and Tucker properties.

Oil and natural gas sales, net of blending, increased to $399.5 million ($72.62 per boe) during the three months ended December 31, 2024 compared to $349.3 million ($63.25 per boe) for the same quarter of 2023 primarily due to higher WCS Hardisty benchmark pricing and lower per barrel blend costs during the fourth quarter of 2024. During the year ended December 31, 2024 oil and natural gas sales, net of blending, increased to $1,646.2 million ($75.60 per boe) compared to $1,391.7 million ($68.37 per boe) for the same quarter of 2023. This increase was primarily due to higher sales volumes, increased WCS Hardisty benchmark pricing and lower per barrel blend costs compared to the same period of 2023.

The effective royalty rate for the three months and year ended December 31, 2024 increased to 33.3% and 23.4%, respectively, from 21.1% and 23.2% in the same periods of 2023. These increases were primarily attributable to the timing of eligibility of capital deductions.

Energy related production and operating expenses for the three months and year ended December 31, 2024 decreased to $29.9 million ($5.44 per boe) and $127.9 million ($5.87 per boe), respectively, compared to $39.6 million ($7.17 per boe) and $198.4 million ($9.75 per boe) in the same periods of 2023. These decreases were primarily attributable to the lower price of natural gas and electricity, and savings realized on carbon taxes as a result of carbon credit purchases.

Non-energy related production and operating expenses for the three months and year ended December 31, 2024 increased to $49.5 million ($9.00 per boe) and $196.0 million ($9.00 per boe), respectively, compared to $44.9 million ($8.13 per boe) and $173.9 million ($8.54 per boe), for the same periods of 2023. These increases were primarily due to increased chemical cost as a result of sulphur recovery units installed in the first quarter of 2024, which were fully operational in the second quarter of 2024.

For the three months ended December 31, 2024, transportation and processing expenses increased to $22.3 million ($4.05 per boe) from $18.7 million ($3.39 per boe) in the same period of 2023. For the year ended December 31, 2024, transportation and processing expenses increased to $87.7 million ($4.03 per boe) from $80.4 million ($3.95 per boe), in the same period of 2023. These increases were primarily attributable to increased bitumen transportation costs due to cost savings realized in 2023 due to the utilization of make-up rights.

Lloydminster Segment

Production from the Lloydminster segment for the three months and year ended December 31, 2024, decreased to 51,281 boe per day and 51,357 boe per day, respectively, compared to 52,987 boe per day and 53,930 boe per day in the same periods of 2023. These decreases were primarily due to lower production volumes from Saskatchewan thermal properties.

Oil and natural gas sales, net of blending, decreased to $374.7 million ($84.61 per boe) during the three months ended December 31, 2024 compared to $396.7 million ($84.38 per boe) for the same period of 2023. This decrease was primarily due to lower sales volumes. Oil and natural gas sales, net of blending, increased to $1,645.7 million ($88.00 per boe) during the year ended December 31, 2024 compared to $1,642.6 million ($82.74 per boe) for the same period of 2023. This increase was primarily attributable to higher WCS Hardisty and USGC benchmark pricing, partially offset by lower sales volumes.

The effective royalty rate for the three months and year ended December 31, 2024 increased to 13.9% and 11.0%, respectively, compared to 10.5% and 10.7% in the same periods of 2023. These increases were primarily attributable to the timing of eligibility of capital deductions.

Energy related production and operating expenses for the three months and year ended December 31, 2024 decreased to $26.7 million ($6.03 per boe) and $112.8 million ($6.03 per boe), respectively, compared to $31.4 million ($6.68 per boe) and $120.5 million ($6.07 per boe) for the same periods in 2023. These decreases were primarily attributable to the lower price of natural gas reducing gas purchases and lower price for electricity, partially offset by an increase in carbon taxes as certain thermal properties in Saskatchewan entered their first year of compliance.

Non-energy related production and operating expenses for the three months ended December 31, 2024 decreased to $44.9 million ($10.14 per boe) compared to $50.6 million ($10.76 per boe) in the same period of 2023. Non-energy related production and operating expenses for the year ended December 31, 2024 decreased to $203.7 million ($10.89 per boe), compared to $216.3 million ($10.90 per boe) for the same period in 2023. These decreases were primarily due to lower surface and downhole maintenance expenses resulting from lower production volumes.

For the three months ended December 31, 2024, transportation and processing expenses increased modestly to $66.3 million ($14.97 per boe) compared to $65.4 million ($13.91 per boe) in the same period of 2023. This increase per boe was primarily attributable to higher rail transportation charges due to an unfavorable CAD/USD exchange rate. For the year ended December 31, 2024, transportation and processing expenses decreased to $276.2 million ($14.77 per boe) from $293.7 million ($14.79 per boe) in the same period of 2023. This decrease was primarily due to lower sales volumes, partially offset by higher rail transportation charges due to an unfavorable CAD/USD exchange rate.

Montney Segment

Production at the Company's Montney segment for the three months and year ended December 31, 2024 increased to 76,190 boe per day and 72,207 boe per day, respectively, compared to 73,232 boe per day and 45,761 boe per day in the same periods of 2023. For the three months ended December 31, 2024, the increase was primarily due to new wells brought on stream in the fourth quarter of 2024. For the year ended December 31, 2024, these increases were primarily due to production from the properties acquired through the Pipestone Acquisition, which contributed 30,545 boe per day (December 31, 2023 - 7,651 boe per day) for the year ended December 31, 2024.

Oil and natural gas sales for the three months ended December 31, 2024 decreased to $250.4 million ($35.72 per boe) compared to $257.8 million ($38.26 per boe). This decrease was primarily due to lower commodity benchmark prices, offset by increased sales volumes. Oil and natural gas sales for the year ended December 31, 2024 increased to $963.0 million ($36.44 per boe) compared to $655.5 million ($39.24 per boe) in the same period of 2023. This increase was primarily due to incremental volumes from the Pipestone Acquisition, which contributed oil and natural gas sales of $440.6 million in year ended December 31, 2024. These increases were partially offset by a decrease in AECO benchmark prices, impacting natural gas sales.

For the three months ended December 31, 2024, effective royalty rate increased to 9.4% compared to 7.5% in the same quarter of 2023. This increase was primarily due to an increased weighting to production from wells that no longer qualify for incentive rates. For the year ended December 31, 2024, effective royalty rate increased to 9.9% compared to 8.9% in the same period of 2023 primarily due to a more favourable gas cost allowance credit in the comparative period.

Non-energy related production and operating expenses for the three months ended December 31, 2024 increased to $44.1 million ($6.29 per boe) compared to $37.8 million ($5.61 per boe) for the same period of 2023. Non-energy related production and operating expenses for the year ended December 31, 2024 increased to $163.9 million ($6.20 per boe), compared to $83.8 million ($5.02 per boe) in the same period of 2023. This increase was primarily attributed to increased gas processing fees at Grande Prairie and increased trucking costs at Kakwa due to delayed completion of a water disposal well.

Transportation and processing expenses for the three months ended December 31, 2024 increased to $55.6 million ($7.93 per boe) compared to $51.6 million ($7.66 per boe) in the same period of 2023. This increase was primarily attributable to higher sales volumes. Transportation and processing expenses for the year ended December 31, 2024 increased to $213.1 million ($8.06 per boe), compared to $108.8 million ($6.51 per boe) in the same period of 2023. These increases were primarily due to increased volumes added through the Pipestone Acquisition, which carry a higher per unit cost than the Company's other Montney assets as the production is processed through third-party facilities.

CAPITAL RESOURCES

Bank Credit Facilities

Covenant-Based Revolving Credit Facility and Term Credit Facility

As at December 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**"). In January 2025, the Company amended and restated the credit agreement governing the Revolving Credit Facility to, among other things, add a US$175.0 million covenant-based term facility (the "**Term Credit Facility**" and together with the Revolving Credit Facility, the "**Credit Facilities**") to its bank Credit Facilities (such credit agreement as so amended and restated, the "**Credit Agreement**") and to incorporate an accordion feature which permits the Company to increase the Credit Facilities available under the Credit Agreement by up to an additional $250.0 million, subject to the satisfaction of certain conditions.

The Credit Facilities have 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 either the Revolving Credit Facility or the Term 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. The Term Credit Facility was made available by way of a single advance, which was fully funded on January 29, 2025. Borrowings under the Term Credit Facility are available in U.S. dollars only and amounts repaid by the Company may not be re-borrowed. The proceeds of the Term Credit Facility were used to repay borrowings under the Revolving Credit Facility. In addition, the Revolving Credit Facility is not a borrowing base facility and does not require annual or semi-annual reviews.

The Credit Facilities bear 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 Credit Facilities are guaranteed by the Company's subsidiaries, and are 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, 2024, the Company had letters of credit outstanding under the Revolving Credit Facility of $1.6 million (December 31, 2023 - $10.6 million).

Foreign Exchange Risk Management on U.S. Denominated Bank 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 offset 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 December 31, 2024 the cross-currency swap asset was $28.6 million (December 31, 2023 – a liability of $39.6 million) and total debt includes an unrealized loss of $28.6 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 or losses in the annual financial statements.

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

Notional (US$)	Maturity Date	Contract Price
1,235.0 million	January 17, 2025	CAD/USD 1.4153

Financial Covenants

The Credit Agreement has three financial covenants which are calculated quarterly (as set out below).

(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, 2024, the Company was in compliance with such financial covenants, which are summarized in the following table:

As at	December 31, 2024
Total Debt to Adjusted EBITDA Ratio (≤ 4.00)(1)	**1.20**
Senior Debt to Adjusted EBITDA Ratio (≤ 3.50)(1)	**0.85**
Interest Coverage Ratio (≥ 3.50)(1)	**10.95**

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

Senior Notes

As at December 31, 2024, Strathcona had $719.2 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, 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, 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 December 31, 2024, the Company had letters of credit in the amount of $70.3 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 Credit Facilities 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 Credit Facilities are due at its maturity date.

The availability under the Revolving Credit Facility is summarized in the following table.

As at	**December 31, 2024**	December 31, 2023
Credit capacity[(1)]	**2,500.0**	2,300.0
Revolving Credit Facility debt at period end exchange rate	**(1,766.9)**	(2,036.3)
Unrealized loss (gain) on U.S. borrowings	**28.6**	(41.3)
Letters of credit outstanding	**(1.6)**	(10.6)
Availability	**760.1**	211.8

(1) In January 2025, the credit capacity under the Credit Facilities increased to approximately $2.75 billion with the addition of the US$175.0 million Term Credit Facility.

The Company carries a working capital deficiency as part of its current capital structure. As at December 31, 2024, the working capital deficiency was $545.6 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 or additional sources of capital will not be necessary. The Company's cash flow and the development of projects are subject to certain risk factors discussed in the "Risk Factors" section of this MD&A and the Annual Information Form for the year ended December 31, 2024.

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 imposition of tariffs or other tariff barriers will negatively impact the Company's realized prices, the timing of cash flows where production is directly exported by the Company and may increase certain of the Company's input costs.

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.

OTHER OBLIGATIONS

On August 9, 2024 Strathcona entered into a new asset-backed financing agreement backed by its interest in certain processing facility interests (the "**Financing Agreement**") for $112.4 million, which consideration was provided by way of the lender's concurrent assumption of premiums on bought calls from Strathcona.

The Financing Agreement has a maturity date of July 31, 2029 and bears interest at a fixed rate. Principal and interest payments are due monthly, with principal payments commencing February 1, 2025. The Company may also repurchase the processing facilities interest (the "**Repurchase Option**") at any time at the specified prices set out in the Financing Agreement. The Repurchase Option is a combination of the remaining principal balance and a varying option premium that is dependent on the time of exercise.

DECOMMISSIONING LIABILITY

At December 31, 2024, Strathcona's discounted decommissioning provision balance was $290.7 million (December 31, 2023 - $351.3 million) for future abandonment and reclamation of the Company's oil and natural gas properties. The reduction is primarily attributable to the change in the Company's credit adjusted risk-free rate from 8% in 2023 to 10% in 2024. During the year ended December 31, 2024, the Company incurred $35.7 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 December 31, 2024.

	Total	**<1 year**	**1-3 years**	**4-5 years**	**> 5 years**
Revolving Credit Facility[(1)]	**1,738.3**	—	1,738.3	—	—
Senior Notes[(2)]	**818.0**	49.4	768.6	—	—
Accounts payable and accrued liabilities	**918.7**	918.7	—	—	—
Risk management contract liability	**87.7**	44.6	43.1	—	—
Lease and other obligations[(3)]	**473.7**	91.4	151.6	143.8	86.9
Total	**4,036.4**	1,104.1	2,701.6	143.8	86.9

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

(2) Amounts represent repayment of the Senior Notes ($719.2 million) and associated interest payments ($98.8 million) based on the foreign exchange rate in effect on December 31, 2024.

(3) Amounts relate to undiscounted payments for lease and other obligations. The estimation of future cash payments related to other obligations reflects minimum required payments and may change based on the principal and interest payment options taken. See Note 7 of the annual financial statements.

As at December 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	**2,052.7**	284.4	507.2	427.2	833.9
Capital commitments	**139.0**	136.0	3.0	—	—
Other	**27.2**	13.8	10.9	2.5	—
Total	**2,218.9**	434.2	521.1	429.7	833.9

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 draws on 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 and which are not disclosed in the annual financial statements or notes thereto.

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 December 31, 2024 (December 31, 2023 – nil).

The following table summarizes the number of shares outstanding as at March 4, 2025:

Share Class	Shares Outstanding at March 4, 2025
Common Shares	214,235,608

The Company had no outstanding securities which are convertible into Common Shares or preferred shares as at March 4, 2025.

During the three months and year ended December 31, 2024, Strathcona declared and paid total dividends of $107.1 million, or $0.50 per Common Share ($nil - in the year ended December 31, 2023).

On March 4, 2025, the Board declared a quarterly dividend of $0.26 per Common Share to be paid on March 31, 2025 to all shareholders of record on March 21, 2025.

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. Certain of these risks and uncertainties are described at a high level within this MD&A. For additional information refer to the “Risk Factors” section in our Annual Information Form for the year ended December 31, 2024, 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.

Political and Social Events

Strathcona's results may be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to industrial activity generally or projects specifically, and the duration of regulatory reviews could impact Strathcona's existing operations and planned projects. This includes actions by regulatory bodies or other political actors to delay or deny necessary licenses and permits for Strathcona's activities or restrict the operation of third-party infrastructure that Strathcona relies on. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder (including Indigenous stakeholders) consultation requirements, may increase the cost of compliance or reduce or delay available business opportunities and have a material adverse effect on Strathcona's business, financial condition, results of operations and prospects.

Other government and political factors that could adversely affect Strathcona's financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements, including any changes to current tariff regimes and other non-tariff trade barriers. Further, the adoption of regulations mandating efficiency standards, and the use of alternative fuels or noncompetitive fuel components could adversely affect Strathcona's operations. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources, and the success of these initiatives may decrease demand for Strathcona's products.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the crude oil and natural gas industry, including the balance between economic development and environmental policy. The crude oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding crude oil and natural gas development, particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt Strathcona's activities.

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)	**2024**	2023	2022
Oil and natural gas sales	**5,336.4**	4,748.3	4,343.4
Net income	**603.7**	587.2	1358.2
Net income per share	**2.82**	2.94	0.63
Total assets	**10,977.5**	10,496.9	9,164.5
Total non-current liabilities	**4,027.7**	4,103.1	3,788.3
Dividends per share	**0.50**	—	—

SUMMARY OF QUARTERLY RESULTS

	2024				2023			
($ millions, unless otherwise indicated)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Operating results (boe/d)								
Average production volumes	**187,203**	178,235	181,766	185,122	186,064	147,461	143,778	144,160
Average sales volumes	**184,120**	178,391	185,841	182,862	184,360	148,874	143,239	146,877
Financial Results								
Oil and natural gas sales	**1,292.8**	1,272.5	1,472.3	1,298.8	1,287.6	1,300.2	1,112.8	1,047.7
Net Income (loss)	**87.9**	188.0	227.2	100.6	263.7	(41.1)	274.1	90.5
Net income (loss) per share	**0.41**	0.88	1.06	0.47	1.23	(0.02)	0.13	0.04
Cash flow from operating activities	**542.4**	521.9	519.7	408.8	570.0	430.5	343.1	181.1
Operating Earnings(1)	**190.0**	265.4	306.1	209.0	202.1	289.9	201.4	101.9
Funds from Operations(1)	**405.5**	528.7	547.6	455.6	470.8	425.3	389.2	276.9
Free Cash Flow(1)	**0.3**	200.6	247.3	157.9	150.8	158.0	152.6	36.1
Field Operating Income(1)	**474.7**	581.1	627.3	520.4	527.4	549.6	460.8	315.9
Field Operating Netback ($/boe)(1)	**28.03**	35.42	37.09	31.27	31.09	40.13	35.35	23.82
Field Operating Earnings(1)	**278.4**	354.8	398.2	298.6	299.9	378.0	290.1	152.8
Field Operating Earnings Netback ($/boe)(1)	**16.44**	21.63	23.54	17.94	17.68	27.60	22.25	11.48
Capital expenditures	**392.5**	319.6	298.0	286.1	307.8	260.2	231.7	228.7
Decommissioning expenditures	**12.7**	8.5	2.9	11.6	13.8	7.1	4.9	11.8
Total assets	**10,977.5**	10,663.3	10,670.9	10,597.8	10,496.9	9,588.9	9,451.2	9,289.5
Debt	**2,461.6**	2,449.9	2,435.6	2,642.5	2,665.0	2,787.6	2,898.2	3,041.7
Total equity	**5,823.7**	5,789.3	5,654.9	5,427.7	5,327.1	4,526.4	4,567.5	4,292.7
Common shares outstanding, end of period	**214.2**	214.2	214.2	214.2	214.2	2,186.7	2,186.7	2,186.5
Dividends per share	**0.25**	0.25	—	—	—	—	—	—

(1) A non-GAAP measure which does not have a standardized meaning under the Accounting Standards; 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 Pipestone Acquisition (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 asset 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 Pipestone Acquisition, 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 Pipestone Acquisition.

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”, “Crown royalties”, “Freehold royalties”, “Gross overriding royalties”, “Effective royalty rate”, “Production and operating – Energy”, “Production and operating – Non-energy”, “Production and operating – Energy ($/boe)”, “Production and operating – Non-energy ($/boe)”, “Transportation expense”, “Processing expense”, “Depletion expense”, “Depreciation and amortization expense”, “Operating Earnings”, “Funds from Operations”, “Free Cash Flow”, “Field Operating Income”, “Field Operating Netback”, “Field Operating Earnings”, and “Field Operating Earnings Netback”, which are not recognized measures under generally accepted accounting principles (“**GAAP**”) and do not have a standardized meaning prescribed by the Accounting Standards. 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”, “Field Operating Earnings Netback”, “Operating Earnings”, “Field 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 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 purchased product and blending cost from oil and natural gas sales and sales of purchased product and dividing by the respective sales volume. This ratio is useful to management when analyzing realized pricing against benchmark commodity prices.

The term “**Crown royalties**” is the portion of royalty expense reflecting amounts paid for production on land where petroleum oil and natural gas rights are owned by government bodies. The term “**Freehold royalties**” is the portion of royalty expense reflecting amounts paid for production on land where petroleum oil and natural gas rights are owned by private individuals or entities. The term “**Gross overriding royalties**” is the portion of royalty expense reflecting amounts paid to third parties when the WCS Hardisty heavy oil benchmark exceeds US$60.00/bbl. Management uses these metrics to analyze royalties under different royalty regimes. A quantitative reconciliation of Crown royalties, Freehold royalties and Gross overriding royalties to the most directly comparable GAAP financial measure, royalties, is contained under the heading “Royalties” of this MD&A.

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

The term “**Production and operating – Energy**” is the portion of production and operating expenses reflecting the cost of gas and propane fuel, utilities and carbon tax incurred to operate facilities. This metric allows management to analyze the portion of production and operating expenses subject to non-controllable market prices. A quantitative reconciliation of Production and operating - Energy to the most directly comparable GAAP financial measure, Production and operating expenses, is contained under the heading "Production and operating expenses" of this MD&A.

The term “**Production and operating – Non-energy**” is the portion of production and operating expenses reflecting the cost of operating activities relating to the production of resources. This metric allows management to analyze the portion of production and operating expenses that is within the Company's control. A quantitative reconciliation of Production and operating – Non-energy to the most directly comparable GAAP financial measure, Production and operating expenses, is contained under the heading “Production and operating expenses” of this MD&A.

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

The term “**Transportation expense**” is the portion of Transportation and processing expenses reflecting the cost of transporting oil and natural gas to the sales point. The term “**Processing expense**” is the portion of Transportation and processing expenses reflecting costs incurred to refine produced volumes to meet sales specifications. Management uses these metrics to analyze the different fee structures to deliver product to a location and specification for sale. A quantitative reconciliation of Transportation expense and Processing expense to the most directly comparable GAAP financial measure, Transportation and processing expenses, is contained under the heading “Transportation and processing expenses” of this MD&A.

The term “**Depletion expense**” is the portion of Depletion, depreciation and amortization expense reflecting the cost of development of oil and natural gas reserves. The term “**Depreciation and amortization expense**” is the portion of Depletion, depreciation and amortization expense reflecting the cost of a fixed asset over its expected useful life. Management uses these metrics to analyze the capital cost of different property, plant and equipment types. A quantitative reconciliation of Depletion expense and Depreciation and amortization expense to the most directly comparable GAAP financial measure, Depletion, depreciation and amortization expense, is contained under the heading “Depletion, depreciation and amortization (“DD&A”)” of this MD&A.

“**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 of 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, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Oil and natural gas sales	**1,292.8**	1,287.6	1,272.5	**5,336.4**	4,748.3
Sales of purchased products	**15.6**	11.3	44.4	**75.0**	46.3
Purchased product	**(16.1)**	(10.3)	(43.9)	**(75.0)**	(46.5)
Blending costs	**(267.7)**	(284.8)	(231.8)	**(1,081.5)**	(1,058.3)
Oil and natural gas sales, net of blending	**1,024.6**	1,003.8	1,041.2	**4,254.9**	3,689.8
Royalties	**208.5**	134.9	134.0	**662.7**	556.9
Production and operating	**197.2**	205.8	185.9	**811.7**	796.3
Transportation and processing	**144.2**	135.7	140.2	**577.0**	482.9
Field Operating Income	**474.7**	527.4	581.1	**2,203.5**	1,853.7
Depletion, depreciation and amortization	**196.3**	227.5	226.3	**873.5**	732.9
Field Operating Earnings	**278.4**	299.9	354.8	**1,330.0**	1,120.8
Field Operating Netback ($/boe)	**28.03**	31.09	35.42	**32.94**	32.57
Field Operating Earnings Netback ($/boe)	**16.44**	17.68	21.63	**19.88**	19.69

“**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 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, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Income (loss) and comprehensive income (loss)	**87.9**	263.7	188.0	**603.7**	587.2
Loss (gain) on risk management contracts	**(10.2)**	(129.1)	16.6	**44.0**	(69.6)
Foreign exchange (gain) loss	**47.7**	(20.9)	(6.8)	**68.2**	(22.1)
Transaction related costs	**0.3**	(1.3)	0.3	**1.0**	3.8
Unrealized (gain) loss on Sable remediation fund	**—**	(0.3)	(0.2)	**(0.1)**	(0.2)
Loss on settlement of other obligation	**—**	—	4.4	**4.4**	—
Deferred tax expense	**64.3**	90.0	63.1	**249.3**	296.2
Operating Earnings	**190.0**	202.1	265.4	**970.5**	795.3
Depletion, depreciation and amortization	**196.3**	227.5	226.3	**873.5**	732.9
Finance costs	**21.0**	21.6	21.9	**88.3**	75.3
Decommissioning government grant	**—**	—	—	**0.2**	(0.3)
(Loss) gain on risk management contracts - realized	**(5.4)**	19.5	(94.7)	**(107.0)**	(42.4)
Realized loss on deferred premium settlement	**—**	—	112.4	**112.4**	—
Foreign exchange (loss) gain - realized	**3.6**	0.1	(2.6)	**(0.5)**	1.4
Funds from Operations	**405.5**	470.8	528.7	**1,937.4**	1,562.2
Capital expenditures	**(392.5)**	(306.2)	(319.6)	**(1,295.6)**	(1,026.8)
Decommissioning costs	**(12.7)**	(13.8)	(8.5)	**(35.7)**	(37.9)
Free Cash Flow	**0.3**	150.8	200.6	**606.1**	497.5

"PDP Recycle Ratio”[(1)] is calculated by dividing the Organic Operating Netback by PDP Finding and Development Costs (**“PDP F&D”**[(1)]). PDP Recycle Ratio is used to measure the profit per barrel of oil to the cost of finding and developing that barrel of oil.

“Organic Operating Netback”[(1)] is used to assess the profitability and efficiency of Strathcona’s field operations before the impact of acquisitions.

A quantitative reconciliation of “Organic Operating Netback” to the most comparable GAAP measure, "Oil and natural gas sales”, is set forth below:

($ millions, unless otherwise indicated)	Year Ended December 31, 2024
Oil and natural gas sales	**5,336.4**
Sales of purchased products	**75.0**
Purchased product	**(75.0)**
Blending costs	**(1,081.5)**
Oil and natural gas sales, net of blending	**4,254.9**
Royalties	**662.7**
Production and operating	**811.7**
Transportation and processing	**577.0**
Field Operating Income	**2,203.5**
Operating income from properties acquired in the year	**-**
Organic Operating Income	**2,203.5**
Sales volumes (boe/d)	**182,794**
Less: sales volumes from properties acquired in the year (boe/d)	**-**
Organic Sales volumes (boe/d)	**182,794**
Organic Operating Netback ($/boe)	**32.94**

“PDP F&D Costs”(1) are calculated as Organic Capex plus changes in PDP future development costs (2024 - $56.0 million), divided by PDP reserve additions for the year (2024 – 95.7 MMboe), excluding the impact of acquisitions and dispositions. Management uses PDP F&D costs as a measure of capital efficiency for organic reserves development.

“Organic Capex”(1) is calculated as property, plant and equipment expenditures excluding capitalized overhead, expenditures on corporate assets and property, plant and equipment expenditures on acquired assets.

A quantitative reconciliation of “Organic Capex” to the most comparable GAAP measure, “Property, plant and equipment expenditures”, is set for below:

($ millions)	Year Ended December 31, 2024
Property, plant and equipment expenditures	**1,295.6**
Less: capitalized overhead	**(52.1)**
Less: expenditures on corporate assets	**(9.0)**
Less: property, plant and equipment expenditures on assets acquired in the year	**—**
Organic Capex	**1,234.5**

(1) Pertains to the Message to Shareholders included in Strathcona’s 2024 Annual Report which can be found at www.sedarplus.ca and www.strathconaresources.com.

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 result in actual results or changes to estimates that differ materially from current estimates. The Company's use of estimates and judgements in preparing the annual financial statements are discussed in Note 2 of the annual financial statements.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

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 Executive Chairman and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Executive Chairman and the 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, 2024. Based on that evaluation, the Executive Chairman and the Chief Financial Officer concluded that Strathcona's DC&P were effective as at December 31, 2024.

Internal control over financial reporting ("**ICFR**") is a set of processes designed to provide reasonable assurance that all assets are safeguarded, transaction are appropriately authorized, and facilitate the preparation of relevant, timely and reliable information. Because of its inherent limitations, ICFR, may not prevent or detect misstatements. Management has assessed the effectiveness of the Company'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 Organization of the Treadway Commission. Management concluded that the Company's ICFR was effective as of December 31, 2024. There were no changes made to the Company's ICFR during the year ended December 31, 2024 that have materially affected, or are reasonably likely to materially affect, the Company's 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 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 2024 and 2023, 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, 2024	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Cold Lake segment					
Heavy crude oil (bbl/d)	**—**	—	—	**—**	—
Light and medium crude oil (bbl/d)	**—**	—	—	**—**	—
Total crude oil (bbl/d)	**—**	—	—	**—**	—
Bitumen (bbl/d)	**59,732**	59,845	58,610	**59,516**	55,768
NGLs (bbl/d)	**—**	—	—	**—**	—
Total liquids (bbl/d)	**59,732**	59,845	58,610	**59,516**	55,768
Conventional natural gas (mcf/d)	**—**	—	—	**—**	—
Total (boe/d)	**59,732**	59,845	58,610	**59,516**	55,768
Lloydminster segment					
Heavy crude oil (bbl/d)	**50,997**	52,736	50,494	**51,107**	53,707
Light and medium crude oil (bbl/d)	**64**	40	30	**42**	42
Total crude oil (bbl/d)	**51,061**	52,776	50,524	**51,149**	53,749
Bitumen (bbl/d)	**—**	—	—	**—**	—
NGLs (bbl/d)	**4**	—	2	**2**	1
Total liquids (bbl/d)	**51,065**	52,776	50,526	**51,151**	53,750
Conventional natural gas (mcf/d)	**1,295**	1,260	1,150	**1,232**	1,080
Total (boe/d)	**51,281**	52,987	50,718	**51,357**	53,930
Montney segment					
Heavy crude oil (bbl/d)	**—**	—	—	**—**	—
Light and medium crude oil (bbl/d)	**553**	540	615	**609**	601
Total crude oil (bbl/d)	**553**	540	615	**609**	601
Bitumen (bbl/d)	**—**	—	—	**—**	—
NGLs (bbl/d)	**33,122**	30,509	30,553	**31,227**	20,388
Total liquids (bbl/d)	**33,675**	31,049	31,168	**31,836**	20,989
Conventional natural gas (mcf/d)	**255,091**	253,101	226,431	**242,224**	148,635
Total (boe/d)	**76,190**	73,233	68,907	**72,207**	45,762
Consolidated					
Heavy crude oil (bbl/d)	**50,997**	52,736	50,494	**51,107**	53,707
Light and medium crude oil (bbl/d)	**617**	580	645	**651**	642
Total crude oil (bbl/d)	**51,614**	53,316	51,139	**51,758**	54,349
Bitumen (bbl/d)	**59,732**	59,845	58,610	**59,516**	55,768
NGLs (bbl/d)	**33,126**	30,509	30,555	**31,229**	20,389
Total liquids (bbl/d)	**144,472**	143,670	140,304	**142,503**	130,506
Conventional natural gas (mcf/d)	**256,386**	254,361	227,581	**243,456**	149,715
Total (boe/d)	**187,203**	186,064	178,235	**183,080**	155,459

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 2025 production and capital spending guidance; the declaration and payment of dividends, including the amount and timing thereof; expected impacts of tariffs on Strathcona's operations, including Local Sales, and the effectiveness of Strathcona's mitigation measures; 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; and sources of funding for the Company's capital program, working capital deficiency 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; Strathcona's ability to declare and pay dividends; expectations regarding the impact of tariffs on Strathcona's operations and its ability to effectively mitigate the impact thereof; 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, including expectations regarding the current and future carbon tax regime and regulations; ability to obtain federal CCS investment tax credit and other grants to fund Strathcona's portion of the CCS investment under the arrangement. In addition, certain forward-looking information with respect to the Company's 2025 guidance assumes commodity prices and exchange rates of: US$70 / bbl WTI, US$13 / bbl WCS-WTI differential, 1.38 USD-CAD and C$3 / GJ 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, including the imposition of tariffs or other trade barriers, 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; failure to achieve anticipated results of its operations; competition from other producers; inability to retain drilling rigs and other services; failure to realize the anticipated benefits of the Company's acquisitions or corporate reorganizations; incorrect assessment of the value of acquisitions; delays resulting from or inability to obtain required regulatory approvals; the risk that the arrangement with Canada Growth Fund may not provide the anticipated benefits to Strathcona; the risk that Canada Growth Fund may not meet its funding obligations under the terms of the arrangement; the risk that the CCS facilities may not reduce emissions attributable to Strathcona's operations; the risk that the CCS investment tax credit and other grants may not be available or available on the terms expected; 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 the Company's Management's Discussion and Analysis and Annual Information Form for the year ended December 31, 2024, a copy of each of which is available under the Company’s profile on SEDAR+ at www.sedarplus.ca.

Declaration of dividends is at the sole discretion of the board of directors of Strathcona and will continue to be evaluated on an ongoing basis. There are numerous factors that may result in Strathcona changing, suspending or discontinuing its quarterly dividends, including changes to its free cash flow, operating results, capital requirements, financial position, debt levels, market conditions or corporate strategy and the need to comply with requirements under the Credit Agreement and applicable laws respecting the declaration and payment of dividends. There are no assurances as to the continuing declaration and payment of future dividends or the amount or timing of any such dividends.

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, 2024 and the annual financial statements, can be found at: www.sedarplus.ca and www.strathconaresources.com.