STRATHCONA RESOURCES LTD

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 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 August 13, 2024 and should be read in conjunction with the Company’s unaudited condensed consolidated interim financial statements (and related notes) as at and for the three and six months ended June 30, 2024 and 2023 (the “**interim financial statements**”) and the Company’s audited consolidated financial statements (and related notes) for the years ended December 31, 2023 and December 31, 2022 (the “**annual financial statements**”). The interim financial statements and annual financial statements have been prepared in accordance with International Financial Reporting Standards (“**IFRS**”) as issued by the International Accounting Standards Board (“**IASB**”), in Canadian dollars, except where indicated otherwise. The interim financial statements and annual financial statements and MD&A of Strathcona have been prepared by management and were approved by the Company’s Board of Directors.

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

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

DESCRIPTION OF BUSINESS

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

The significant differences in financial and operational results of the Company for the three and six months ended June 30, 2024 compared to the three and six months ended June 30, 2023 within this MD&A are primarily the result of the Pipestone Acquisition. Refer to Note 4 of the annual financial statements for further details regarding the Pipestone Acquisition.

At June 30, 2024, approximately 90.8% of the Company’s shares were owned by certain limited partnerships comprising Waterous Energy Fund and its affiliates (collectively, “**WEF**”).

RECENT DEVELOPMENTS

On July 10, 2024, Strathcona announced a strategic partnership with Canada Growth Fund (“CGF”) for the development of carbon capture and sequestration (“CCS”) infrastructure on Strathcona’s steam-assisted gravity drainage oil sands facilities across Saskatchewan and Alberta. Under the terms of the arrangement, CGF has agreed to invest up to $1.0 billion toward CCS infrastructure projects on Strathcona’s assets, with an initial commitment of up to $500 million. Subject to each of Strathcona and CGF providing a positive final investment decision in respect of a CCS project pursued by Strathcona, Strathcona will construct, operate and own the CCS infrastructure, with 50% of the initial capital costs of such project funded by CGF and 50% by Strathcona. Substantially all of Strathcona’s share of capital costs is expected to be recouped through the federal CCS investment tax credit and other grants. Strathcona is commencing its final stage front end engineering design work for its first commercial project, with a targeted final investment decision date in mid-2025.

On July 15, 2024, Strathcona exercised its option to terminate the then existing asset-backed financing arrangement for consideration of $157.6 million.

On August 9, 2024, Strathcona entered into a new asset-backed financing agreement backed by its interest in certain processing facility assets for $112.4 million, which consideration was provided by way of the lender's concurrent assumption of certain outstanding premiums on hedging transactions from Strathcona.

On August 13, 2024, the board of directors of Strathcona declared its inaugural quarterly dividend of $0.25 per common share to be paid on September 27, 2024 to shareholders of record on September 16, 2024.

2024 GUIDANCE

Strathcona's 2024 capital budget remains unchanged at $1.3 billion as does its 2024 oil and total liquids production guidance.

In light of continued weakness in natural gas prices, Strathcona is electing to further defer production from the Groundbirch 13-25 pad. This deferral, combined with a previously unscheduled third-party gas facility outage late in the third quarter and third-party outages experienced in the second quarter, are expected to reduce full year natural gas production by approximately 15 MMcf per day. Strathcona's updated full-year production guidance is now expected to be in the range of 185,000 to 190,000 boe per day, with an increased liquids weighting of 79% (from 78%) and an increased oil weighting of 72% (from 71%).

	2024 Guidance - Previously Reported(1)	2024 Guidance - Amended
Production (boe/d)	**187,500 – 192,500**	**185,000 – 190,000**
Capital expenditures ($ billions)	**1.3**	**1.3**

(1) As disclosed in the Company's March 26, 2024 news release.

PRODUCTION VOLUMES

	Three Months Ended			Six Months Ended	
	June 30, 2024	June 30, 2023	March 31, 2024	**June 30, 2024**	June 30, 2023
Bitumen (bbl/d)	**59,581**	53,825	60,150	**59,865**	52,469
Heavy oil (bbl/d)	**51,111**	53,470	51,835	**51,473**	55,446
Condensate and light oil (bbl/d)	**20,120**	10,600	19,279	**19,700**	9,341
Total oil production (bbl/d)	**130,812**	117,895	131,264	**131,038**	117,256
Other NGLs (bbl/d)	**11,426**	7,780	11,738	**11,582**	8,139
Natural gas (mcf/d)	**237,170**	108,612	252,720	**244,945**	111,442
Total (boe/d)	**181,766**	143,778	185,122	**183,444**	143,968
% oil and condensate	**72 %**	82 %	71 %	**71 %**	81 %
% liquids	**78 %**	87 %	77 %	**78 %**	87 %

Production volumes increased by 26% (or 37,988 boe per day) for the three months ended June 30, 2024 to an average of 181,766 boe per day compared to 143,778 boe per day for the same quarter of 2023. The increase is primarily attributable to production from properties added through the Pipestone Acquisition, which was completed in the fourth quarter of 2023. The Pipestone Acquisition contributed production of 30,746 boe per day in the three months ended June 30, 2024, composed of condensate and light oil production of 8,988 bbl per day, other NGLs of 3,156 bbl per day and natural gas of 111,611 mcf per day. The remaining production increase is attributable to strong well results from the Company's capital program.

Production volumes increased by 27% (or 39,476 boe per day) for the six months ended June 30, 2024 to an average of 183,444 boe per day compared to 143,968 boe per day for the same period of 2023. The increase is primarily attributable to production from properties added through the Pipestone Acquisition, which was completed in the fourth quarter of 2023. The Pipestone Acquisition contributed production of 32,375 boe per day in the six months ended June 30, 2024, composed of condensate and light oil production of 9,425 bbl per day, other NGLs of 3,373 bbl per day and natural gas of 117,459 mcf per day.

Production volumes decreased by approximately 2% during the three months ended June 30, 2024 compared to the three months ended March 31, 2024. The decrease is primarily the result of reduced gas production resulting from planned and unplanned outages at third-party processing plants at Grande Prairie, shut-in volumes for completion operations at Groundbirch and Kakwa, and ongoing debottleneck work at the Company's Cold Lake thermal assets.

SALES VOLUMES

	Three Months Ended			Six Months Ended	
	June 30, 2024	June 30, 2023	March 31, 2024	**June 30, 2024**	June 30, 2023
Bitumen (bbl/d)	**59,333**	53,892	60,422	**59,877**	52,521
Heavy oil (bbl/d)	**55,434**	52,865	49,303	**52,368**	56,473
Condensate and light oil (bbl/d)	**20,120**	10,600	19,279	**19,700**	9,341
Total oil production (bbl/d)	**134,887**	117,357	129,004	**131,945**	118,335
Other NGLs (bbl/d)	**11,426**	7,780	11,738	**11,582**	8,139
Natural gas (mcf/d)	**237,170**	108,612	252,720	**244,945**	111,442
Total (boe/d)	**185,841**	143,239	182,862	**184,351**	145,048

Sales volumes will trend with production volumes, except in cases of an inventory build or an inventory draw. Strathcona carries inventory on rail cars in transit to the US Gulf Coast, on pipelines and in storage tanks. At the end of the first quarter of 2024, heavy oil inventory volumes on rail increased due to a delay in the commissioning of an expansion to a unit train offloading facility in the US Gulf Coast. The facility was purpose-built for Strathcona to better supply a local US Gulf Coast refiner that entered into a new crude purchase agreement with the Company at a premium to WCS Houston. The facility was fully operational for the second quarter of 2024 which resulted in the sale of volumes in inventory throughout the second quarter and a reduction in inventory levels at June 30, 2024.

BUSINESS ENVIRONMENT

	Three Months Ended			Six Months Ended	
	June 30, 2024	June 30, 2023	March 31, 2024	**June 30, 2024**	June 30, 2023
Benchmark Pricing					
US$/bbl unless otherwise indicated					
WTI(1)	**80.57**	73.78	76.96	**78.76**	74.96
WCS Hardisty(2)	**66.96**	58.64	57.65	**62.30**	54.95
WCS USGC(3)	**74.69**	66.98	69.89	**72.29**	64.73
WTI-WCS Hardisty differential	**(13.61)**	(15.14)	(19.31)	**(16.46)**	(20.01)
WTI-WCS USGC differential	**(5.88)**	(6.79)	(7.07)	**(6.48)**	(10.22)
NYMEX-AECO differential (US$/MMbtu)(4)	**(0.95)**	(0.53)	(0.88)	**(0.91)**	(0.53)
Condensate differential(5)	**(3.43)**	(1.44)	(4.18)	**(3.80)**	1.13
Average FX rate (C$/US$)	**1.3684**	1.3430	1.3488	**1.3586**	1.3475
CAD$/bbl unless otherwise indicated					
WTI(1)	**110.25**	99.11	103.81	**107.03**	101.01
WCS Hardisty(2)	**91.63**	78.76	77.77	**84.70**	74.03
WCS USGC(3)	**102.20**	89.97	94.28	**98.24**	87.22
AECO 5A (C$/mcf)(6)	**1.18**	2.45	2.50	**1.84**	2.83
Condensate par at Edmonton	**105.56**	97.19	98.18	**101.87**	102.55
AESO weighted average pool price (C$/MWh)(7)	**45.35**	164.31	100.96	**73.16**	153.65
CORRA (%)(8)	**4.95**	4.57	5.03	**4.99**	4.50
CDOR (%)(9)	**5.20**	5.02	5.36	**5.28**	4.95

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

WTI crude oil prices increased nearly 5% in the second quarter of 2024 compared to the first quarter of 2024 as there was a strengthening of global oil demand due to summer gasoline demand and OPEC+ continued oil cuts.

The WTI-WCS Hardisty differential strengthened by 30% in the second quarter of 2024 compared to the first quarter due to the Trans Mountain Pipeline Expansion (TMX) coming online in May 2024. This expansion added approximately 590,000 bbl per day of heavy oil blend transport capacity to the existing system. In addition, increasing US and Canadian refinery runs in the second quarter of 2024 also contributed to the strengthening in the WTI-WCS differential.

The WTI-WCS USGC differential strengthened by 17% in the second quarter of 2024 due to increased US refinery runs. Concerns regarding less supply being delivered to the Gulf Coast after the startup of TMX contributed to a strengthening of the USGC WCS differential to WTI in the second quarter of 2024 compared to the first quarter of 2024.

AECO 5A natural gas prices decreased 53% in the second quarter of 2024 compared to the first quarter of 2024. Second quarter 2024 inventories of natural gas in North America remained higher than any point in the last five years due to a warmer than anticipated winter season, which lead to decreased demand, and resulted in weakening of natural gas pricing.

REVENUE AND REALIZED PRICES

Oil and Natural Gas Sales – Net of Blending

($ millions, unless otherwise indicated)	Three Months Ended **June 30, 2024**	June 30, 2023	March 31, 2024	Six Months Ended **June 30, 2024**	June 30, 2023
Bitumen blend	**703.3**	548.0	623.7	**1,327.0**	1,018.2
Heavy oil, blended and raw	**527.5**	434.6	416.5	**944.0**	882.3
Condensate and light oil	**188.7**	90.8	165.8	**354.5**	164.3
Other natural gas liquids	**24.6**	14.5	30.3	**54.9**	36.5
Natural gas	**28.2**	24.9	62.5	**90.7**	59.2
Oil and natural gas sales	**1,472.3**	1,112.8	1,298.8	**2,771.1**	2,160.5
Gain (loss) purchased product	**—**	(0.6)	—	**—**	(1.6)
Bitumen – blending cost	**(244.9)**	(209.0)	(251.8)	**(496.7)**	(445.0)
Heavy oil – blending cost	**(42.5)**	(40.8)	(42.8)	**(85.3)**	(90.0)
Oil and natural gas sales, net of blending(1)	**1,184.9**	862.4	1,004.2	**2,189.1**	1,623.9

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

Oil and natural gas sales, net of blending, increased 37% for the three months ended June 30, 2024 to $1,184.9 million compared to $862.4 million for the same quarter in 2023. This increase is primarily attributable to increased sales volumes from the Cold Lake Thermal segment and the properties acquired in the Pipestone Acquisition along with stronger oil benchmark pricing. These increases were partially offset by increased blending costs due to increased bitumen production, higher condensate benchmark pricing, and lower natural gas pricing.

Oil and natural gas sales, net of blending, increased 35% for the six months ended June 30, 2024 to $2,189.1 million compared to $1,623.9 million for the same period in 2023. This increase is primarily attributable to increased sales volumes from the Cold Lake Thermal segment and the properties acquired in the Pipestone Acquisition along with stronger oil benchmark pricing. These increases were partially offset by a decrease in heavy oil sales volumes at the Lloydminister Heavy Oil segment, increased blending costs due to increased bitumen production, partially offset by lower condensate and natural gas benchmark pricing.

Oil and natural gas sales, net of blending, for the three months ended June 30, 2024 increased by 18% from the first quarter of 2024 due to stronger oil benchmark pricing, decreased blending costs primarily driven lower blending ratios due to warmer weather and the sale of heavy oil volumes from inventory.

Average Realized Prices

	Three Months Ended			Six Months Ended	
	June 30, 2024	June 30, 2023	March 31, 2024	**June 30, 2024**	June 30, 2023
Bitumen blend ($/bbl)[1][2]	**84.83**	69.12	67.66	**76.17**	60.13
Heavy oil, blended and raw ($/bbl)[1][2]	**96.15**	81.86	83.29	**90.10**	77.51
Condensate and light oil ($/bbl)	**103.06**	94.13	94.50	**98.87**	97.19
Realized oil ($/bbl)	**92.23**	77.12	77.64	**85.09**	71.35
Other natural gas liquids ($/bbl)	**23.66**	20.48	28.37	**26.04**	24.78
Natural gas ($/mcf)	**1.31**	2.52	2.72	**2.04**	2.93
Combined ($/boe)	**70.06**	66.16	60.35	**65.24**	61.85

(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 IFRS; see “Specified Financial Measures” section of this MD&A.

Combined realized price increased 6% for the three months ended June 30, 2024 to $70.06 per boe compared to $66.16 per boe in the same quarter of 2023. The increase is primarily attributable to improved benchmark commodity prices on oil, partially offset by a decrease in natural gas benchmark pricing.

Combined realized price increased 5% for the six months ended June 30, 2024 to $65.24 per boe compared to $61.85 per boe in the same period of 2023. The increase is primarily attributable to improved benchmark commodity prices for oil, partially offset by decreases in natural gas benchmark pricing.

Combined realized price increased 16% for the three months ended June 30, 2024 to $70.06 per boe compared to $60.35 per boe for the three months ended March 31, 2024. The increase is primarily attributable to improved benchmark commodity prices on oil, and lower blending ratios driven by warmer weather. These increases were partially offset by a decrease in natural gas benchmark pricing.

ROYALTIES

	Three Months Ended			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2024**	June 30, 2023	March 31, 2024	**June 30, 2024**	June 30, 2023
Crown royalties[1]	**143.0**	77.4	99.6	**242.6**	176.5
Freehold royalties[1]	**7.9**	8.3	8.2	**16.1**	15.5
Gross overriding royalties[1]	**34.4**	12.5	14.4	**48.8**	18.6
Other royalties	**8.7**	8.0	4.0	**12.7**	8.7
Royalties	**194.0**	106.2	126.2	**320.2**	219.3
Effective royalty rate (%)[1]	**16.4 %**	12.3 %	12.6 %	**14.6 %**	13.5 %

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

For the three and six months ended June 30, 2024, the average effective royalty rate was 16.4% and 14.6%, respectively, compared to 12.3% and 13.5% for the same periods in 2023. For the three months ended June 30, 2024, the average effective royalty rate increased to 16.4% from 12.6% in the first quarter of 2024. These increases were primarily the result of increased benchmark commodity prices in the respective periods.

PRODUCTION AND OPERATING EXPENSES

($ millions, unless otherwise indicated)	Three Months Ended **June 30, 2024**	June 30, 2023	March 31, 2024	Six Months Ended **June 30, 2024**	June 30, 2023
Production and operating – Energy(1)	**64.9**	79.7	78.8	**143.7**	168.4
Production and operating – Non-energy(1)	**149.5**	110.9	135.4	**284.9**	226.8
Production and operating expenses	**214.4**	190.6	214.2	**428.6**	395.2
Production and operating – Energy ($/boe)(1)	**3.84**	6.11	4.74	**4.28**	6.41
Production and operating – Non-energy ($/boe)(1)	**8.84**	8.51	8.14	**8.49**	8.64
Production and operating expenses ($/boe)	**12.68**	14.62	12.88	**12.77**	15.05

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

Production and operating expenses increased to $214.4 million ($12.68 per boe) and $428.6 million ($12.77 per boe) for the three and six months ended June 30, 2024, respectively, from $190.6 million ($14.62 per boe) and $395.2 million ($15.05 per boe) in the same periods of 2023.

These increases are primarily attributable to the Pipestone Acquisition, which added $21.3 million and $43.8 million in incremental non-energy costs in the three and six months ended June 30, 2024, respectively, compared to the same periods of 2023. Increases were also observed in chemical costs as a result of sulphur recovery units installed at the Company's Cold Lake Thermal segment in the first quarter of 2024 becoming fully operational in the second quarter, increases in surface maintenance costs and an increase in sales volumes during the current period which resulted in operating expenses being recognized from inventory. These increases were partially offset by a decrease in energy production and operating expenses primarily due to lower natural gas and electricity prices, partially offset by increases in the carbon tax price per tonne impacting the Company's thermal properties.

On a per boe basis for the three and six months ended June 30, 2024, production and operating expenses decreased from the same periods in 2023 primarily due to the incremental production from the Pipestone Acquisition assets, which have a lower production and operating cost structure compared to the Cold Lake Thermal and Lloydminster Heavy Oil segments.

Non-energy production and operating costs increased by 10% for the three months ended June 30, 2024 compared to the three months ended March 31, 2024. The increase is primarily due to increases in chemical costs from the sulphur recovery units that were fully operational for the second quarter and an increase in sales volumes during the current period which resulted in operating expenses being recognized from inventory. These increases were partially offset by a decrease in processing and handling fees driven by a decrease in natural gas volumes at the Company's Montney segment.

TRANSPORTATION AND PROCESSING EXPENSES

($ millions, unless otherwise indicated)	Three Months Ended **June 30, 2024**	 June 30, 2023	 March 31, 2024	Six Months Ended **June 30, 2024**	 June 30, 2023
Transportation expenses[1]	**123.2**	97.9	114.8	**238.0**	218.6
Processing expenses[1]	**26.0**	6.9	28.6	**54.6**	14.1
Transportation and processing expenses	**149.2**	104.8	143.4	**292.6**	232.7
$ per boe	**8.82**	8.04	8.62	**8.72**	8.86

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

For the three and six months ended June 30, 2024, transportation and processing expenses increased to $149.2 million ($8.82 per boe) and $292.6 million ($8.72 per boe) from $104.8 million ($8.04 per boe) and $232.7 million ($8.86 per boe) in the same periods of 2023. The increases are primarily the result of increased production volumes attributable to the Pipestone Acquisition which added $30.3 million and $65.8 million in transportation and processing expenses in the three and six months ended June 30, 2024, respectively. Sales of heavy oil volumes from inventory and increased production as a result of the Company’s capital program also contributed to the increases. Production from the properties acquired in the Pipestone Acquisition carry additional processing expenses with flow-through capital charges, as the majority of the production is processed through third party facilities.

Transportation and processing expenses increased by 4% for the three months ended June 30, 2024 to $149.2 million ($8.82 per boe) from $143.4 million ($8.62 per boe) in the first quarter of 2024. The increase was primarily due to increased heavy oil rail transportation costs as a result of sales from inventory at the Lloydminister Heavy Oil segment. This increase was partially offset by a decrease to gas transportation and processing costs at the Company’s Montney segment driven by a slight decrease in volumes.

DEPLETION, DEPRECIATION AND AMORTIZATION (“DD&A”)

($ millions, unless otherwise indicated)	Three Months Ended **June 30, 2024**	 June 30, 2023	 March 31, 2024	Six Months Ended June 30, 2024	 June 30, 2023
Depletion expense[1]	**216.0**	164.1	208.9	**424.9**	321.2
Depreciation and amortization expense[1]	**13.1**	6.6	12.9	**26.0**	12.6
DD&A	**229.1**	170.7	221.8	**450.9**	333.8
$ per boe	**13.55**	13.10	13.33	**13.44**	12.71

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

DD&A expense increased by 34% and 35% for the three and six months ended June 30, 2024 to $229.1 million ($13.55 per boe) and $450.9 million ($13.44 per boe), respectively, compared to $170.7 million ($13.10 per boe) and $333.8 million ($12.71 per boe) for the same periods of 2023. This increase was primarily due to an increase in production volumes from the comparative periods in 2023.

DD&A expense increased 3% for the three months ended June 30, 2024 to $229.1 million ($13.55 per boe) compared to $221.8 million ($13.33 per boe) for the three months ended March 31, 2024. This is predominantly due to an increase in heavy oil sales volumes from inventory, partially offset by a slight decrease in production volumes from the prior quarter.

GENERAL AND ADMINISTRATION EXPENSES ("G&A")

	Three Months Ended			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2024**	June 30, 2023	March 31, 2024	**June 30, 2024**	June 30, 2023
G&A expenses	**25.2**	20.8	22.0	**47.2**	46.7
$ per boe	**1.49**	1.59	1.32	**1.40**	1.78

For the three and six months ended June 30, 2024, G&A expenses increased to $25.2 million ($1.49 per boe) and $47.2 million ($1.40 per boe), respectively, from $20.8 million ($1.59 per boe) and $46.7 million ($1.78 per boe) for the same periods in 2023. These increases were primarily the result of higher staffing levels from the growth of the business and increased information technology costs.

G&A expenses increased during the three months ended June 30, 2024, to $25.2 million ($1.49 per boe) from $22.0 million ($1.32 per boe) for three months ended March 31, 2024, primarily due to higher personnel and information technology costs.

INTEREST

	Three Months Ended			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2024**	June 30, 2023	March 31, 2024	**June 30, 2024**	June 30, 2023
Interest expense	**43.7**	50.3	45.4	**89.1**	104.4
Weighted average interest rate (%)	**6.3 %**	6.4 %	6.4 %	**6.3 %**	6.6 %

Interest expense decreased 13% and 15% for the three and six months ended June 30, 2024 to $43.7 million and $89.1 million, respectively, compared to $50.3 million and $104.4 million for the same periods of 2023. These decreases are primarily the result of lower debt levels and lower interest rates.

During the six months ended June 30, 2024, the Company recorded $23.4 million in interest expense on the Senior Notes (as defined in the "Capital Resources" section of this MD&A) (June 30, 2023 – $23.2 million); and $79.9 million in interest expense on the bank credit facilities (June 30, 2023 - $85.3 million); and a realized gain of $14.2 million on interest rate swaps (June 30, 2023 - $4.1 million).

Interest expense decreased 4% for the three months ended June 30, 2024 to $43.7 million compared to $45.4 million for the first quarter of 2024 which was primarily the result of lower debt balances and lower interest rates.

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

	Three Months Ended			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2024**	June 30, 2023	March 31, 2024	**June 30, 2024**	June 30, 2023
Accretion of lease obligations	**6.1**	2.8	6.2	**12.3**	5.6
Accretion of decommissioning provision	**7.0**	7.3	7.1	**14.1**	14.5
Amortization of debt issuance costs	**5.0**	3.1	4.1	**9.1**	6.3
Accretion of other obligations	**5.0**	4.6	4.9	**9.9**	9.2
Finance costs	**23.1**	17.8	22.3	**45.4**	35.6

For the three and six months ended June 30, 2024, finance costs increased by 30% to $23.1 million and 28% to $45.4 million, respectively, compared to $17.8 million and $35.6 million in the same periods of 2023. These increases are 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. 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.

Finance costs remained consistent during the three months ended June 30, 2024 compared to the three months ended March 31, 2024.

TAX POOLS

As at June 30, 2024, the Company had approximately $5,699.7 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	**June 30, 2024**	December 31, 2023
Canadian oil and gas property expenditures	10 %	**851.8**	893.4
Canadian development expenditures(1)	30 %	**1,271.8**	1,168.8
Canadian exploration expenditures(1)	100 %	**26.3**	34.1
Undepreciated capital costs(2)	4 % - 55 %	**1,389.8**	1,371.0
Non-capital losses	100 %	**1,733.3**	2,173.1
Other(1)(3)		**426.7**	440.7
Total tax pools		**5,699.7**	6,081.1

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

(2) As at June 30, 2024, approximately 96% (December 31, 2023 – 96%) of costs in this pool have an annual deduction rate of 25%.

(3) Other tax deductions include scientific research and experimental development costs and credits and financing costs. As at June 30, 2024, approximately 88% (December 31, 2023 – 89%) of these deductions have an annual deduction rate of 100%.

RISK MANAGEMENT

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

Credit Risk

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

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

Market Risk

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

Commodity Price Risk

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

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

Term	Contract(1)	Index	Currency	Volume	Units	Price
May 1, 2024 - Dec 31, 2024	Swap	WCS	USD	10,000	bbl/d	($14.25)
Dec 1, 2024 - Mar 31, 2025	Collar	AECO	CAD	30,000	GJ/d	$2.50/$3.51
Oct 1, 2024 - Dec 31, 2024	Collar	WTI	USD	30,000	bbl/d	$70.00/$87.99

(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 Revolving Credit Facility in USD and the Senior Notes are denominated in USD. The Company actively manages foreign exchange risk using foreign exchange derivatives.

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

Term	Contract	USD per Month	CAD/USD Floor	CAD/USD Ceiling
Mar 1, 2024 - Feb 27, 2026	Collar	60.0 million	1.2500	1.3800

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

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

Interest Rate Risk

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

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

Notional (C$)	Term	Contract	Index	Contract Price
1,500.0 million	Jul 2, 2024 - Apr 30, 2028	Swap	CORRA	3.1357%

For a listing of the Company's commodity contracts, foreign exchange and interest rate contracts outstanding as at June 30, 2024 refer to Note 12 in the interim financial statements.

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

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

	Three Months Ended			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2024**	June 30, 2023	March 31, 2024	**June 30, 2024**	June 30, 2023
Realized loss (gain) on risk management contracts[1]	**11.4**	0.4	(4.5)	**6.9**	5.8
Unrealized (gain) loss on risk management contracts[2]	**(13.5)**	(142.5)	44.2	**30.7**	(212.1)
Total (gain) loss on risk management contracts	**(2.1)**	(142.1)	39.7	**37.6**	(206.3)
Realized loss (gain) on risk management contracts per boe	**0.67**	0.03	(0.27)	**0.21**	0.22

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

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

Strathcona realized a loss on risk management contracts of $11.4 million and $6.9 million, respectively, for the three and six months ended June 30, 2024, compared to a loss of $0.4 million and $5.8 million in the same periods of 2023. The Company realized a loss on risk management contracts of $11.4 million in the second quarter, compared to a realized gain of $4.5 million in the first quarter 2024. The realized losses are due to realized commodity benchmark prices in comparison to contracted hedge pricing.

As at June 30, 2024, the mark-to-market value of risk management contracts was a net liability of $134.5 million (December 31, 2023 - net liability of $103.7). 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 12 to the interim financial statements.

CAPITAL EXPENDITURES

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

	Three Months Ended			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2024**	June 30, 2023	March 31, 2024	**June 30, 2024**	June 30, 2023
Cold Lake Thermal	**78.5**	79.3	58.9	**137.4**	158.3
Lloydminster Heavy Oil	**97.9**	80.1	95.7	**193.6**	165.1
Montney	**119.1**	69.6	129.9	**249.0**	131.0
Corporate	**2.5**	2.7	1.6	**4.1**	6.0
Capital expenditures	**298.0**	231.7	286.1	**584.1**	460.4

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

	Three Months Ended			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2024**	June 30, 2023	March 31, 2024	**June 30, 2024**	June 30, 2023
Drilling, completion and equipping	**163.1**	128.3	165.4	**328.5**	262.3
Facilities and pipelines	**96.1**	68.3	74.3	**170.4**	136.2
Recompletion, workovers and polymer powder	**24.2**	18.5	29.0	**53.2**	33.3
Capitalized G&A and other expenditures	**14.6**	16.6	17.4	**32.0**	28.6
Capital expenditures	**298.0**	231.7	286.1	**584.1**	460.4

For the three months ended June 30, 2024, drilling, completion and equipping activities accounted for 55% of capital expenditures as the Company drilled 56 new wells during the quarter; 16 in Cold Lake Thermal, 33 in Lloydminster Heavy Oil and 7 in Montney. For the six months ended June 30, 2024, drilling, completion and equipping activities accounted for 56% of capital expenditures as the Company drilled 126 new wells during the year; 26 at Cold Lake Thermal, 84 in Lloydminster Heavy Oil and 16 in Montney.

Capital expenditures increased 29% and 27% for the three and six months ended June 30, 2024 to $298.0 million and $584.1 million, respectively, compared to $231.7 million and $460.4 million for the same periods of 2023. Capital expenditures increased 4% for the three months ended June 30, 2024 to $298.0 million compared to $286.1 million for the first quarter of 2024. While timing of the expenditures in the 2024 program will vary from quarter to quarter, full year capital guidance remains unchanged at $1.3 billion.

FOREIGN EXCHANGE

	Three Months Ended			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2024**	June 30, 2023	March 31, 2024	**June 30, 2024**	June 30, 2023
Realized loss (gain)	**(0.5)**	0.3	2.0	**1.5**	0.5
Unrealized loss (gain) - Senior Notes	**6.9**	(13.7)	14.9	**21.8**	(15.6)
Unrealized loss (gain) - Credit Facility	**(20.6)**	(17.4)	50.1	**29.5**	(43.1)
Unrealized (gain) loss - cross-currency swaps	**20.9**	18.2	(49.5)	**(28.6)**	40.5
Unrealized loss (gain) - other	**0.2**	0.4	2.9	**3.1**	(0.4)
Foreign Exchange loss (gain)	**6.9**	(12.2)	20.4	**27.3**	(18.1)

Foreign exchange for the three months ended June 30, 2024 resulted in a loss of $6.9 million compared to a gain of $12.2 million and a loss of $20.4 million for the three month periods ending June 30, 2023 and March 31, 2024, respectively. For the six months ended June 30, 2024, foreign exchange resulted in a loss of $27.3 million compared to a gain of $18.1 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 Thermal includes the development and production of bitumen in the Cold Lake region of Northern Alberta.

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

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

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

For the Three Months Ended ($ millions, unless otherwise indicated)	Cold Lake Thermal Segment			Lloydminster Heavy Oil Segment			Montney Segment			Corporate			Consolidated		
	Jun 30, 2024	Jun 30, 2023	Mar 31, 2024	**Jun 30, 2024**	Jun 30, 2023	Mar 31, 2024	**Jun 30, 2024**	Jun 30, 2023	Mar 31, 2024	**Jun 30, 2024**	Jun 30, 2023	Mar 31, 2024	**Jun 30, 2024**	Jun 30, 2023	Mar 31, 2024
Production volumes															
Bitumen (bbl/d)	**59,581**	53,825	60,150	**—**	—	—	**—**	—	—	**—**	—	—	**59,581**	53,825	60,150
Heavy oil (bbl/d)	**—**	4	—	**51,111**	53,466	51,835	**—**	—	—	**—**	—	—	**51,111**	53,470	51,835
Condensate and light oil (bbl/d)	**—**	—	—	**26**	48	46	**20,094**	10,552	19,233	**—**	—	—	**20,120**	10,600	19,279
Other NGLs (bbl/d)	**—**	—	—	**2**	1	2	**11,424**	7,779	11,736	**—**	—	—	**11,426**	7,780	11,738
Natural gas (mcf/d)	**—**	—	—	**1,231**	1,025	1,254	**235,939**	107,587	251,466	**—**	—	—	**237,170**	108,612	252,720
Production volumes (boe/d)	**59,581**	53,829	60,150	**51,344**	53,687	52,092	**70,841**	36,262	72,880	**—**	—	—	**181,766**	143,778	185,122
Sales volumes (boe/d)	**59,333**	53,892	60,422	**55,667**	53,083	49,560	**70,841**	36,264	72,880	**—**	—	—	**185,841**	143,239	182,862
Segment revenues															
Oil and natural gas sales	**703.2**	547.9	623.8	**527.9**	435.2	417.0	**241.2**	129.4	258.0	**—**	0.3	—	**1,472.3**	1,112.8	1,298.8
Sales of purchased products	**5.8**	5.4	1.0	**—**	2.4	—	**—**	—	—	**7.2**	6.2	1.0	**13.0**	14.0	2.0
Blending costs	**(245.0)**	(208.3)	(251.8)	**(42.4)**	(41.5)	(42.8)	**—**	—	—	**—**	—	—	**(287.4)**	(249.8)	(294.6)
Purchased product	**(5.8)**	(5.7)	(1.0)	**—**	(2.4)	—	**—**	—	—	**(7.2)**	(6.5)	(1.0)	**(13.0)**	(14.6)	(2.0)
Oil and natural gas sales, net of blending[1]	**458.2**	339.3	372.0	**485.5**	393.7	374.2	**241.2**	129.4	258.0	**—**	—	—	**1,184.9**	862.4	1,004.2
Segment expenses															
Royalties	**120.9**	66.5	57.1	**47.3**	35.4	42.8	**25.8**	4.3	26.3	**—**	—	—	**194.0**	106.2	126.2
Production and operating – Energy[1]	**34.8**	49.7	43.8	**27.6**	29.1	33.8	**2.5**	0.9	1.2	**—**	—		**64.9**	79.7	78.8
Production and operating – Non-energy[1]	**51.7**	43.7	48.0	**58.8**	50.8	45.5	**39.0**	16.4	41.9	**—**	—	—	**149.5**	110.9	135.4
Transportation and processing	**22.1**	18.7	21.6	**76.2**	66.7	65.2	**50.9**	19.4	56.6	**—**	—	—	**149.2**	104.8	143.4
Field Operating Income[1]	**228.7**	160.7	201.5	**275.6**	211.7	186.9	**123.0**	88.4	132.0	**—**	—	—	**627.3**	460.8	520.4
Depletion, depreciation and amortization	**42.3**	36.9	42.9	**111.0**	107.6	99.1	**71.9**	22.7	76.0	**3.9**	3.5	3.8	**229.1**	170.7	221.8
Field Operating Earnings[1]	**186.4**	123.8	158.6	**164.6**	104.1	87.8	**51.1**	65.7	56.0	**(3.9)**	(3.5)	(3.8)	**398.2**	290.1	298.6
General and administrative	**—**	—	—	**—**	—	—	**—**	—	—	**25.2**	20.8	22.0	**25.2**	20.8	22.0
Other loss (income)	**—**	—	—	**—**	—	—	**—**	—	—	**0.1**	(0.2)	(0.1)	**0.1**	(0.2)	(0.1)
Interest expense	**—**	—	—	**—**	—	—	**—**	—	—	**43.7**	50.3	45.4	**43.7**	50.3	45.4
Finance costs	**—**	—	—	**—**	—	—	**—**	—	—	**23.1**	17.8	22.3	**23.1**	17.8	22.3
Operating Earnings[1]													**306.1**	201.4	209.0
(Gain) loss on risk management contracts - realized	**—**	—	—	**—**	—	—	**—**	—	—	**11.4**	0.4	(4.5)	**11.4**	0.4	(4.5)
Loss (gain) on risk management contracts - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**(13.5)**	(142.5)	44.2	**(13.5)**	(142.5)	44.2
Foreign exchange loss (gain) - realized	**—**	—	—	**—**	—	—	**—**	—	—	**(0.5)**	0.3	2.0	**(0.5)**	0.3	2.0
Foreign exchange loss (gain) - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**7.4**	(12.5)	18.4	**7.4**	(12.5)	18.4
Transaction related costs (recoveries)	**—**	—	—	**—**	—	—	**—**	—	—	**0.3**	0.4	0.1	**0.3**	0.4	0.1
Unrealized loss (gain) on Sable remediation fund	**—**	—	—	**—**	—	—	**—**	—	—	**—**	0.1	0.1	**—**	0.1	0.1
Deferred tax expense	**—**	—	—	**—**	—	—	**—**	—	—	**73.8**	81.1	48.1	**73.8**	81.1	48.1
Income and comprehensive income													**227.2**	274.1	100.6

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

For the Three Months Ended ($/boe)	Cold Lake Thermal Segment			Lloydminster Heavy Oil Segment			Montney Segment			Corporate			Consolidated		
	Jun 30, 2024	Jun 30, 2023	Mar 31, 2024	**Jun 30, 2024**	Jun 30, 2023	Mar 31, 2024	**Jun 30, 2024**	Jun 30, 2023	Mar 31, 2024	**Jun 30, 2024**	Jun 30, 2023	Mar 31, 2024	**Jun 30, 2024**	Jun 30, 2023	Mar 31, 2024
Segment revenues															
Oil and natural gas sales	**91.46**	78.97	77.80	**98.15**	84.15	85.78	**37.42**	39.22	38.90	**—**	0.05	—	**75.45**	72.23	66.57
Sales of purchased products	**1.08**	—	0.18	**—**	—	—	**—**	—	—	**0.43**	1.07	0.06	**0.77**	1.07	0.12
Blending costs	**(6.64)**	(9.78)	(10.14)	**(2.31)**	(2.65)	(2.81)	**—**	—	—	**—**	—	—	**(5.39)**	(6.02)	(6.22)
Purchased product	**(1.07)**	—	(0.18)	**—**	—	—	**—**	—	—	**(0.43)**	(1.12)	(0.06)	**(0.77)**	(1.12)	(0.12)
Oil and natural gas sales, net of blending[(1)]	**84.83**	69.19	67.66	**95.84**	81.50	82.97	**37.42**	39.22	38.90	**—**	—	—	**70.06**	66.16	60.35
Segment expenses															
Royalties	**22.39**	13.57	10.38	**9.34**	7.33	9.49	**4.00**	1.30	3.97	**—**	—	—	**11.47**	8.15	7.58
Production and operating – Energy[(1)]	**6.45**	9.86	7.97	**5.45**	6.02	7.49	**0.39**	0.28	0.18	**—**	—	—	**3.84**	6.11	4.74
Production and operating – Non-energy[(1)]	**9.58**	9.17	8.73	**11.61**	10.52	10.09	**6.05**	4.98	6.32	**—**	—	—	**8.84**	8.51	8.14
Transportation and processing	**4.09**	3.80	3.93	**15.04**	13.82	14.46	**7.90**	5.88	8.53	**—**	—	—	**8.82**	8.04	8.62
Field Operating Netback[(1)]	**42.32**	32.79	36.65	**54.40**	43.81	41.44	**19.08**	26.78	19.90	**—**	—	—	**37.09**	35.35	31.27
Depletion, depreciation and amortization	**7.83**	7.53	7.80	**21.91**	22.28	21.97	**11.15**	6.89	11.46	**0.23**	0.27	0.23	**13.55**	13.10	13.33
Field Operating Earnings Netback[(1)]	**34.49**	25.26	28.84	**32.49**	21.53	19.46	**7.93**	19.89	8.44	**(0.23)**	(0.27)	(0.23)	**23.54**	22.25	17.94
General and administrative	**—**	—	—	**—**	—	—	**—**	—	—	**1.49**	1.59	1.32	**1.49**	1.59	1.32
Other (income) expense	**—**	—	—	**—**	—	—	**—**	—	—	**0.01**	(0.01)	(0.01)	**0.01**	(0.01)	(0.01)
Interest expense	**—**	—	—	**—**	—	—	**—**	—	—	**2.58**	3.86	2.73	**2.58**	3.86	2.73
Finance costs	**—**	—	—	**—**	—	—	**—**	—	—	**1.37**	1.36	1.34	**1.37**	1.36	1.34
Operating Earnings[(1)]													**18.09**	15.45	12.56
Effective royalty rate (%)[(1)]	**26.4**	19.6	15.3	**9.7**	9.0	11.4	**10.7**	3.3	10.2				**16.4**	12.3	12.6

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

For the Six Months Ended ($ millions, unless otherwise indicated)	Cold Lake Thermal Segment		Lloydminster Heavy Oil Segment		Montney Segment		Corporate		Consolidated	
	June 30, 2024	June 30, 2023	**June 30, 2024**	June 30, 2023	**June 30, 2024**	June 30, 2023	**June 30, 2024**	June 30, 2023	**June 30, 2024**	June 30, 2023
Production volumes										
Bitumen (bbl/d)	**59,865**	52,469	**—**	—	**—**	—	**—**	—	**59,865**	52,469
Heavy oil (bbl/d)	**—**	2	**51,473**	55,444	**—**	—	**—**	—	**51,473**	55,446
Condensate and light oil (bbl/d)	**—**	—	**37**	46	**19,663**	9,295	**—**	—	**19,700**	9,341
Other NGLs (bbl/d)	**—**	—	**2**	2	**11,580**	8,137	**—**	—	**11,582**	8,139
Natural gas (mcf/d)	**—**	—	**1,242**	968	**243,703**	110,474	**—**	—	**244,945**	111,442
Production volumes (boe/d)	**59,865**	52,471	**51,719**	55,653	**71,860**	35,844	**—**	—	**183,444**	143,968
Sales volumes (boe/d)	**59,877**	52,521	**52,614**	56,682	**71,860**	35,845	**—**	—	**184,351**	145,048
Segment revenues										
Oil and natural gas sales	**1,327.0**	1,016.4	**944.9**	884.6	**499.2**	258.4	**—**	1.1	**2,771.1**	2,160.5
Sales of purchased product	**6.8**	8.7	**—**	5.1	**—**	—	**8.2**	14.0	**15.0**	27.8
Blending costs	**(496.8)**	(442.9)	**(85.2)**	(92.1)	**—**	—	**—**	—	**(582.0)**	(535.0)
Purchased product	**(6.8)**	(9.2)	**—**	(5.1)	**—**		**(8.2)**	(15.1)	**(15.0)**	(29.4)
Oil and natural gas sales, net of blending[(1)]	**830.2**	573.0	**859.7**	792.5	**499.2**	258.4	**—**	—	**2,189.1**	1,623.9
Segment expenses										
Royalties	**178.0**	115.4	**90.1**	78.3	**52.1**	25.6	**—**	—	**320.2**	219.3
Production and operating – Energy[(1)]	**78.6**	104.9	**61.4**	61.7	**3.7**	1.8	**—**	—	**143.7**	168.4
Production and operating – Non-energy[(1)]	**99.7**	88.0	**104.3**	108.1	**80.9**	30.7	**—**	—	**284.9**	226.8
Transportation and processing	**43.7**	37.7	**141.4**	156.4	**107.5**	38.6	**—**	—	**292.6**	232.7
Field Operating Income[(1)]	**430.2**	227.0	**462.5**	388.0	**255.0**	161.7	**—**	—	**1,147.7**	776.7
Depletion, depreciation and amortization	**85.2**	66.8	**210.1**	214.9	**147.9**	45.4	**7.7**	6.7	**450.9**	333.8
Field Operating Earnings[(1)]	**345.0**	160.2	**252.4**	173.1	**107.1**	116.3	**(7.7)**	(6.7)	**696.8**	442.9
General and administrative	**—**	—	**—**	—	**—**	—	**47.2**	46.7	**47.2**	46.7
Other income	**—**	—	**—**	—	**—**	—	**—**	(0.2)	**—**	(0.2)
Interest expense	**—**	—	**—**	—	**—**	—	**89.1**	104.4	**89.1**	104.4
Finance costs	**—**	—	**—**	—	**—**	—	**45.4**	35.6	**45.4**	35.6
Current income tax (recovery)	**—**	—	**—**	—	**—**	—	**—**	(46.9)	**—**	(46.9)
Operating Earnings[(1)]									**515.1**	303.3
Loss on risk management contracts - realized	**—**	—	**—**	—	**—**	—	**6.9**	5.8	**6.9**	5.8
(Gain) on risk management contracts - unrealized	**—**	—	**—**	—	**—**	—	**30.7**	(212.1)	**30.7**	(212.1)
Foreign exchange (gain) - realized	**—**	—	**—**	—	**—**	—	**1.5**	0.5	**1.5**	0.5
Foreign exchange (gain) loss - unrealized	**—**	—	**—**	—	**—**	—	**25.8**	(18.6)	**25.8**	(18.6)
Transaction related costs	**—**	—	**—**	—	**—**	—	**0.4**	1.6	**0.4**	1.6
Unrealized (gain) loss on Sable remediation fund	**—**	—	**—**	—	**—**	—	**0.1**	(0.1)	**0.1**	(0.1)
Deferred tax expense (recovery)	**—**	—	**—**	—	**—**	—	**121.9**	161.6	**121.9**	161.6
Income and comprehensive income									**327.8**	364.6

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

For the Six Months Ended ($/boe)	Cold Lake Thermal Segment June 30, 2024	Cold Lake Thermal Segment June 30, 2023	Lloydminster Heavy Oil Segment June 30, 2024	Lloydminster Heavy Oil Segment June 30, 2023	Montney Segment June 30, 2024	Montney Segment June 30, 2023	Corporate June 30, 2024	Corporate June 30, 2023	Consolidated June 30, 2024	Consolidated June 30, 2023
Segment revenues										
Oil and natural gas sales	**84.49**	74.47	**92.28**	80.67	**38.17**	39.83	**—**	0.06	**71.01**	69.40
Sales of purchased products	**0.62**	—	**—**	—	**—**	—	**0.24**	1.06	**0.45**	1.06
Blending costs	**(8.32)**	(14.19)	**(2.50)**	(3.43)	**—**	—	**—**	—	**(5.77)**	(7.55)
Purchased product	**(0.62)**	—	**—**	—	**—**	—	**(0.24)**	(1.12)	**(0.45)**	(1.12)
Oil and natural gas sales, net of blending[1]	**76.17**	60.28	**89.78**	77.24	**38.17**	39.83	**—**	—	**65.24**	61.79
Segment expenses										
Royalties	**16.34**	12.14	**9.41**	7.63	**3.98**	3.95	**—**	—	**9.54**	8.35
Production and operating – Energy[1]	**7.21**	10.90	**6.41**	6.01	**0.28**	0.28	**—**	—	**4.28**	6.41
Production and operating – Non-energy[1]	**9.14**	9.39	**10.89**	10.54	**6.19**	4.73	**—**	—	**8.49**	8.64
Transportation and processing	**4.00**	3.97	**14.77**	15.25	**8.22**	5.95	**—**	—	**8.72**	8.86
Field Operating Netback[1]	**39.48**	23.88	**48.30**	37.81	**19.50**	24.92	**—**	—	**34.21**	29.53
Depletion, depreciation and amortization	**7.82**	7.03	**21.94**	20.95	**11.31**	7.00	**0.23**	0.25	**13.44**	12.71
Field Operating Earnings Netback[1]	**31.66**	16.85	**26.36**	16.86	**8.19**	17.92	**(0.23)**	(0.25)	**20.77**	16.82
General and administrative	**—**	—	**—**	—	**—**	—	**1.40**	1.78	**1.40**	1.78
Other income	**—**	—	**—**	—	**—**	—	**—**	(0.01)	**—**	(0.01)
Interest expense	**—**	—	**—**	—	**—**	—	**2.66**	3.98	**2.66**	3.98
Finance costs	**—**	—	**—**	—	**—**	—	**1.35**	1.35	**1.35**	1.35
Current income tax (recovery)	**—**	—	**—**	—	**—**	—	**—**	(1.79)	**—**	(1.79)
Operating Earnings[1]									**15.36**	11.51
Effective royalty rate (%)[1]	**21.4**	20.1	**10.5**	9.9	**10.4**	9.9			**14.6**	13.5

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

Cold Lake Thermal

Production at the Cold Lake Thermal segment for the three and six months ended June 30, 2024, increased to 59,581 boe per day and 59,865 boe per day, respectively, from 53,829 boe per day and 52,471 boe per day in the same periods of 2023. These increases are primarily due to production growth as a result of the capital program at the Company's Lindbergh, Tucker and Orion properties.

Oil and natural gas sales, net of blending, increased to $458.2 million ($84.83 per boe) during the three months ended June 30, 2024 compared to $339.3 million ($69.19 per boe) for the same quarter of 2023. During the six months ended June 30, 2024 oil and natural gas sales, net of blending, increased to $830.2 million ($76.17 per boe) compared to $573.0 million ($60.28 per boe) for the same quarter of 2023. These increases are primarily due to higher sales volumes, stronger benchmark pricing, and lower per barrel blending costs.

The effective royalty rate for the three and six months ended June 30, 2024 increased to 26.4% and 21.4%, respectively, from 19.6% and 20.1% in the same periods of 2023. These increases were primarily the result of increased benchmark commodity prices in the respective periods.

Energy related production and operating expenses for the three and six months ended June 30, 2024 decreased to $34.8 million ($6.45 per boe) and $78.6 million ($7.21 per boe), respectively, from $49.7 million ($9.86 per boe) and $104.9 million ($10.90 per boe) in the same periods of of 2023. These decreases are primarily attributable to the lower price of natural gas and electricity in the first half of 2024, partially offset by an increase to the carbon tax price per tonne.

Non-energy related production and operating expenses for the three months ended June 30, 2024 increased to $51.7 million ($9.58 per boe) from $43.7 million ($9.17 per boe) for the same quarter of 2023. The increase was primarily due to increased chemical cost as a result of sulphur recovery units installed in the first quarter of 2024 becoming fully operational in the second quarter, an increase in production, and increases in surface maintenance and downhole maintenance costs.

For the six months ended June 30, 2024, non-energy related production and operating expenses increased to $99.7 million from $88.0 million in the same period of 2023. The increase was primarily due to increased sales volumes and an increase in chemical cost as a result of sulphur recovery units installed in the first quarter of 2024 becoming fully operational in the second quarter. The per boe decrease in non-energy related production to $9.14 per boe from $9.39 per boe is due to the increase in sales volumes in the period exceeding the relative increase in costs.

For the three and six months ended June 30, 2024, transportation and processing increased to $22.1 million and $43.7 million, respectively, from $18.7 million and $37.7 million in the same periods of 2023, primarily due to increased sales volumes. For the three months ended June 30, 2024 transportation and processing increased to $4.09 per boe from $3.80 per boe in the same quarter of 2023 primarily due to increased contracted transportation rates. For the six months ended June 30, 2024 transportation and processing per boe remained consistent with the prior year; transportation rate increases were offset by cost savings in the current period from make-up rights related to take-or-pay arrangements and fees incurred on take-or-pay arrangements in the comparative period of 2023.

Lloydminster Heavy Oil

Production from the Lloydminster Heavy Oil segment for the three and six months ended June 30, 2024, decreased to 51,344 boe per day and 51,719 boe per day, respectively, from 53,687 boe per day and 55,653 boe per day in the same periods of 2023. These decreases were primarily due to lower production volumes from Saskatchewan thermal properties.

Sales volumes increased to 55,667 boe per day for the three months ended June 30, 2024, from 49,560 boe per day in the previous quarter of 2024, and from 53,083 boe per day in the same quarter of 2023. These increases are primarily attributable to the sale of inventory volumes throughout the second quarter of 2024 due to the completion of the expanded unit train offloading facility in the US Gulf Coast, which became fully operational in the quarter.

Sales volumes decreased to 52,614 boe per day for the six months ended June 30, 2024 from 56,682 boe per day in the same period of 2023. This decrease is primarily due to lower production volumes from Saskatchewan thermal properties.

Oil and natural gas sales, net of blending, increased to $485.5 million ($95.84 per boe) during the three months ended June 30, 2024 compared to $393.7 million ($81.50 per boe) for the same period of 2023. The increase is primarily due to higher sales volumes and stronger benchmark pricing.

Oil and natural gas sales, net of blending, increased to $859.7 million ($89.78 per boe) during the six months ended June 30, 2024 compared to $792.5 million ($77.24 per boe) for the same period of 2023. The increase is primarily due to higher benchmark commodity prices partially offset by lower sales volumes.

The effective royalty rate for the three and six months ended June 30, 2024 increased to 9.7% and 10.5%, respectively, from 9.0% and 9.9% in the same periods of 2023. These increases were primarily the result of increased benchmark commodity prices in the respective periods.

Energy related production and operating expenses for the three and six months ended June 30, 2024 decreased to $27.6 million ($5.45 per boe) and $61.4 million ($6.41 per boe), respectively, from $29.1 million ($6.02 per boe) and $61.7 million ($6.01 per boe) for the same periods in 2023. The decreases are primarily attributable to the lower price of natural gas and electricity in the first half of 2024, partially offset by an increase to the carbon tax price per tonne.

Non-energy related production and operating expenses for the three months ended June 30, 2024 increased to $58.8 million ($11.61 per boe) from $50.8 million ($10.52 per boe) in the same period of 2023. The increase is primarily due to higher sales volumes during the current period, partially offset by a decrease in downhole maintenance costs. The per boe increase in non-energy related production is due to the relative increase in costs exceeding the increase in sales volumes in the period.

Non-energy related production and operating expenses for the six months ended June 30, 2024 decreased to $104.3 million ($10.89 per boe) from $108.1 million ($10.54 per boe) in the same period of 2023. The decrease is primarily due to a decrease in sales volumes, lower chemical costs and lower downhole maintenance costs, partially offset by increased labour costs.

For the three months ended June 30, 2024, transportation and processing increased to $76.2 million ($15.04 per boe) from $66.7 million ($13.82 per boe) in the same quarter of 2023. The increase is primarily due to higher sales volumes that were transported by rail which have a higher per boe cost. For the six months ended June 30, 2024, transportation and processing costs decreased to $141.4 million ($14.77 per boe) from $156.4 million ($15.25 per boe) in the same period of 2023. The decrease is primarily due to lower sales volumes and a lower proportion of sales that were transported by rail.

Montney

Production at the Company's Montney segment for the three and six months ended June 30, 2024 increased to 70,841 boe per day and 71,860 boe per day, respectively, from 36,262 boe per day and 35,844 boe per day in the same periods of 2023. The increases were primarily due to production from the properties acquired through the Pipestone Acquisition, which was completed in the fourth quarter of 2023. Production attributable to the acquired properties contributed 30,746 boe per day and 32,375 boe per day, respectively, for the three and six months ended June 30, 2024.

Oil and natural gas sales for the three and six months ended June 30, 2024 increased to $241.2 million ($37.42 per boe) and $499.2 million ($38.17 per boe), respectively, from $129.4 million ($39.22 per boe) and $258.4 million ($39.83 per boe) in the same periods of 2023. These increases were primarily due to increased volumes added through the Pipestone Acquisition and higher benchmark commodity prices on condensate and light oil and other NGL sales. These increases were partially offset by a decrease in AECO benchmark commodity prices on natural gas sales which is the primary cause of the decrease observed on a per boe basis.

For the three months ended June 30, 2024, royalties as a percentage of sales increased to 10.7% from 3.3% in the same quarter of 2023. The increase was primarily the result of increased condensate benchmark pricing coupled with a larger favorable gas cost allowance credit in the comparative period. For the six months ended June 30, 2024, royalties as a percentage of sales increased to 10.4% from 9.9% in the same period of 2023 primarily due to a larger favourable gas cost allowance credit in the comparative period.

Non-energy related production and operating expenses for the three and six months ended June 30, 2024 increased to $39.0 million ($6.05 per boe) and $80.9 million ($6.19 per boe), respectively, from $16.4 million ($4.98 per boe) and $30.7 million ($4.73 per boe) in the same periods of 2023. The increases are primarily due to associated fees on gas production for properties acquired through the Pipestone Acquisition.

Transportation and processing costs increased to $50.9 million ($7.90 per boe) for the three months ended June 30, 2024 from $19.4 million ($5.88 per boe) in the same quarter of 2023. For the six months ended June 30, 2024, transportation and processing costs increased to $107.5 million ($8.22 per boe) from $38.6 million ($5.95 per boe) in the same period of 2023. These increases are primarily due to increased volumes added through the Pipestone Acquisition. The increases on a per boe basis are due to properties 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 Facility

Covenant-Based Revolving Credit Facility

As at June 30, 2024, the Company had a covenant-based revolving credit facility of $2.5 billion (December 31, 2023 - $2.3 billion) with a syndicate of Canadian, U.S. and international financial institutions (the "**Revolving Credit Facility**").

The Revolving Credit Facility has a maturity date of March 28, 2028, provided that the maturity date will be May 1, 2026 if the Senior Notes (as defined below) remain outstanding and have not been refinanced or legally defeased at such date. There are no mandatory payments on the Revolving Credit Facility. Borrowings under the Revolving Credit Facility may be drawn and repaid from time to time by the Company in Canadian or U.S. dollars. In addition, the covenant-based Revolving Credit Facility is not a borrowing base facility and does not require annual or semi-annual reviews.

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

As at June 30, 2024, the Company had letters of credit outstanding under the Revolving Credit Facility of $2.9 million (December 31, 2023 - $10.6 million).

Foreign Exchange Risk Management on U.S. Denominated Debt

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

Foreign currency risk associated with these borrowings is 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 June 30, 2024 the cross-currency swap liability was $11.0 million (December 31, 2023 – $39.6 million) and total debt includes an unrealized gain of $11.8 million (December 31, 2023 – $41.3 million) related to U.S. borrowings on the Revolving Credit Facility. Unrealized gains or losses on U.S. borrowings and offsetting unrealized gains or losses on cross-currency interest swap contracts are included in foreign exchange gains in the interim financial statements.

As at June 30, 2024, the Company had the following cross-currency interest rate swap contracts outstanding totaling.

Notional (US$)	Maturity Date	Contract Price
1,297.6 million	July 15, 2024	CAD/USD 1.3770

Financial Covenants

As at June 30, 2024, the Revolving Credit Facility had three financial covenants which are calculated quarterly (as set out below) in accordance with the credit agreement governing the Revolving Credit Facility (the "**Credit Agreement**").

(i) Total Debt to Adjusted EBITDA Ratio – All debt excluding the Financing Agreement (see Note 5 of the interim financial statements), capital leases and letters of credit constituting debt ("**Total Debt**"), each as defined in the Credit Agreement shall not exceed 4.0 times trailing 12-month net income before non-cash items, income taxes, interest expense and extraordinary and non-recurring losses, adjusted for material acquisitions or dispositions as if they occurred on the first day of the calculation period ("**Adjusted EBITDA**"). For the purposes of Adjusted EBITDA, lease payments are deducted from the calculation if a lease would have been considered an operating lease before the adoption of IFRS 16. Total Debt may include the value of the Company's undiscounted inactive abandonment and reclamation obligations for a material jurisdiction if the liability management ratio in that jurisdiction falls below the minimum maintenance level required under the Credit Agreement (1.0 in British Columbia and 2.0 in all other material jurisdictions). Liability management ratios are calculated by provincial regulators based on deemed asset and deemed liability values determined by the respective regulator, other than for British Columbia, which is calculated by the Company based on past practice of the BC Oil and Gas Commission.

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

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

As at June 30, 2024, the Company was in compliance with such financial covenants, which are summarized in the following table.

As at	**June 30, 2024**
Total Debt to Adjusted EBITDA Ratio (≤ 4.00)[1]	**1.17**
Senior Debt to Adjusted EBITDA Ratio (≤ 3.50)[1]	**0.85**
Interest Coverage Ratio (≥ 3.50)[1]	**10.01**

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

Senior Notes

As at June 30, 2024, Strathcona had $684.0 million (December 31, 2023 - $662.2 million) of senior unsecured notes outstanding, with an aggregate principal amount of US$500.0 million, due August 1, 2026 (the “**Senior Notes**”). The Senior Notes bear interest at 6.875% per annum, payable semi-annually in arrears on February 1 and August 1 of each year. The Senior Notes are redeemable at Strathcona’s option, in whole or in part, at the following redemption prices.

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

The Senior Notes have no financial maintenance covenants.

Demand Letter of Credit Facility

As at June 30, 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 June 30, 2024, the Company had letters of credit in the amount of $65.4 million (December 31, 2023 - $69.0 million) outstanding under the LC Facility.

CAPITAL MANAGEMENT AND LIQUIDITY

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

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

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

As at	**June 30, 2024**	December 31, 2023
Credit capacity	**2,500.0**	2,300.0
Revolving Credit Facility debt at period end exchange rate	**(1,787.4)**	(2,036.3)
Unrealized loss (gain) on U.S. borrowings	**(11.8)**	(41.3)
Letters of credit outstanding	**(2.9)**	(10.6)
Availability	**697.9**	211.8

The Company carries a working capital deficiency as part of its current capital structure. As at June 30, 2024, the working capital deficiency was $339.1 million (December 31, 2023 - $415.3 million). Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Company to remedy its working capital deficiency, meet its current and future obligations, to make scheduled interest payments, to fund planned capital expenditures and to fund the other needs of the business for at least the next 12 months. However, no assurance can be given that this will be the case or that future sources of capital will not be necessary. The Company's cash flow and the development of projects are dependent on factors discussed in the "Risk Factors" section of the Annual Information Form for the year ended December 31, 2023.

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

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

DECOMMISSIONING LIABILITY

At June 30, 2024, Strathcona's discounted decommissioning provision balance was $352.8 million (December 31, 2023 - $351.3 million) for future abandonment and reclamation of the Company's oil and natural gas properties. During the six months ended June 30, 2024, the Company incurred $14.5 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 June 30, 2024.

	Total	<1 year	1-3 years	4-5 years	> 5 years
Revolving Credit Facility(1)	**1,799.2**	—	1,799.2	—	—
Senior Notes(2)	**801.5**	47.0	754.5	—	—
Accounts payable and accrued liabilities	**772.4**	772.4	—	—	—
Risk management contract liability	**158.1**	8.9	149.2	—	—
Lease and other obligations(3)	**584.1**	84.0	157.9	107.4	234.8
Total	**4,115.3**	912.3	2,860.8	107.4	234.8

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

(2) Amounts represent repayment of the Senior Notes ($684.0 million) and associated interest payments ($117.5 million) based on the foreign exchange rate in effect on June 30, 2024.

(3) Amounts relate to undiscounted payments for lease and other obligations. The estimation of future cash payments related to other obligations are subject to forecast lending rates and timing of exercise of the Repurchase Option. As at June 30, 2024, the Repurchase Option on the Financing Arrangement was estimated to be exercised on January 1, 2029. See Note 5 of the interim financial statements.

On July 15, 2024, Strathcona exercised its option to terminate the then existing asset-backed financing arrangement for consideration of $157.6 million.

On August 9, 2024, Strathcona entered into a new asset-backed financing agreement backed by its interest in certain processing facility assets for $112.4 million, which consideration was provided by way of the lender's concurrent assumption of certain outstanding premiums on hedging transactions from Strathcona.

As at June 30, 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	**2,326.4**	298.9	569.7	466.6	991.2
Capital commitments	**179.4**	169.3	10.1	—	—
Other	**20.2**	6.8	11.0	2.4	—
Total	**2,526.0**	475.0	590.8	469.0	991.2

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

SHARE CAPITAL

The authorized capital of the Company consists of an unlimited number of common shares and an unlimited number of preferred shares. No preferred shares have been issued by the Company as at June 30, 2024 (December 31, 2023 – nil).

The following table summarizes the number of shares outstanding as at August 13, 2024:

Share Class	Shares Outstanding at August 13, 2024
Preferred shares	nil
Common shares	214,235,608
Balance outstanding	**214,235,608**

The Company had no outstanding securities which are convertible into common shares or preferred shares as at August 13, 2024.

SUMMARY OF QUARTERLY RESULTS

	2024		2023				2022	
($ millions, unless otherwise indicated)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Operating results (boe/d)								
Average production volumes	**181,766**	185,122	186,064	147,461	143,778	144,160	143,371	119,829
Average sales volumes	**185,841**	182,862	184,360	148,874	143,239	146,877	141,595	119,992
Financial Results								
Oil and natural gas sales	**1,472.3**	1,298.8	1,287.6	1,300.2	1,112.8	1,047.7	1,124.9	1,112.6
Net Income (loss)	**227.2**	100.6	263.7	(41.1)	274.1	90.5	62.2	606.3
Net income (loss) per share	**1.06**	0.47	1.23	(0.02)	0.13	0.04	0.03	0.28
Cash flow from operating activities	**519.7**	408.8	570.0	430.5	343.1	181.1	482.2	373.5
Operating Earnings(1)	**306.1**	209.0	202.1	289.9	201.4	101.9	169.4	284.3
Funds from Operations(1)	**547.6**	455.6	470.8	425.3	389.2	276.9	308.1	322.9
Free Cash Flow(1)	**247.3**	157.9	150.8	158.0	152.6	36.1	75.1	157.1
Field Operating Income(1)	**627.3**	520.4	527.4	549.6	460.8	315.9	395.1	432.4
Field Operating Netback ($/boe)(1)	**37.09**	31.27	31.09	40.13	35.35	23.82	30.33	39.16
Capital expenditures	**298.0**	286.1	307.8	260.2	231.7	228.7	228.5	157.5
Decommissioning expenditures	**2.9**	11.6	13.8	7.1	4.9	12.1	4.5	8.3
Total assets	**10,670.9**	10,597.8	10,496.9	9,588.9	9,451.2	9,289.5	9,164.5	9,416.3
Debt	**2,435.6**	2,642.5	2,665.0	2,787.6	2,898.2	3,041.7	3,044.1	3,545.9
Total equity	**5,654.9**	5,427.7	5,327.1	4,526.4	4,567.5	4,292.7	4,202.2	4,088.9
Common shares outstanding, end of period	**214.2**	214.2	214.2	2,186.7	2,186.7	2,186.5	2,186.5	2,186.6

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

Over the past eight quarters, the Company's oil and natural gas sales have fluctuated due to the Pipestone Acquisition as described in Note 4 of the annual financial statements, volatility in the crude oil, condensate and natural gas benchmark prices, oil price differentials and changes in production. The Company's production has fluctuated due to acquisitions and dispositions, changes in its development capital spending levels and natural declines.

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

Capital expenditures and total assets have fluctuated throughout the past eight quarters due to changes in the Company's development capital spending levels which vary based on a number of factors, including the prevailing commodity price environment and the Pipestone Acquisition as described in Note 4 of the annual financial statements.

SPECIFIED FINANCIAL MEASURES

This MD&A makes reference to certain financial measures and ratios, including “Oil and natural gas sales, net of blending”, “Bitumen blend per bbl”, “Heavy oil, blended and raw per bbl”, “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”, “Field Operating Income”, “Field Operating Netback”, “Funds from Operations”, “Free Cash Flow”, “Operating Earnings”, “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 IFRS. Accordingly, the Company’s use of these terms may not be comparable to similarly defined measures presented by other companies. Management uses the terms “Field Operating Income”, “Field Operating Netback”, “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 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. 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 – Energy and 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			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2024**	June 30, 2023	March 31, 2024	**June 30, 2024**	June 30, 2023
Oil and natural gas sales	**1,472.3**	1,112.8	1,298.8	**2,771.1**	2,160.5
Sales of purchased products	**13.0**	14.0	2.0	**15.0**	27.8
Purchased product	**(13.0)**	(14.6)	(2.0)	**(15.0)**	(29.4)
Blending costs	**(287.4)**	(249.8)	(294.6)	**(582.0)**	(535.0)
Oil and natural gas sales, net of blending	**1,184.9**	862.4	1,004.2	**2,189.1**	1,623.9
Royalties	**194.0**	106.2	126.2	**320.2**	219.3
Production and operating	**214.4**	190.6	214.2	**428.6**	395.2
Transportation and processing	**149.2**	104.8	143.4	**292.6**	232.7
Field Operating Income	**627.3**	460.8	520.4	**1,147.7**	776.7
Depletion, depreciation and amortization	**229.1**	170.7	221.8	**450.9**	333.8
Field Operating Earnings	**398.2**	290.1	298.6	**696.8**	442.9
Field Operating Netback ($/boe)	**37.09**	35.35	31.27	**34.21**	29.53
Field Operating Earnings Netback ($/boe)	**23.54**	22.25	17.94	**20.77**	16.82

“**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			Six Months Ended	
($ millions, unless otherwise indicated)	**June 30, 2024**	June 30, 2023	March 31, 2024	**June 30, 2024**	June 30, 2023
Income and comprehensive income	**227.2**	274.1	100.6	**327.8**	364.6
(Gain) loss on risk management contracts	**(2.1)**	(142.1)	39.7	**37.6**	(206.3)
Foreign exchange loss (gain)	**6.9**	(12.2)	20.4	**27.3**	(18.1)
Transaction related costs	**0.3**	0.4	0.1	**0.4**	1.6
Unrealized loss (gain) on Sable remediation fund	**—**	0.1	0.1	**0.1**	(0.1)
Deferred tax expense	**73.8**	81.1	48.1	**121.9**	161.6
Operating Earnings	**306.1**	201.4	209.0	**515.1**	303.3
Depletion, depreciation and amortization	**229.1**	170.7	221.8	**450.9**	333.8
Finance costs	**23.1**	17.8	22.3	**45.4**	35.6
Decommissioning government grant	**0.2**	—	—	**0.2**	(0.3)
(Loss) gain on risk management contracts - realized	**(11.4)**	(0.4)	4.5	**(6.9)**	(5.8)
Foreign exchange gain (loss) - realized	**0.5**	(0.3)	(2.0)	**(1.5)**	(0.5)
Funds from Operations	**547.6**	389.2	455.6	**1,003.2**	666.1
Capital expenditures	**(297.4)**	(231.7)	(286.1)	**(583.5)**	(460.4)
Decommissioning costs	**(2.9)**	(4.9)	(11.6)	**(14.5)**	(16.7)
Free Cash Flow	**247.3**	152.6	157.9	**405.2**	189.0

Financial Covenant Calculations

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

($ millions, unless otherwise indicated)	As at June 30, 2024
Revolving Credit Facility	**1,787.4**
Unrealized loss on SOFR loans	**11.8**
Senior Debt	**1,799.2**
Senior Notes	**684.0**
Total Debt	**2,483.2**

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

($ millions, unless otherwise indicated)	Trailing 12-months ended June 30, 2024
Net income	**550.4**
Adjusted for	
Interest and finance costs	**276.0**
Unrealized gain on commodity contracts	**130.8**
Depletion, depreciation, amortization and impairment	**850.0**
Unrealized foreign exchange gain	**23.7**
Income tax expense	**256.5**
ARO government grants	**0.2**
IFRS 16 adjustment	**(44.5)**
EBITDA from Pipestone assets	**69.1**
Non-recurring losses	**2.6**
Adjusted EBITDA	**2,114.8**

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

($ millions, unless otherwise indicated)	Trailing 12-months ended June 30, 2024
Interest on debt	**190.9**
Other adjustments(1)	**20.3**
Interest Charges	**211.2**

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

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may 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 consolidated financial statements are discussed in note 2 of the consolidated financial statements for the year ended December 31, 2023.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Strathcona is required to comply with National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("**NI 52-109**"). The certification of interim filings for the interim period ended June 30, 2024 requires that Strathcona disclose in the interim MD&A any changes in Strathcona's Internal controls over financial reporting ("**ICFR**") that occurred during the period that have materially affected, or are reasonably likely to materially affect, Strathcona's ICFR. Strathcona confirms that no such changes were made to its ICFR during the three months ended June 30, 2024.

ADVISORIES REGARDING OIL & GAS INFORMATION

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

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

The Company's annual and quarterly average daily production volumes for 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			Six Months Ended	
	June 30, 2024	June 30, 2023	March 31, 2024	**June 30, 2024**	June 30, 2023
Cold Lake Thermal segment					
Heavy crude oil (bbl/d)	**—**	4	—	**—**	2
Light and medium crude oil (bbl/d)	**—**	—	—	**—**	—
Total crude oil (bbl/d)	**—**	4	—	**—**	2
Bitumen (bbl/d)	**59,581**	53,825	60,150	**59,865**	52,469
NGLs (bbl/d)	**—**	—	—	**—**	—
Total liquids (bbl/d)	**59,581**	53,829	60,150	**59,865**	52,471
Conventional natural gas (mcf/d)	**—**	—	—	**—**	—
Total (boe/d)	**59,581**	53,829	60,150	**59,865**	52,471
Lloydminster Heavy Oil segment					
Heavy crude oil (bbl/d)	**51,111**	53,466	51,835	**51,473**	55,444
Light and medium crude oil (bbl/d)	**26**	48	46	**37**	46
Total crude oil (bbl/d)	**51,137**	53,514	51,881	**51,510**	55,490
Bitumen (bbl/d)	**—**	—	—	**—**	—
NGLs (bbl/d)	**2**	1	2	**2**	2
Total liquids (bbl/d)	**51,139**	53,515	51,883	**51,512**	55,492
Conventional natural gas (mcf/d)	**1,231**	1,025	1,254	**1,242**	968
Total (boe/d)	**51,344**	53,687	52,092	**51,719**	55,653
Montney segment					
Heavy crude oil (bbl/d)	**—**	—	—	**—**	—
Light and medium crude oil (bbl/d)	**764**	624	505	**634**	651
Total crude oil (bbl/d)	**764**	624	505	**634**	651
Bitumen (bbl/d)	**—**	—	—	**—**	—
NGLs (bbl/d)	**30,754**	17,707	30,464	**30,609**	16,781
Total liquids (bbl/d)	**31,518**	18,331	30,969	**31,243**	17,432
Conventional natural gas (mcf/d)	**235,939**	107,587	251,466	**243,703**	110,474
Total (boe/d)	**70,841**	36,262	72,880	**71,860**	35,844
Consolidated					
Heavy crude oil (bbl/d)	**51,111**	53,470	51,835	**51,473**	55,446
Light and medium crude oil (bbl/d)	**790**	672	551	**671**	697
Total crude oil (bbl/d)	**51,901**	54,142	52,386	**52,144**	56,143
Bitumen (bbl/d)	**59,581**	53,825	60,150	**59,865**	52,469
NGLs (bbl/d)	**30,756**	17,708	30,466	**30,611**	16,783
Total liquids (bbl/d)	**142,238**	125,675	143,002	**142,620**	125,395
Conventional natural gas (mcf/d)	**237,170**	108,612	252,720	**244,945**	111,442
Total (boe/d)	**181,766**	143,778	185,122	**183,444**	143,968

FORWARD-LOOKING INFORMATION

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

The use of any of the words "expect", "anticipate", "estimate", "objective", "ongoing", "may", "will", "project", "believe", "depends", "could" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the generality of the foregoing, this MD&A contains forward-looking information pertaining to the following: the Company's business strategy and future plans; the Company's 2024 production and capital spending guidance; the declaration and payment of dividends; the Company's use of hedging arrangements; the Company's ability to meet current and future obligations, including making scheduled principal and interest payments, to fund planned capital expenditures and to fund the other needs of the business; future liquidity and financial capacity; anticipated proceeds from financial instruments, including commodity contracts; sources of funding for the Company's capital program and the terms of Strathcona's future contractual obligations, including its obligations under the Credit Agreement and Senior Notes and oil and natural gas prices and differentials; the arrangement between Strathcona and CGF; the construction, operation and funding of the CCS facilities; CGF's expected investment in the CCS facilities and Strathcona's repayment thereof, including the availability of the federal CCS investment tax credit and other grants; and targeted final investment decision date for Strathcona's first commercial CCS project.

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; 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, expectations regarding current and future carbon tax regime and regulations; and Strathcona's ability to obtain the federal CCS investment tax credit and other grants to fund Strathcona's portion of the investment under the arrangement with CGF. In addition, certain forward-looking information with respect to the Company's 2024 capital budget assumes commodity prices and exchange rates of: US$80 / bbl WTI, assuming a US$15.75 / bbl WCS-WTI differential, 0.73 USD-CAD and C$3.22 / mcf AECO. Management believes that its assumptions and expectations reflected in the forward-looking information contained herein are reasonable based on the information available on the date such information is provided and the process used to prepare the information. However, it cannot assure readers that these expectations will prove to be correct.

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

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 risks 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, 2023 and its Management's Discussion and Analysis for the year ended December 31, 2023, can be found at: www.sedarplus.ca and www.strathconaresources.com.