



**STRATHCONA**  
RESOURCES LTD

**MANAGEMENT'S DISCUSSION AND ANALYSIS  
FOR THE THREE MONTHS ENDED MARCH 31, 2026 AND 2025**

## MANAGEMENT'S DISCUSSION AND ANALYSIS

The following management's discussion and analysis ("**MD&A**") of the financial condition and results of operations for Strathcona Resources Ltd. (the "**Company**" or "**Strathcona**") is dated May 6, 2026 and should be read in conjunction with the Company's unaudited condensed consolidated interim financial statements (and related notes) as at and for the three months ended March 31, 2026 and 2025 (the "**interim financial statements**") and the Company's audited consolidated financial statements as at and for the years ended December 31, 2025 and 2024 (the "**annual financial statements**"). The interim financial statements have been prepared in accordance with IFRS® Accounting Standards (the "**Accounting Standards**") as issued by the International Accounting Standards Board, in Canadian dollars, except where indicated otherwise. The interim financial statements, annual financial statements and MD&A of Strathcona have been prepared by management, reviewed by the Audit Committee of the Company's Board of Directors and were approved by the Company's Board of Directors.

This MD&A contains forward-looking information; see "*Forward-Looking Information*" in this MD&A for further information. This MD&A also contains financial measures that do not have a standardized meaning under the Accounting Standards and may not be comparable to similar financial measures disclosed by other issuers; see "*Specified Financial Measures*" in 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, except when noted otherwise. All per unit figures are based on commodity sales volumes, net of blending. Sales volumes differ from production volumes resulting from changes in oil inventory.

## DESCRIPTION OF BUSINESS

Strathcona is a corporation that exists under, and is governed by, the provisions of the *Business Corporations Act* (Alberta). Strathcona's common shares are listed on the Toronto Stock Exchange under the trading symbol "SCR". Following the disposition of its Montney business through the Groundbirch Asset Sale and the Kakwa and Grande Prairie Asset Sales in 2025 (each as defined and described under "*Presentation of Continuing and Discontinued Operations*" in this MD&A), Strathcona is a Calgary-based pure play heavy oil producer engaged in the acquisition, exploration, development and production of petroleum and natural gas reserves with operations focused on thermal oil and enhanced oil recovery. Strathcona's crude oil property interests are principally located in Western Canada, in the provinces of Alberta and Saskatchewan.

At the date of this MD&A, approximately 66.6% of the Company's common shares, were owned by certain limited partnerships comprising Waterous Energy Fund (collectively, "**WEF**").

## PRESENTATION OF CONTINUING AND DISCONTINUED OPERATIONS

During the year ended December 31, 2025, the Company entered into three separate asset purchase and sale agreements to dispose of its Montney segment. The Montney segment represented a separate major line of business and geographical area of operations, therefore, its results have been classified as discontinued operations in accordance with IFRS 5 *Non-Current Assets Held for Sale and Discontinued Operations*.

### **Groundbirch Asset Sale**

On June 1, 2025, the Company completed the sale of assets located primarily in the Groundbirch area in Northeast British Columbia (the "**Groundbirch Asset Sale**") for aggregate proceeds of \$292 million, inclusive of closing adjustments, paid in common shares of Tourmaline Oil Corp. An associated gain on sale of assets of \$138 million was recognized on close of the transaction.

### **Kakwa and Grande Prairie Asset Sales**

On May 14, 2025, the Company entered into asset purchase and sale agreements pursuant to which the Company agreed to sell assets primarily located in the Kakwa and Grande Prairie areas in Northwest Alberta (the "**Kakwa and Grande Prairie Asset Sales**"). On July 2, 2025, the Company completed the Kakwa and Grande Prairie Asset Sales for total cash consideration of \$2,399 million, inclusive of closing adjustments. An associated gain on sale of assets of \$604 million was recognized on close of the transaction.

The financial results for the three months ended March 31, 2026 and 2025, are presented below to reconcile continuing and discontinued operations to total results. Total results is a non-GAAP measure, which does not have a standardized meaning under the Accounting Standards and may not be comparable to similar financial measures disclosed by other issuers. Total results is used by management of Strathcona to assess the historical financial performance of the total business and is not intended to be indicative of future results of the Company.

(\$ millions, unless otherwise indicated)	Three Months Ended March 31, 2026			Three Months Ended March 31, 2025 <sup>(1)</sup>		
	Continuing	Discontinued	Total	Continuing	Discontinued	Total
<b>Revenues and other income</b>						
Oil and natural gas sales	1,121	—	<b>1,121</b>	1,176	283	<b>1,459</b>
Sale of purchased products	4	—	<b>4</b>	7	—	<b>7</b>
Royalties	(142)	—	<b>(142)</b>	(112)	(26)	<b>(138)</b>
Oil and natural gas revenues	983	—	<b>983</b>	1,071	257	<b>1,328</b>
Loss on risk management contracts	(71)	—	<b>(71)</b>	(78)	—	<b>(78)</b>
Midstream revenue	9	—	<b>9</b>	—	—	<b>—</b>
Other income	—	—	<b>—</b>	1	—	<b>1</b>
	921	—	<b>921</b>	994	257	<b>1,251</b>
<b>Expenses</b>						
Purchased product	4	—	<b>4</b>	8	—	<b>8</b>
Blending costs	306	—	<b>306</b>	326	—	<b>326</b>
Production and operating	185	—	<b>185</b>	182	49	<b>231</b>
Transportation and processing	94	—	<b>94</b>	88	54	<b>142</b>
General and administrative	28	—	<b>28</b>	19	6	<b>25</b>
Interest	28	—	<b>28</b>	38	—	<b>38</b>
Transaction related costs	—	—	<b>—</b>	1	—	<b>1</b>
Finance costs	11	—	<b>11</b>	12	9	<b>21</b>
Depletion, depreciation and amortization	142	—	<b>142</b>	148	68	<b>216</b>
Foreign exchange loss (gain)	4	—	<b>4</b>	(1)	—	<b>(1)</b>
Change in decommissioning liabilities	13	—	<b>13</b>	—	—	<b>—</b>
Loss on contingent consideration	42	—	<b>42</b>	—	—	<b>—</b>
	857	—	<b>857</b>	821	186	<b>1,007</b>
Gain on marketable securities	—	—	<b>—</b>	23	—	<b>23</b>
<b>Income before income taxes</b>	64	—	<b>64</b>	196	71	<b>267</b>
Income tax expense	25	—	<b>25</b>	43	18	<b>61</b>
<b>Income and comprehensive income</b>	39	—	<b>39</b>	153	53	<b>206</b>

(1) Comparative period has been revised to reflect current period presentation.

The following table reconciles the total operating earnings.

(\$ millions, unless otherwise indicated)	Three Months Ended March 31, 2026			Three Months Ended March 31, 2025 <sup>(1)</sup>		
	Continuing	Discontinued	Total	Continuing	Discontinued	Total
<b>Revenues</b>						
Oil and natural gas sales	1,121	—	<b>1,121</b>	1,176	283	<b>1,459</b>
Sale of purchased product	4	—	<b>4</b>	7	—	<b>7</b>
Blending costs	(306)	—	<b>(306)</b>	(326)	—	<b>(326)</b>
Purchased product	(4)	—	<b>(4)</b>	(8)	—	<b>(8)</b>
Midstream revenue	9	—	<b>9</b>	—	—	<b>—</b>
<b>Oil and natural gas sales, net of blending<sup>(2)</sup></b>	<b>824</b>	<b>—</b>	<b>824</b>	<b>849</b>	<b>283</b>	<b>1,132</b>
<b>Expenses</b>						
Royalties	142	—	<b>142</b>	112	26	<b>138</b>
Production and operating	185	—	<b>185</b>	182	49	<b>231</b>
Transportation and processing	94	—	<b>94</b>	88	54	<b>142</b>
<b>Field operating income<sup>(2)</sup></b>	<b>403</b>	<b>—</b>	<b>403</b>	<b>467</b>	<b>154</b>	<b>621</b>
Depletion, depreciation and amortization	142	—	<b>142</b>	148	68	<b>216</b>
General and administrative	28	—	<b>28</b>	19	6	<b>25</b>
Finance costs	11	—	<b>11</b>	12	9	<b>21</b>
Other income	—	—	<b>—</b>	(1)	—	<b>(1)</b>
Interest	28	—	<b>28</b>	38	—	<b>38</b>
<b>Operating earnings</b>	<b>194</b>	<b>—</b>	<b>194</b>	<b>251</b>	<b>71</b>	<b>322</b>

(1) Comparative period has been revised to reflect current period presentation.

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

## PRODUCTION VOLUMES

	Three Months Ended		
	March 31, 2026	March 31, 2025 <sup>(1)</sup>	December 31, 2025
Bitumen (bbl/d)	61,375	65,016	62,538
Heavy oil (bbl/d)	54,695	50,488	54,660
Condensate and light oil (bbl/d)	78	19	57
Total oil production (bbl/d)	116,148	115,523	117,255
Other NGLs (bbl/d)	15	3	16
Natural gas (mcf/d)	2,268	2,000	2,444
Total (boe/d) - continuing operations	116,542	115,859	117,679
Total (boe/d) - discontinued operations	—	78,750	36
Total (boe/d)	116,542	194,609	117,715
% liquids - continuing operations	99.7 %	99.7 %	99.7 %

(1) Comparative period has been revised to reflect current period presentation.

Production volumes from continuing operations increased 1% (or 683 boe per day) for the three months ended March 31, 2026 to an average of 116,542 boe per day compared to 115,859 boe per day for the same period of 2025. The increase was driven by higher production at the Lloydminster Thermal segment, primarily attributable to the acquisition of the Vawn thermal heavy oil asset in the fourth quarter of 2025 (the "**Vawn Acquisition**"), which contributed average production of 6,152 boe per day during the first quarter of 2026. This increase was partially offset by lower production at the Cold Lake segment due to temporary gas supply issues from pipeline outages and at the Lloydminster Conventional segment as the result of reservoir conformance challenges in certain enhanced oil recovery projects and lower underlying base production.

Production volumes from continuing operations decreased 1% (or 1,137 boe per day) during the three months ended March 31, 2026 to an average of 116,542 boe per day compared to 117,679 boe per day for the three months ended December 31, 2025. The decrease was primarily due to downtime at the Cold Lake segment as the result of pipeline and plant issues and at the Lloydminster Thermal segment due to downhole maintenance. These decreases were partially offset by higher production at the Lloydminster Thermal segment due to the Vawn Acquisition, which increased production by 4,251 boe per day quarter over quarter.

## SALES VOLUMES

	Three Months Ended		
	March 31, 2026	March 31, 2025 <sup>(1)</sup>	December 31, 2025
Bitumen (bbl/d)	61,829	64,794	62,579
Heavy oil (bbl/d)	55,854	50,985	53,260
Condensate and light oil (bbl/d)	78	19	57
Total oil production (bbl/d)	117,761	115,798	115,896
Other NGLs (bbl/d)	15	3	16
Natural gas (mcf/d)	2,268	2,000	2,444
Total (boe/d) - continuing operations	118,155	116,134	116,319
Total (boe/d) - discontinued operations	—	78,750	36
Total (boe/d)	118,155	194,884	116,355

(1) Comparative period has been revised to reflect current period presentation.

Sales volumes typically trend with production volumes, except in cases of an inventory build or draw. Strathcona carries inventory on rail cars in transit to the U.S. Gulf Coast, on pipelines and in storage tanks.

For the three months ended March 31, 2026, pipeline inventory was sold to take advantage of higher market pricing, resulting in sales volumes exceeding production volumes.

## BUSINESS ENVIRONMENT

	Three Months Ended		
	March 31, 2026	March 31, 2025	December 31, 2025
<b>Benchmark Pricing</b>			
<i>US\$/bbl unless otherwise indicated</i>			
WTI <sup>(1)</sup>	<b>71.93</b>	71.42	59.14
WCS Hardisty <sup>(2)</sup>	<b>57.76</b>	58.75	47.94
WCS USGC <sup>(3)</sup>	<b>65.21</b>	67.74	55.63
WTI-WCS Hardisty differential	<b>(14.17)</b>	(12.67)	(11.20)
WTI-WCS USGC differential	<b>(6.72)</b>	(3.68)	(3.51)
NYMEX-AECO differential (US\$/MMbtu) <sup>(4)</sup>	<b>(3.41)</b>	(2.41)	(2.03)
Condensate differential <sup>(5)</sup>	<b>(0.53)</b>	(1.53)	(2.13)
Average Exchange rate (C\$/US\$)	<b>1.3716</b>	1.4348	1.3949
<i>CAD\$/bbl unless otherwise indicated</i>			
WTI <sup>(1)</sup>	<b>98.65</b>	102.47	82.50
WCS Hardisty <sup>(2)</sup>	<b>79.23</b>	84.30	66.89
WCS USGC <sup>(3)</sup>	<b>89.44</b>	97.19	77.61
AECO 5A (C\$/gj) <sup>(6)</sup>	<b>1.90</b>	2.05	2.11
Condensate par at Edmonton	<b>97.93</b>	100.28	79.54
AESO weighted average pool price (C\$/MWh) <sup>(7)</sup>	<b>32.51</b>	41.21	43.66
CORRA (%) <sup>(8)</sup>	<b>2.27</b>	3.05	2.34

(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").

During the first quarter of 2026, WTI pricing averaged US\$71.93 per bbl, a 22% increase from the fourth quarter of 2025. The primary driver of this increase was the initiation of military action in the Middle East, which ultimately led to the closure of the Strait of Hormuz, a critical energy transit choke point handling 20% of global oil supply. This supply gap led to a tightening of the global market, reversing the inventory builds observed at the end of 2025.

The WTI-WCS USGC differential widened by 91% and the WTI-WCS Hardisty differential widened by 27% in the first quarter of 2026, when compared to the fourth quarter of 2025. This was attributed to seasonal refinery maintenance and an increase in heavy supply sources for crude oil globally, primarily regarding Venezuela as U.S. policy evolved.

AECO 5A natural gas prices decreased in the first quarter of 2026 by 10%, when compared to the fourth quarter of 2025, primarily due to the seasonal decline in demand following heightened winter consumption.

## REVENUE AND REALIZED PRICES

### Oil and Natural Gas Sales – Net of Blending

(\$ millions, unless otherwise indicated)	Three Months Ended		
	March 31, 2026	March 31, 2025 <sup>(1)</sup>	December 31, 2025
Bitumen blend	647	722	549
Heavy oil, blended and raw	473	454	387
Natural gas	1	—	1
Oil and natural gas sales	1,121	1,176	937
Midstream revenue	9	—	8
Loss on purchased product	—	(1)	(1)
Bitumen – blending cost	(251)	(281)	(200)
Heavy oil – blending cost	(55)	(45)	(36)
Oil and natural gas sales, net of blending - continuing operations <sup>(2)</sup>	824	849	708
Oil and natural gas sales, net of blending - discontinued operations <sup>(2)</sup>	—	283	—
Oil and natural gas sales, net of blending <sup>(2)</sup>	824	1,132	708

(1) Comparative period has been revised to reflect current period presentation.

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

Oil and natural gas sales, net of blending from continuing operations decreased 3% (or \$25 million) for the three months ended March 31, 2026 to \$824 million compared to \$849 million in the same period of 2025. This decrease was related to lower oil benchmark pricing, partially offset by higher sales volumes, reduced blending costs due to lower condensate benchmark pricing and revenue from the Hardisty Rail Terminal that was acquired in April 2025 ("**HRT Acquisition**").

Oil and natural gas sales, net of blending from continuing operations increased 16% (or \$116 million) for the three months ended March 31, 2026 to \$824 million compared to \$708 million in the three months ended December 31, 2025. This increase was primarily due to stronger oil benchmark pricing and higher sales volumes, partially offset by an increase in blending costs as the result of increased blend ratios due to colder weather and an increase in condensate benchmark pricing.

## Average Realized Prices

(\$ millions, unless otherwise indicated)	Three Months Ended		
	March 31, 2026	March 31, 2025 <sup>(1)</sup>	December 31, 2025
Bitumen blend (\$/bbl) <sup>(2)</sup>	71.21	75.55	60.66
Heavy oil, blended and raw (\$/bbl) <sup>(2)</sup>	83.08	89.11	71.71
Condensate and light oil (\$/bbl)	—	117.99	—
Realized oil (\$/bbl)	76.84	83.80	65.74
Natural gas (\$/mcf)	2.23	1.67	1.52
Midstream revenue (\$/bbl)	0.84	—	0.75
Combined (\$/boe) - continuing operations	77.46	81.32	66.27
Combined (\$/boe) - discontinued operations	—	39.89	—
Combined (\$/boe)	77.46	64.58	66.27

(1) Comparative period has been revised to reflect current period presentation.

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

For the three months ended March 31, 2026, combined realized price from continuing operations decreased 5% (or \$3.86 per boe) compared to the same period of 2025. This decrease was primarily due to lower average WCS Hardisty and USGC benchmark pricing, partially offset by lower condensate pricing, which reduced per barrel blend costs.

Combined realized price from continuing operations increased 17% (or \$11.19 per boe) for the three months ended March 31, 2026 compared to the three months ended December 31, 2025. This increase was primarily due to higher average WTI benchmark pricing, partially offset by wider USGC and WCS Hardisty differentials and increased per barrel blend costs as the result of higher condensate benchmark pricing and higher blend ratios due to cold weather.

## ROYALTIES

(\$ millions, unless otherwise indicated)	Three Months Ended		
	March 31, 2026	March 31, 2025 <sup>(1)</sup>	December 31, 2025
Crown royalties	112	84	81
Freehold royalties	5	7	5
Gross overriding royalties	21	15	8
Other royalties	4	6	5
Royalties - continuing operations	142	112	99
Royalties - discontinued operations	—	26	—
Royalties	142	138	99
Effective royalty rate (%) - continuing operations <sup>(2)</sup>	17.2 %	13.2 %	14.0 %

(1) Comparative period has been revised to reflect current period presentation.

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

For the three months ended March 31, 2026, the effective royalty rate from continuing operations increased to 17.2%, from 13.2% in the comparable period in 2025. This increase was primarily attributable to higher eligible cost deductions at Cold Lake in 2025 and higher gross overriding royalty payments in the current year.

The effective royalty rate increased to 17.2%, from 14.0% for the three months ended December 31, 2025. These increases were primarily due to higher commodity prices and an increase in gross overriding royalties.

## PRODUCTION AND OPERATING EXPENSES

(\$ millions, unless otherwise indicated)	Three Months Ended		
	March 31, 2026	March 31, 2025 <sup>(1)</sup>	December 31, 2025
Production and operating – Energy	77	74	66
Production and operating – Non-energy	108	108	97
Production and operating expenses - continuing operations	185	182	163
Production and operating expenses - discontinued operations	—	49	(8)
Production and operating expenses	185	231	155
Production and operating – Energy - continuing operations (\$/boe)	7.19	7.08	6.26
Production and operating – Non-energy - continuing operations (\$/boe)	10.17	10.38	9.03
Production and operating expenses - continuing operations (\$/boe)	17.36	17.46	15.29

(1) Comparative period has been revised to reflect current period presentation.

Production and operating expenses from continuing operations increased 2% (or \$3 million) for the three months ended March 31, 2026 to \$185 million (\$17.36 per boe) from \$182 million (\$17.46 per boe) in the same period of 2025. Energy expenses increased by 4% (or \$3 million) primarily due to \$6 million of costs attributed to the Vawn Acquisition and higher fuel costs associated with the installation of new steam generation equipment at Lindbergh. These increases were partially offset by a decrease in carbon tax expense due to carbon credits applied in the first quarter of 2026, compared to the same period in 2025 which reflected full carbon tax with no credits, and a decrease in electricity and power costs as the result of lower benchmark prices. Non-energy expenses remained consistent at \$108 million for both the three months ended March 31, 2026 and 2025. There was, however, \$6 million of non-energy expenses attributed to the Vawn Acquisition, an increase in internal labor costs and costs related to the HRT Acquisition, offset by a decrease in chemical costs and lower surface maintenance costs.

Production and operating expenses from continuing operations increased 13% (or \$22 million) for the three months ended March 31, 2026 to \$185 million (\$17.36 per boe) from \$163 million (\$15.29 per boe) for the three months ended December 31, 2025. Energy expenses increased 17% (or \$11 million) primarily due to a \$4 million impact from the Vawn Acquisition and the installation of new steam generation equipment at Lindbergh, which increased fuel requirements. Non-energy expenses increased 11% (or \$11 million) primarily due to a \$5 million impact from the Vawn Acquisition, an increase in internal labor costs, higher property taxes and an increase in turnaround expenses.

## TRANSPORTATION EXPENSES

(\$ millions, unless otherwise indicated)	Three Months Ended		
	March 31, 2026	March 31, 2025 <sup>(1)</sup>	December 31, 2025
Transportation expenses - continuing operations	94	88	95
Transportation and processing expenses - discontinued operations	—	54	—
Transportation and processing expenses	94	142	95
\$ per boe - continuing operations	8.82	8.42	8.75

(1) Comparative period has been revised to reflect current period presentation.

Transportation expenses from continuing operations increased 7% (or \$6 million) for the three months ended March 31, 2026 to \$94 million (\$8.82 per boe) compared to \$88 million (\$8.42 per boe) in the same period of 2025. This increase was primarily

due to incremental pipeline costs of \$2 million associated with the Vawn Acquisition, an increase in bitumen transportation costs as the result of higher sales volumes at Orion and a thirteenth month adjustment recorded in the first quarter of 2026.

Transportation expenses from continuing operations decreased 1% (or \$1 million) for the three months ended March 31, 2026 to \$94 million (\$8.82 per boe) from \$95 million (\$8.75 per boe) in the three months ended December 31, 2025. This decrease was primarily due to lower volumes sold by rail, partially offset by incremental pipeline costs of \$1 million associated with the Vawn Acquisition, an increase in bitumen transportation costs related to Tucker and a thirteenth month adjustment recorded in the first quarter of 2026.

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

(\$ millions, unless otherwise indicated)	Three Months Ended		
	March 31, 2026	March 31, 2025 <sup>(1)</sup>	December 31, 2025
Depletion expense	134	138	142
Depreciation and amortization expense	8	10	10
DD&A - continuing operations	142	148	152
DD&A - discontinued operations	—	68	—
DD&A	142	216	152
\$ per boe - continuing operations	13.35	14.12	14.23

(1) Comparative period has been revised to reflect current period presentation.

DD&A expense from continuing operations decreased 4% (or \$6 million) for the three months ended March 31, 2026 to \$142 million (\$13.35 per boe) compared to \$148 million (\$14.12 per boe) for the same period of 2025. DD&A expense from continuing operations, for the three months ended March 31, 2026, decreased 7% (or \$10 million) to \$142 million (\$13.35 per boe) compared to \$152 million (\$14.23 per boe) for the three months ended December 31, 2025. These decreases were primarily due to an impairment loss of \$376 million recorded at year end 2025 at the Lloydminster Conventional segment, which lowered the depletable base for certain fields.

## GENERAL AND ADMINISTRATIVE EXPENSES ("G&A")

(\$ millions, unless otherwise indicated)	Three Months Ended		
	March 31, 2026	March 31, 2025 <sup>(1)</sup>	December 31, 2025
G&A expenses - continuing operations	28	19	24
G&A expenses - discontinued operations	—	6	—
G&A expenses	28	25	24
\$ per boe - continuing operations	2.65	1.83	2.23

(1) Comparative period has been revised to reflect current period presentation.

For the three months ended March 31, 2026, G&A expenses from continuing operations increased 47% (or \$9 million) compared to the same period of 2025. This increase was primarily due to a higher annual Company bonus payment and an increase in professional fees.

G&A expenses from continuing operations for the three months ended March 31, 2026 increased 17% (or \$4 million) compared to the three months ended December 31, 2025. This increase was primarily due to payment of the Company's annual bonus.

## INTEREST

(\$ millions, unless otherwise indicated)	Three Months Ended		
	March 31, 2026	March 31, 2025	December 31, 2025
Interest	28	38	24
Weighted average interest rate (%)	4.7 %	5.7 %	6.3 %

For the three months ended March 31, 2026, interest expense decreased 26% (or \$10 million) to \$28 million compared to \$38 million in the same period of 2025. This decrease was primarily due to lower debt balances, lower average interest rates and the repayment of the senior notes in December 2025.

Interest expense increased 17% (or \$4 million) to \$28 million for the three months ended March 31, 2026, compared to \$24 million for the three months ended December 31, 2025. This increase was primarily due to higher debt balances after the payment of the special distribution in December 2025, partially offset by lower average interest rates.

During the three months ended March 31, 2026, the Company recorded \$28 million in interest expense on the Credit Facilities (as defined in the "Capital Resources" section of this MD&A) (March 31, 2025 - \$27 million), a realized loss or gain of \$nil on interest rate swaps (March 31, 2025 - realized gain of \$1 million) and \$nil in interest expense on the senior notes (March 31, 2025 - \$12 million).

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

## TAX POOLS

As at March 31, 2026, the Company had approximately \$2,777 million (December 31, 2025 - \$2,790 million) of tax pools available for deduction in future periods as shown in the table below.

(\$ millions, unless otherwise indicated)	Annual Pool Deduction Rate	March 31, 2026		December 31, 2025
Canadian oil and gas property expenditures <sup>(1)</sup>	10%	271	254	
Canadian development expenditures <sup>(1)</sup>	30%	247	165	
Canadian exploration expenditures <sup>(1)</sup>	100%	12	3	
Undepreciated capital costs <sup>(2)</sup>	4% - 55%	1,286	1,232	
Non-capital losses	100%	727	897	
Other <sup>(3)</sup>		234	239	
<b>Total tax pools</b>		<b>2,777</b>	<b>2,790</b>	

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

(2) As at March 31, 2026, approximately 91% (December 31, 2025 - 91%) of costs in this pool have an annual deduction rate of 25% or higher.

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

## CAPITAL EXPENDITURES

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

(\$ millions, unless otherwise indicated)	Three Months Ended		
	March 31, 2026	March 31, 2025	December 31, 2025
Drilling, completion and equipping	132	199	44
Facilities and pipelines	128	120	94
Recompletion, workovers and polymer powder	16	19	15
Capitalized G&A and other expenditures	22	12	23
Capital expenditures <sup>(1)</sup>	298	350	176

(1) Capital expenditures includes continuing and discontinued operations.

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

(\$ millions, unless otherwise indicated)	Three Months Ended		
	March 31, 2026	March 31, 2025 <sup>(1)</sup>	December 31, 2025
Cold Lake	78	89	86
Lloydminster Thermal	160	91	61
Lloydminster Conventional	60	53	35
Corporate	—	—	6
Capital expenditures - continuing operations	298	233	188
Capital expenditures - discontinued operations	—	117	(12)
Capital expenditures	298	350	176

(1) Comparative period has been revised to reflect current period presentation.

For the three months ended March 31, 2026, drilling, completion and equipping activities accounted for 44% of capital expenditures as the Company drilled 85 new wells during the first quarter of 2026; 12 in Cold Lake, 27 in Lloydminster Thermal and 46 in Lloydminster Conventional. For the three months ended March 31, 2025, facilities and pipeline expenditures accounted for 43% of capital expenditures, and related primarily to the construction of the Meota Central processing facility, the equipping of pads at Meota East and Meota West 2, the Plover Lake Thermal Pilot central processing facility expansion and heat integration at Tucker.

## DECOMMISSIONING EXPENDITURES

The following table summarizes the Company's decommissioning expenditures by province.

(\$ millions, unless otherwise indicated)	Three Months Ended		
	March 31, 2026	March 31, 2025	December 31, 2025
Alberta	4	12	4
British Columbia	14	11	3
Saskatchewan	1	—	2
Total decommissioning expenditures <sup>(1)</sup>	19	23	9

(1) Decommissioning expenditures includes continuing and discontinued operations.

## ACQUISITIONS

### Selina Acquisition

On March 11, 2026, Strathcona acquired the remaining 50% working interest in the Selina property, located in the Cold Lake segment, along with additional surrounding lands, for total consideration of \$24 million, inclusive of closing adjustments. Following the acquisition, Strathcona holds a 100% operated working interest in Selina.

### Vawn Acquisition

In connection with the 2025 Vawn acquisition, contingent consideration of \$1 million is payable for each dollar per barrel that the Western Canadian Select ("**WCS**") benchmark crude oil price averages above C\$70.00 per barrel in a specified three-month period, payable quarterly over the 14-quarter period following the close of the transaction, up to a maximum of \$75 million. As at March 31, 2026, the fair value of the obligation was estimated at \$75 million (December 31, 2025 - \$33 million), based on the discounted present value of expected future payments using forecast WCS pricing and a 10% discount rate. The resulting \$42 million increase in fair value was recorded as an unrealized loss on the Condensed Consolidated Interim Statements of Income and Comprehensive Income.

## RISK MANAGEMENT

The Company's activities expose it to a variety of financial risks that arise from 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.

Upon 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 comprised 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 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 exposed to price fluctuations. 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 to sell oil as at the date of this MD&A.

Term	Contract	Index	Currency	Volume	Units	Price
Jan 1, 2026 - Dec 31, 2026	Swap	WCS	USD	50,000	bb/d	\$(12.00)

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

Term	Contract	Index	Currency	Volume	Units	Price
Jan 1, 2026 - Dec 31, 2026	Swap	AECO	CAD	100,000	GJ/d	\$2.00
Jan 1, 2027 - Dec 31, 2028	Swap	AECO	CAD	110,000	GJ/d	\$3.10

### Foreign Exchange Risk

The Company is exposed to fluctuations of the CAD to USD exchange rate given commodity pricing is directly influenced by U.S. dollar denominated benchmark pricing. In addition, the Company periodically borrows from its Credit Facilities in U.S. dollars (see the "Capital Resources" section of this MD&A). The Company actively manages foreign exchange risk using foreign exchange derivatives.

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

Term <sup>(1)</sup>	Contract	USD per Month	CAD/USD Floor	CAD/USD Ceiling
Mar 31, 2027 - Aug 31, 2028	Collar	100 million	1.3500	1.4500

(1) On the date that is three months prior to the start date for each month in the term, the Company is entered into the above collar if CAD/USD fixes at or above 1.3775. The collars have a European expiry date (i.e. exercise is based on CAD/USD on the last business day of the month).

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

### Interest Rate Risk

The Company is exposed to movements in floating interest rates on the Credit Facilities.

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

Notional (C\$)	Term	Contract	Index	Contract Price
1,500 million	Dec 1, 2025 - Dec 1, 2026	Floor	CORRA	2.25%
1,500 million	Dec 1, 2026 - May 1, 2028	Floor	CORRA	2.75%
1,500 million	May 1, 2028 - Dec 1, 2031	Swaption <sup>(1)</sup>	CORRA	3.09%

(1) The swap counterparties have the option to enter into a CORRA swap on April 28, 2028.

For a listing of the Company's commodity contracts, foreign exchange and interest rate contracts outstanding as at March 31, 2026, refer to Note 13 in the interim financial statements.

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

(\$ millions, unless otherwise indicated)	Three Months Ended		
	March 31, 2026	March 31, 2025	December 31, 2025
(Gain) loss on risk management contracts - realized	(16)	1	75
Loss (gain) loss on risk management contracts - unrealized	87	77	(74)
Total loss on risk management contracts	71	78	1
Realized (gain) loss on risk management contracts per boe <sup>(1)</sup>	(1.54)	0.05	7.01

(1) Calculated using sales volumes for both continuing and discontinued operations.

Strathcona realized a gain on risk management contracts of \$16 million for the three months ended March 31, 2026, compared to a loss of \$1 million for the same period in 2025 and a loss of \$75 million for the three months ended December 31, 2025. The realized gain was primarily due to higher contracted hedge pricing in comparison to realized commodity benchmark prices. The realized loss experienced in the three months ended December 31, 2025 was impacted by a cost of US\$43 million associated with the restructuring of WCS crude oil swaps.

As at March 31, 2026, the mark-to-market value of risk management contracts was a net liability of \$113 million (December 31, 2025 - net liability of \$26 million). Unrealized gains and losses represent the change in the mark-to-market values of these contracts due to the fluctuation of forward commodity prices, exchange rates and interest rates. The significant assumptions made in determining the fair value of financial instruments are disclosed in Note 13 of the interim financial statements.

## SEGMENT RESULTS

The Chief Operating Decision Makers ("**CODMs**") of the Company are comprised of the Chief Financial Officer, Chief Operating Officer and Chief Commercial Officer.

After divesting the Montney segment in 2025, the Company's CODMs disaggregated the Lloydminster segment into Lloydminster Thermal and Lloydminster Conventional to better reflect ongoing operations.

The CODMs assess performance based on the distinct attributes of its oil production operations. Each segment encompasses a group of assets with a unique combination of geographic focus, hydrocarbon resource type and extraction method, resulting in its own discrete economic profile. Segment profit is measured using Operating Earnings, which is the profit measure regularly reviewed by the CODMs for the purposes of performance assessment and resource allocation. The Company operates through three business segments:

- Cold Lake, which includes the development and production of bitumen in the Cold Lake region of Northern Alberta;
- Lloydminster Thermal, which includes the development and production of heavy oil through thermal steam-assisted gravity drainage methods in Southwest Saskatchewan; and
- Lloydminster Conventional, which includes the development and production of heavy oil through both conventional and enhanced oil recovery initiatives primarily in Southeast Alberta and Southwest Saskatchewan.

Activities not directly attributable to an operating segment are reported under Corporate and Midstream.

For the Three Months Ended (\$ millions, unless otherwise indicated)	Cold Lake Segment			Lloydminster Thermal Segment <sup>(1)</sup>			Lloydminster Conventional Segment <sup>(1)</sup>			Corporate and Midstream			Consolidated <sup>(1)</sup>		
	Mar 31, 2026	Mar 31, 2025	Dec 31, 2025	Mar 31, 2026	Mar 31, 2025	Dec 31, 2025	Mar 31, 2026	Mar 31, 2025	Dec 31, 2025	Mar 31, 2026	Mar 31, 2025	Dec 31, 2025	Mar 31, 2026	Mar 31, 2025	Dec 31, 2025
<b>Production volumes</b>															
Bitumen (bbl/d)	61,375	65,016	62,538	—	—	—	—	—	—	—	—	—	61,375	65,016	62,538
Heavy oil (bbl/d)	—	—	—	34,597	27,379	34,232	20,098	23,109	20,428	—	—	—	54,695	50,488	54,660
Condensate and light oil (bbl/d)	—	—	—	—	—	—	78	19	57	—	—	—	78	19	57
Other NGLs (bbl/d)	—	—	—	—	—	—	15	3	16	—	—	—	15	3	16
Natural gas (mcf/d)	—	—	—	—	—	—	2,268	2,000	2,444	—	—	—	2,268	2,000	2,444
Production volumes (boe/d)	61,375	65,016	62,538	34,597	27,379	34,232	20,570	23,464	20,908	—	—	—	116,542	115,859	117,679
<b>Sales volumes (boe/d)</b>	<b>61,829</b>	<b>64,794</b>	<b>62,579</b>	<b>35,649</b>	<b>27,996</b>	<b>33,052</b>	<b>20,677</b>	<b>23,344</b>	<b>20,688</b>	—	—	—	<b>118,155</b>	<b>116,134</b>	<b>116,319</b>
<b>Segment revenues</b>															
Oil and natural gas sales	647	721	549	304	251	243	170	204	144	—	—	1	1,121	1,176	937
Sale of purchased products	2	2	2	—	—	—	—	5	4	2	—	8	4	7	14
Blending costs	(251)	(281)	(200)	(32)	(8)	(10)	(23)	(37)	(26)	—	—	—	(306)	(326)	(236)
Purchased product	(2)	(3)	(2)	—	—	—	—	(5)	(4)	(2)	—	(9)	(4)	(8)	(15)
Midstream revenue	—	—	—	—	—	—	—	—	—	9	—	8	9	—	8
<b>Oil and natural gas sales, net of blending - continuing<sup>(2)</sup></b>	<b>396</b>	<b>439</b>	<b>349</b>	<b>272</b>	<b>243</b>	<b>233</b>	<b>147</b>	<b>167</b>	<b>118</b>	<b>9</b>	—	<b>8</b>	<b>824</b>	<b>849</b>	<b>708</b>
<b>Segment expenses</b>															
Royalties	101	69	69	21	18	14	20	25	16	—	—	—	142	112	99
Production and operating – Energy	35	40	34	33	24	24	9	10	8	—	—	—	77	74	66
Production and operating – Non-energy	44	53	43	30	25	24	29	30	25	5	—	5	108	108	97
Transportation	23	21	22	63	60	66	8	7	7	—	—	—	94	88	95
<b>Field Operating Income - Continuing<sup>(2)</sup></b>	<b>193</b>	<b>256</b>	<b>181</b>	<b>125</b>	<b>116</b>	<b>105</b>	<b>81</b>	<b>95</b>	<b>62</b>	<b>4</b>	—	<b>3</b>	<b>403</b>	<b>467</b>	<b>351</b>
Depletion, depreciation and amortization	44	43	44	62	58	63	34	43	42	2	4	3	142	148	152
General and administrative	10	7	9	10	6	8	8	6	7	—	—	—	28	19	24
Finance costs	1	1	1	—	1	1	—	—	—	10	10	13	11	12	15
Other income	—	—	—	—	—	—	—	—	—	—	(1)	(2)	—	(1)	(2)
Interest	—	—	—	—	—	—	—	—	—	28	38	24	28	38	24
<b>Operating Earnings - Continuing</b>	<b>138</b>	<b>205</b>	<b>127</b>	<b>53</b>	<b>51</b>	<b>33</b>	<b>39</b>	<b>46</b>	<b>13</b>	<b>(36)</b>	<b>(51)</b>	<b>(35)</b>	<b>194</b>	<b>251</b>	<b>138</b>
Impairment	—	—	—	—	—	—	—	—	376	—	—	—	—	—	376
(Gain) loss on risk management contracts - realized	—	—	—	—	—	—	—	—	—	(16)	1	75	(16)	1	75
Loss (gain) on risk management contracts - unrealized	—	—	—	—	—	—	—	—	—	87	77	(74)	87	77	(74)
Foreign exchange (gain) loss - realized	—	—	—	—	—	—	—	—	—	(1)	—	54	(1)	—	54
Foreign exchange loss (gain) - unrealized	—	—	—	—	—	—	—	—	—	5	(1)	(65)	5	(1)	(65)
Transaction related costs	—	—	—	—	—	—	—	—	—	—	1	25	—	1	25
Gain on marketable securities - realized	—	—	—	—	—	—	—	—	—	—	(23)	(171)	—	(23)	(171)
Loss on marketable securities - unrealized	—	—	—	—	—	—	—	—	—	—	—	69	—	—	69
Change in decommissioning liabilities	—	—	—	—	—	—	—	—	—	13	—	(13)	13	—	(13)
Loss on contingent consideration	—	—	—	—	—	—	—	—	—	42	—	—	42	—	—
Deferred tax expense (recovery)	—	—	—	—	—	—	—	—	—	—	—	—	25	43	(48)
<b>Income (loss) and comprehensive income (loss) from continuing operations</b>													<b>39</b>	<b>153</b>	<b>(90)</b>
Income (loss) and comprehensive income (loss) from discontinued operations, net of tax													—	<b>53</b>	<b>(9)</b>
<b>Income (loss) and comprehensive income (loss)</b>													<b>39</b>	<b>206</b>	<b>(99)</b>

(1) Comparative period has been revised to reflect current period presentation.

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

	Cold Lake Segment			Lloydminster Thermal Segment <sup>(1)</sup>			Lloydminster Conventional Segment <sup>(1)</sup>			Corporate and Midstream			Consolidated <sup>(1)</sup>		
	Mar 31, 2026	Mar 31, 2025	Dec 31, 2025	Mar 31, 2026	Mar 31, 2025	Dec 31, 2025	Mar 31, 2026	Mar 31, 2025	Dec 31, 2025	Mar 31, 2026	Mar 31, 2025	Dec 31, 2025	Mar 31, 2026	Mar 31, 2025	Dec 31, 2025
<b>For the Three Months Ended (\$/boe)</b>															
<b>Segment revenues</b>															
Oil and natural gas sales	79.56	84.17	66.93	85.89	96.45	76.70	79.76	84.68	66.88	—	—	—	81.21	86.61	69.22
Sale of purchased products	0.37	0.42	0.37	—	—	—	—	2.33	2.40	0.16	—	0.82	0.35	0.70	1.45
Blending costs	(8.34)	(8.58)	(6.28)	(1.03)	(0.10)	(0.22)	(1.16)	(5.37)	(4.28)	—	—	—	(4.58)	(5.27)	(3.69)
Purchased product	(0.38)	(0.46)	(0.36)	—	—	—	—	(2.33)	(2.39)	(0.16)	—	(0.84)	(0.36)	(0.72)	(1.46)
Midstream revenue	—	—	—	—	—	—	—	—	—	0.84	—	0.75	0.84	—	0.75
<b>Oil and natural gas sales, net of blending - continuing<sup>(2)</sup></b>	<b>71.21</b>	<b>75.55</b>	<b>60.66</b>	<b>84.86</b>	<b>96.35</b>	<b>76.48</b>	<b>78.60</b>	<b>79.31</b>	<b>62.61</b>	<b>0.84</b>	<b>—</b>	<b>0.73</b>	<b>77.46</b>	<b>81.32</b>	<b>66.27</b>
<b>Segment expenses</b>															
Royalties	18.24	11.90	12.10	6.44	7.28	4.67	10.69	11.77	7.87	—	—	—	13.36	10.76	9.23
Production and operating – Energy	6.23	6.94	6.05	10.17	9.59	8.06	4.79	4.43	4.03	0.02	—	—	7.19	7.08	6.26
Production and operating – Non-energy	7.82	9.18	7.51	9.44	9.86	7.83	15.78	14.36	12.86	0.47	—	0.48	10.17	10.38	9.03
Transportation	4.21	3.64	3.84	19.59	23.82	21.50	4.07	3.22	3.39	—	—	(0.02)	8.82	8.42	8.75
<b>Field Operating Netback - Continuing<sup>(2)</sup></b>	<b>34.71</b>	<b>43.89</b>	<b>31.16</b>	<b>39.22</b>	<b>45.80</b>	<b>34.42</b>	<b>43.27</b>	<b>45.53</b>	<b>34.46</b>	<b>0.35</b>	<b>—</b>	<b>0.27</b>	<b>37.92</b>	<b>44.68</b>	<b>33.00</b>
Depletion, depreciation and amortization	7.83	7.41	7.73	19.35	23.12	20.87	18.33	20.15	21.76	0.21	0.37	0.26	13.35	14.12	14.23
General and administrative	1.83	1.23	1.49	3.11	2.52	2.64	4.23	2.70	3.79	0.01	—	—	2.65	1.83	2.23
Finance costs	0.13	0.13	0.13	0.14	0.35	0.19	0.01	0.02	0.02	0.97	1.02	1.29	1.08	1.18	1.42
Other income	—	—	—	—	—	—	—	—	—	(0.02)	(0.12)	(0.13)	(0.02)	(0.12)	(0.13)
Interest	—	—	—	—	—	—	—	—	—	2.62	3.68	2.16	2.62	3.68	2.16
<b>Operating Earnings - Continuing</b>	<b>24.92</b>	<b>35.12</b>	<b>21.81</b>	<b>16.62</b>	<b>19.81</b>	<b>10.72</b>	<b>20.70</b>	<b>22.66</b>	<b>8.89</b>	<b>(3.44)</b>	<b>(4.95)</b>	<b>(3.31)</b>	<b>18.24</b>	<b>23.99</b>	<b>13.09</b>
Effective royalty rate (%) <sup>(2)</sup>	25.5	15.8	19.8	7.7	7.5	6.0	13.6	14.8	13.6	—	—	—	17.2	13.2	14.0

(1) Comparative period has been revised to reflect current period presentation.

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

## Cold Lake Segment

Production at the Cold Lake segment for the three months ended March 31, 2026 decreased to 61,375 boe per day compared to 65,016 boe per day in the same period of 2025. This decrease was primarily due to temporary gas supply issues from pipeline outages at Lindbergh and a decrease in production at Tucker, partially offset by an increase in production at Orion.

Oil and natural gas sales, net of blending, decreased to \$396 million (\$71.21 per boe) during the three months ended March 31, 2026 compared to \$439 million (\$75.55 per boe) for the same period of 2025. This decrease was primarily due to lower WCS Hardisty benchmark pricing and a decrease in sales volumes, partially offset by reduced blending costs due to lower condensate benchmark pricing.

The effective royalty rate for the three months ended March 31, 2026 increased to 25.5% from 15.8% in the same period of 2025. This increase was primarily attributable to higher eligible cost deductions in 2025 and higher gross overriding royalty payments in the current year.

Energy related production and operating expenses for the three months ended March 31, 2026 decreased to \$35 million (\$6.23 per boe) from \$40 million (\$6.94 per boe) in the same period in 2025. This decrease was primarily due to lower carbon tax expense due to carbon credits applied in the current quarter and a decrease in electricity and power costs due to lower benchmark prices.

Non-energy related production and operating expenses for the three months ended March 31, 2026 decreased to \$44 million (\$7.82 per boe) from \$53 million (\$9.18 per boe) in the same period in 2025. This decrease was primarily due to lower chemical and surface maintenance costs, partially offset by increased internal labor expense in the current quarter.

For the three months ended March 31, 2026, transportation expenses increased to \$23 million (\$4.21 per boe) compared to \$21 million (\$3.64 per boe) in the same period of 2025. This increase was primarily due to the application of make-up right credits in the comparable period in 2025.

Depletion, depreciation and amortization remained consistent for the three months ended March 31, 2026 at \$44 million (\$7.83 per boe), compared to \$43 million (\$7.41 per boe) in the same period of 2025. The slight increase reflects a higher proportion of sales volumes from areas with a higher per barrel rate of depletion.

General and administrative for the three months ended March 31, 2026 increased to \$10 million (\$1.83 per boe) compared to \$7 million (\$1.23 per boe) in the same period of 2025. This increase was primarily due to a higher annual Company bonus payment and professional fees as well as the reallocation of corporate costs across the business following the sale of the Montney segment.

## Lloydminster Thermal Segment

Production at the Lloydminster Thermal segment for the three months ended March 31, 2026, increased to 34,597 boe per day compared to 27,379 boe per day in the same period of 2025. This increase was due to approximately 6,000 boe per day associated with the Vawn Acquisition and production increases at Meota West 2 from wells brought on stream as part of the Company's capital program, partially offset by elevated water cuts and acid stimulation work at Edam.

Oil and natural gas sales, net of blending, increased to \$272 million (\$84.86 per boe) during the three months ended March 31, 2026 compared to \$243 million (\$96.35 per boe) for the same period of 2025. This increase was primarily attributable to higher sales volumes, partially offset by lower WCS USGC and Hardisty benchmark prices.

The effective royalty rate for the three months ended March 31, 2026 remained consistent at 7.7%, compared to 7.5% in the same period of 2025.

Energy related production and operating expenses for the three months ended March 31, 2026 increased to \$33 million (\$10.17 per boe) compared to \$24 million (\$9.59 per boe) for the same period in 2025. This increase was primarily due to \$6 million in costs associated with the Vawn Acquisition.

Non-energy related production and operating expenses for the three months ended March 31, 2026 increased to \$30 million (\$9.44 per boe) compared to \$25 million (\$9.86 per boe) in the same period of 2025. This increase was primarily due to \$6 million in costs associated with the Vawn Acquisition.

For the three months ended March 31, 2026, transportation expenses increased to \$63 million (\$19.59 per boe) compared to \$60 million (\$23.82 per boe) in the same period of 2025. This increase was primarily due to \$2 million in costs associated with the Vawn Acquisition and higher overall sales volumes. Despite the increase in absolute costs, the decrease on a per boe

basis reflects that the majority of the incremental costs relate to Vawn volumes, which are transported by pipeline and therefore incur lower per barrel transportation costs.

Depletion, depreciation and amortization for the three months ended March 31, 2026 increased to \$62 million (\$19.35 per boe) compared to \$58 million (\$23.12 per boe) in the same period of 2025. This increase was due to higher sales volumes, primarily at Vawn and Meota West 2.

General and administrative for the three months ended March 31, 2026 increased to \$10 million (\$3.11 per boe) compared to \$6 million (\$2.52 per boe) in the same period of 2025. This increase was primarily due to a higher annual Company bonus payment and the reallocation of corporate costs across the business following the sale of the Montney segment.

### **Lloydminster Conventional Segment**

Production at the Lloydminster Conventional segment for the three months ended March 31, 2026, decreased to 20,570 boe per day compared to 23,464 boe per day in the same period of 2025. This decrease was primarily due to reservoir conformance challenges in certain enhanced oil recovery projects and lower underlying base production in maturing fields.

Oil and natural gas sales, net of blending, decreased to \$147 million (\$78.60 per boe) during the three months ended March 31, 2026 compared to \$167 million (\$79.31 per boe) for the same period of 2025. This decrease was primarily attributable to lower WCS Hardisty benchmark pricing and decreased sales volumes.

The effective royalty rate for the three months ended March 31, 2026 decreased to 13.6%, compared to 14.8% in the same period of 2025. This decrease was primarily due to lower average benchmark commodity prices.

Energy related production and operating expenses for the three months ended March 31, 2026 decreased to \$9 million (\$4.79 per boe) compared to \$10 million (\$4.43 per boe) for the same period in 2025. This decrease was primarily due to lower electricity and power costs due to a reduction in benchmark pricing.

Non-energy related production and operating expenses for the three months ended March 31, 2026 decreased to \$29 million (\$15.78 per boe) compared to \$30 million (\$14.36 per boe) in the same period of 2025. This decrease was primarily due to lower surface maintenance costs.

For the three months ended March 31, 2026, transportation expenses increased to \$8 million (\$4.07 per boe) compared to \$7 million (\$3.22 per boe) in the same period of 2025. This slight increase was primarily due to a thirteenth month adjustment recorded in the first quarter of 2026.

Depletion, depreciation and amortization for the three months ended March 31, 2026 decreased to \$34 million (\$18.33 per boe) compared to \$43 million (\$20.15 per boe) in the same period of 2025. This decrease was primarily due to the impairment loss of \$376 million recorded at year end 2025, which lowered the depletable base for Lloydminster Conventional fields.

General and administrative for the three months ended March 31, 2026 increased to \$8 million (\$4.23 per boe) compared to \$6 million (\$2.70 per boe) in the same period of 2025. This increase was primarily due to a higher annual Company bonus payment and the reallocation of corporate costs across the business following the sale of the Montney segment.

### **Midstream**

Strathcona's midstream operations are comprised of the wholly-owned Hardisty Rail Terminal, acquired in April 2025, which has throughput of approximately 40,000 barrels per day, the majority of which is committed under take-or-pay arrangements with an investment-grade third-party shipper.

Midstream revenue for the three months ended March 31, 2026 was \$9 million (\$0.84 per boe), compared to \$nil for the same period in 2025. Non-energy related production and operating expenses associated with midstream operations, for the three months ended March 31, 2026, was \$5 million (\$0.47 per boe), compared to \$nil for the same period in 2025.

## CAPITAL RESOURCES

### Bank Credit Facilities

#### *Covenant-Based Revolving Credit Facility and Term Credit Facility*

At March 31, 2026, the Company had a covenant-based revolving credit facility of \$3.24 billion (December 31, 2025 - \$3.24 billion) with a syndicate of Canadian, U.S. and international financial institutions (the "**Revolving Credit Facility**") and a US\$175 million covenant-based term facility (December 31, 2025 - US\$175 million) (the "**Term Credit Facility**" and together with the Revolving Credit Facility, the "**Credit Facilities**"). The agreement governing the Credit Facilities (the "**Credit Agreement**") includes an accordion feature which permits the Company to increase the available Credit Facilities by up to an additional \$265 million, subject to the satisfaction of certain conditions.

The Credit Facilities have a maturity date of March 28, 2030. There are no mandatory payments on either the Revolving Credit Facility or the Term Credit Facility. Borrowings under the Revolving Credit Facility may be drawn and repaid from time to time by the Company in Canadian or U.S. dollars. Borrowings under the Term Credit Facility were made in a single upfront draw in U.S. dollars and amounts repaid by the Company may not be re-borrowed. The Credit Facilities are not subject to annual or semi-annual reviews.

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

At March 31, 2026, the Company had letters of credit outstanding under the Revolving Credit Facility of \$2 million (December 31, 2025 - \$2 million).

#### *Foreign Exchange Risk Management on U.S. Denominated Bank Debt*

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

Foreign currency risk associated with these borrowings is offset at the time of borrowing as cross-currency interest rate swap contracts fix the principal and interest payments due at maturity. Debt on the balance sheet includes the Canadian dollar equivalent of U.S. borrowings translated at the period end exchange rate, which does not include the offsetting impact of cross-currency interest rate swaps. As at March 31, 2026 the cross-currency swap asset was \$26 million (December 31, 2025 – a liability of \$5 million) and total debt includes an unrealized loss of \$26 million (December 31, 2025 – unrealized gain of \$5 million) related to U.S. borrowings on the Credit Facilities. Unrealized gains or losses on U.S. borrowings and offsetting unrealized gains or losses on cross-currency interest swap contracts are included in foreign exchange gains or losses in the interim financial statements.

As at March 31, 2026, the Company had the following cross-currency interest rate swap contracts outstanding:

Notional (US\$)	Maturity Date	Contract Price
1,344 million	April 24, 2026	CAD/USD 1.3743
175 million	April 27, 2026	CAD/USD 1.3749

#### *Financial Covenants*

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

- (i) Total Debt to Adjusted EBITDA Ratio – All debt, excluding 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.

- (ii) Senior Debt to Adjusted EBITDA Ratio – Total Debt excluding permitted junior debt, as defined in the Credit Agreement, shall not exceed 3.5 times trailing 12-month Adjusted EBITDA.
- (iii) Interest Coverage Ratio – Trailing 12-month Adjusted EBITDA, shall not be less than 3.5 times cash interest expense, as defined in the Credit Agreement.

As at March 31, 2026, the Company was in compliance with such financial covenants.

### **Demand Letter of Credit Facility**

As at March 31, 2026, the Company had a \$200 million (December 31, 2025 - \$200 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 ("**EDC**") in favor of the financial institution. The Company and its subsidiaries have indemnified EDC for the amount of any payment made by EDC to the financial institution pursuant to such account performance security guarantee; however, the obligations under such indemnity are unsecured. The letters of credit outstanding under the LC Facility do not impact the Company's borrowing capacity under the Revolving Credit Facility. As at March 31, 2026, the Company had letters of credit in the amount of \$57 million (December 31, 2025 - \$57 million) outstanding under the LC Facility.

## CAPITAL MANAGEMENT AND LIQUIDITY

The Company's policy is to maintain a strong capital base with the objectives of preserving financial flexibility, upholding creditor and market confidence, and sustaining the business's future development. 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, debt and working capital.

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

The availability under the Credit Facilities are summarized in the following table.

As at	March 31, 2026	December 31, 2025
Revolving Credit Facility capacity	3,240	3,240
Term Credit Facility capacity <sup>(1)</sup>	244	240
Credit Facilities capacity	3,484	3,480
Credit Facilities debt <sup>(1)</sup>	(2,125)	(2,116)
Unrealized loss (gain) on U.S. borrowings	26	(5)
Letters of credit outstanding	(2)	(2)
Availability	1,383	1,357

(1) CAD equivalent converted at the period end exchange rate.

The Company has a working capital deficiency as part of its current capital structure. As at March 31, 2026, the working capital deficiency was \$475 million (December 31, 2025 - deficiency of \$396 million). Management believes that 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, make scheduled interest payments, fund planned capital expenditures and fund the other needs of the business for at least the next 12 months. However, no assurance can be given that this will be the case or that future or additional sources of capital will not be necessary. The Company's cash flow and the development of projects are subject to certain risk factors discussed in the "Risk Factors" section of the Company's annual information form for the year ended December 31, 2025.

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The oil and natural gas industry is cyclical and commodity prices can be volatile, both of which are expected to impact the Company's future revenue and profitability. A sustained decline in commodity prices and increased inflation and interest rates could adversely affect our business, financial condition and results of operations, liquidity and ability to meet financial commitments when due or delay planned capital expenditures. The imposition of tariffs or other tariff barriers may negatively impact the Company's realized prices, the timing of cash flows where production is directly exported by the Company and may increase certain of the Company's input costs.

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

## CONTRACTUAL OBLIGATIONS AND OFF-BALANCE SHEET ARRANGEMENTS

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

The following tables detail the undiscounted cash flows and contractual maturities of the Company's financial liabilities as at March 31, 2026.

	Total	< 1 year	1-3 years	4-5 years	> 5 years
Credit Facilities <sup>(1)</sup>	2,099	—	—	2,099	—
Accounts payable and accrued liabilities	817	817	—	—	—
Risk management contract liability	113	17	96	—	—
Lease obligations <sup>(2)</sup>	87	29	22	10	26
Contingent consideration	75	75	—	—	—
<b>Total</b>	<b>3,191</b>	938	118	2,109	26

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

(2) Amounts relate to undiscounted payments for lease obligations.

As at March 31, 2026, the Company was committed to the following non-cancellable payments.

	Total	< 1 year	1-3 years	4-5 years	> 5 years
Transportation and processing	2,616	166	305	376	1,769
Capital	142	129	13	—	—
Other	66	21	44	1	—
<b>Total</b>	<b>2,824</b>	316	362	377	1,769

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

## SHARE CAPITAL

The authorized capital of the Company consists of an unlimited number of common shares and an unlimited number of preferred shares. No preferred shares have been issued by the Company as at March 31, 2026 (December 31, 2025 – \$nil).

The following table summarizes the number of shares outstanding as at May 6, 2026:

Share Class	Shares Outstanding at May 6, 2026
Common shares	214,235,608

### Share Pass-through Transactions

On March 5, 2026, one WEF limited partnership completed a share pass-through transaction that resulted in the disposition of 7,102,958 Strathcona common shares (the "**March Pass-through Transaction**"). Following the March Pass-through Transaction, WEF's ownership of Strathcona's outstanding common shares decreased from approximately 69.9% to approximately 66.6%.

The March Pass-through Transaction was comprised of a series of reorganizational steps, which included the issuance by Strathcona of 7,102,958 common shares to partners of the WEF limited partnership upon the dissolution of such limited partnership. Notwithstanding such issuance, the number of issued and outstanding common shares remained the same following completion of the March Pass-through Transaction.

### Dividends

During the three months ended March 31, 2026, Strathcona declared and paid total dividends of \$64 million (\$0.30 per common share) (March 31, 2025 - \$56 million (\$0.26 per common share)).

On May 6, 2026, the Strathcona Board of Directors declared a quarterly dividend of \$0.30 per common share to be paid on June 17, 2026 to all shareholders of record on June 8, 2026.

### Normal Course Issuer Bid

On March 12, 2026, the Toronto Stock Exchange approved Strathcona's normal course issuer bid ("**NCIB**") to acquire up to 5% of its issued and outstanding shares (up to a maximum of approximately 10.7 million common shares of the Company). The NCIB commenced on March 17, 2026 and will terminate on March 16, 2027 or such earlier time as the maximum number of common shares has been purchased or Strathcona decides not to make any further purchases. For the three months ended March 31, 2026, no common shares were repurchased under the NCIB.

## SUMMARY OF QUARTERLY RESULTS

(\$ millions, unless otherwise indicated)	2026	2025				2024 <sup>(1)</sup>		
	Q1	Q4	Q3	Q2	Q1 <sup>(1)</sup>	Q4	Q3	Q2
<b>Operating results (boe/d)</b>								
Average production volumes	<b>116,542</b>	117,715	116,201	181,368	194,609	187,203	178,235	181,766
Continuing operations	<b>116,542</b>	117,679	115,584	108,926	115,859	111,013	109,328	110,925
Discontinued operations	—	36	617	72,442	78,750	76,190	68,907	70,841
<b>Financial Results</b>								
Oil and natural gas sales	<b>1,121</b>	937	1,012	1,209	1,459	1,293	1,272	1,472
Continuing operations	<b>1,121</b>	937	1,009	974	1,176	1,043	1,059	1,231
Discontinued operations	—	—	3	235	283	250	213	241
Net income (loss)	<b>39</b>	(99)	573	231	206	88	188	227
Continuing operations	<b>39</b>	(90)	144	158	153	50	184	203
Discontinued operations	—	(9)	429	73	53	38	4	24
Net income (loss) per share	<b>0.18</b>	(0.47)	2.68	1.08	0.96	0.41	0.88	1.06
Continuing operations	<b>0.18</b>	(0.42)	0.68	0.74	0.71	0.23	0.86	0.95
Discontinued operations	—	(0.05)	2.00	0.34	0.25	0.18	0.02	0.11
Operating Earnings	<b>194</b>	146	236	226	322	190	265	306
Continuing operations	<b>194</b>	138	227	128	251	137	253	272
Discontinued operations <sup>(2)</sup>	—	8	9	98	71	53	12	34
Free Cash Flow <sup>(2)</sup>	<b>47</b>	53	94	32	185	(1)	201	247
Continuing operations <sup>(2)</sup>	<b>47</b>	33	85	44	169	1	105	247
Discontinued operations <sup>(2)</sup>	—	20	9	(12)	16	(2)	96	—
Capital expenditures <sup>(3)</sup>	<b>298</b>	176	281	379	350	393	320	298
Decommissioning expenditures <sup>(3)</sup>	<b>19</b>	9	8	3	23	13	9	3

(1) Comparative periods have been revised to reflect current period presentation.

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

(3) Includes continuing and discontinued operations.

Over the past eight quarters, the Company's oil and natural gas sales have fluctuated due to the volatility in the crude oil, condensate and natural gas benchmark prices, oil price differentials, changes in production, the Groundbirch Asset Sale, the Kakwa and Grande Prairie Asset Sales and the Vawn Acquisition. The Company's production has fluctuated due to asset acquisitions and dispositions, changes in its development capital spending levels and natural declines.

Net income (loss) has fluctuated over the past eight quarters primarily due to the changes in Funds from Operations, the Groundbirch Asset Sale, the Kakwa and Grande Prairie Asset Sales, the Vawn Acquisition, unrealized gains and losses from risk management contracts, which fluctuate with changes in forward market prices and foreign exchange rates, unrealized gain on marketable securities, which fluctuate with changes in listed share prices, 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 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.

## SPECIFIED FINANCIAL MEASURES

### Non-GAAP and Other 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, sale of purchased product and midstream revenue. Management uses this metric to isolate the revenue associated with the Company's operations 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 sale 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 "**Effective royalty rate**" is calculated by dividing royalties by oil and natural gas sales, sale of purchased product and midstream revenue, 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.

"**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. Quantitative reconciliations of Field Operating Income and Field Operating Netback to the most directly comparable GAAP financial measure, oil and natural gas sales, are contained under the headings "*Presentation of Continuing and Discontinued Operations*" and "*Segment Results*", respectively, of this MD&A.

"**Operating Earnings - Discontinued**" is considered a key financial metric for evaluating the profitability of Strathcona's discontinued business. "**Operating Earnings - Continuing**" is a GAAP financial measure as it is used by the Company's CODMs to evaluate profit or loss and is presented in the interim financial statements. A quantitative reconciliation of Operating Earnings - Discontinued to the most directly comparable GAAP financial measure, Oil and natural gas sales, is contained under the heading "*Presentation of Continuing and Discontinued Operations*" of this MD&A.

"**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 Operating Earnings and adjusted for DD&A, finance costs, gains and losses on risk management contracts – realized and gains and losses on foreign exchange - realized, operating.

"**Free Cash Flow**" indicates funds available for deleveraging, funding future growth, or shareholder returns. Free Cash Flow is derived from Operating Earnings and adjusted for DD&A, finance costs, gains and losses on risk management contracts – realized and gains and losses on foreign exchange - realized, operating, capital expenditures and decommissioning costs.

Quantitative reconciliations of Funds from Operations and Free Cash Flow for both continuing and discontinued operations to the most directly comparable GAAP financial measure, Operating Earnings, are set forth below.

(\$ millions, unless otherwise indicated)	Three Months Ended		
	March 31, 2026	March 31, 2025 <sup>(1)</sup>	December 31, 2025
<b>Operating Earnings - Continuing</b>	<b>194</b>	251	138
Depletion, depreciation and amortization	142	148	152
Finance costs	11	12	15
Gain (loss) on risk management contracts - realized	16	(1)	(75)
Foreign exchange gain - realized, operating	1	—	—
<b>Funds from Operations - Continuing</b>	<b>364</b>	410	230
Capital expenditures	(298)	(233)	(188)
Decommissioning costs	(19)	(8)	(9)
<b>Free Cash Flow - Continuing</b>	<b>47</b>	169	33

(1) Comparative period has been revised to reflect current period presentation.

(\$ millions, unless otherwise indicated)	Three Months Ended		
	March 31, 2026	March 31, 2025 <sup>(1)</sup>	December 31, 2025
<b>Operating Earnings - Discontinued</b>	<b>—</b>	71	8
Depletion, depreciation and amortization	—	68	—
Finance costs	—	9	—
<b>Funds from Operations - Discontinued</b>	<b>—</b>	148	8
Capital expenditures	—	(117)	12
Decommissioning costs	—	(15)	—
<b>Free Cash Flow - Discontinued</b>	<b>—</b>	16	20

(1) Comparative period has been revised to reflect current period presentation.

The following table reconciles Operating Earnings, Funds from Operations and Free Cash Flow from continuing and discontinued operations:

(\$ millions, unless otherwise indicated)	Three Months Ended		
	March 31, 2026	March 31, 2025 <sup>(1)</sup>	December 31, 2025
<b>Operating Earnings</b>	<b>194</b>	322	146
Depletion, depreciation and amortization	142	216	152
Finance costs	11	21	15
Gain (loss) on risk management contracts - realized	16	(1)	(75)
Foreign exchange gain - realized, operating	1	—	—
Funds from Operations	<b>364</b>	558	238
Capital expenditures	(298)	(350)	(176)
Decommissioning costs	(19)	(23)	(9)
<b>Free Cash Flow</b>	<b>47</b>	185	53

(1) Comparative period has been revised to reflect current period presentation.

## 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 judgments in preparing interim financial statements are discussed in Note 2 of the annual financial statements.

On January 1, 2026, Strathcona adopted Amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures, relating to settling financial liabilities using an electronic payment system and the assessment of contractual cash flow characteristics of financial assets. There was not a material impact to the Company's financial statements.

## 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*. The certification of interim filings for the interim period ended March 31, 2026 requires that Strathcona disclose in the MD&A any changes in Strathcona's internal controls over financial reporting ("**ICFR**") that occurred during the period that have materially affected, or are reasonably likely to materially affect, Strathcona's ICFR. Strathcona confirms that no such changes were made to its ICFR during the three months ended March 31, 2026.

## ADVISORIES REGARDING OIL & GAS INFORMATION

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

National Instrument 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.

The Company's three months ended average daily production volumes for 2026 and 2025, and the references to "natural gas", "crude oil" and "total liquids", 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:

	<b>Three Months Ended</b>		
	<b>March 31, 2026</b>	March 31, 2025 <sup>(1)</sup>	December 31, 2025
<b>Cold Lake segment</b>			
Heavy crude oil (bbl/d)	—	—	—
Light and medium crude oil (bbl/d)	—	—	—
Total crude oil (bbl/d)	—	—	—
Bitumen (bbl/d)	61,375	65,016	62,538
NGLs (bbl/d)	—	—	—
Total liquids (bbl/d)	61,375	65,016	62,538
Conventional natural gas (mcf/d)	—	—	—
Total (boe/d)	61,375	65,016	62,538
<b>Lloydminster Thermal segment<sup>(1)</sup></b>			
Heavy crude oil (bbl/d)	34,597	27,379	34,232
Light and medium crude oil (bbl/d)	—	—	—
Total crude oil (bbl/d)	34,597	27,379	34,232
Bitumen (bbl/d)	—	—	—
NGLs (bbl/d)	—	—	—
Total liquids (bbl/d)	34,597	27,379	34,232
Conventional natural gas (mcf/d)	—	—	—
Total (boe/d)	34,597	27,379	34,232
<b>Lloydminster Conventional segment<sup>(1)</sup></b>			
Heavy crude oil (bbl/d)	20,098	23,109	20,428
Light and medium crude oil (bbl/d)	69	17	61
Total crude oil (bbl/d)	20,167	23,126	20,489
Bitumen (bbl/d)	—	—	—
NGLs (bbl/d)	24	5	12
Total liquids (bbl/d)	20,191	23,131	20,501
Conventional natural gas (mcf/d)	2,268	2,000	2,444
Total (boe/d)	20,570	23,464	20,908
<b>Discontinued operations</b>			
Heavy crude oil (bbl/d)	—	—	—
Light and medium crude oil (bbl/d)	—	487	—
Total crude oil (bbl/d)	—	487	—
Bitumen (bbl/d)	—	—	—
NGLs (bbl/d)	—	32,010	18
Total liquids (bbl/d)	—	32,497	18
Conventional natural gas (mcf/d)	—	277,517	114
Total (boe/d)	—	78,750	36

(1) Comparative period has been revised to reflect current period presentation.

	Three Months Ended		
	March 31, 2026	March 31, 2025 <sup>(1)</sup>	December 31, 2025
<b>Consolidated</b>			
Heavy crude oil (bbl/d)	54,695	50,488	54,660
Light and medium crude oil (bbl/d)	69	504	61
Total crude oil (bbl/d)	54,764	50,992	54,721
Bitumen (bbl/d)	61,375	65,016	62,538
NGLs (bbl/d)	24	32,015	30
Total liquids (bbl/d)	116,163	148,023	117,289
Conventional natural gas (mcf/d)	2,268	279,517	2,558
Total (boe/d)	116,542	194,609	117,715

(1) Comparative period has been revised to reflect current period presentation.

## 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", "should", "project", "believe", "depends", "could", "guidance", "plan", "manages" 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 normal course issuer bid; the declaration and payment of dividends, including the amount and timing thereof; the Company's use of hedging arrangements; the Company's ability to meet current and future obligations, including making scheduled principal and interest payments, to fund planned capital expenditures and to fund the other needs of the business; future liquidity and financial capacity; anticipated proceeds from financial instruments, including commodity contracts; and sources of funding for the Company's capital program, the terms of Strathcona's future contractual obligations, including its obligations under the Credit Agreement and oil and natural gas prices and differentials.

All forward-looking information reflects Strathcona's beliefs and assumptions based on information available at the time the applicable forward-looking information is disclosed and in light of the Company's current expectations with respect to such things as: the success of Strathcona's operations and growth and expansion projects; expectations regarding production growth, future well production rates and reserve volumes; expectations regarding Strathcona's capital program; Strathcona's ability to declare and pay dividends; expectations regarding the impact of tariffs on Strathcona's operations and its ability to effectively mitigate the impact thereof; the outlook for general economic trends, industry trends, prevailing and future commodity prices, foreign exchange rates and interest rates; prevailing and future royalty regimes and tax laws; future well production rates and reserve volumes; fluctuations in energy prices based on worldwide demand and geopolitical events; the impact of inflation; the integrity and reliability of Strathcona's assets; decommissioning obligations; Strathcona's ability to comply with its financial covenants; and the governmental, regulatory and legal environment, including expectations regarding the current and future carbon tax regime and regulations.

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 conflict in the Middle East, including the closure of the Strait of Hormuz, ongoing Russia/Ukraine conflict, and other heightened geopolitical risks, including the imposition of tariffs or other trade barriers, and the ability of the Company to carry on operations as contemplated in light of the foregoing; determinations by the Organization of the Petroleum Exporting Countries and other countries as to production levels; unanticipated operating results or production declines; changes in tax or environmental laws, climate change, royalty rates or other regulatory matters; changes in Strathcona's development plans or by third party operators of Strathcona's properties; failure to achieve anticipated results of its operations; competition from other producers; inability to retain drilling rigs and other services; failure to realize the anticipated benefits of the Company's acquisitions, dispositions or corporate reorganizations; failure to execute the Company's growth strategy and objectives; 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, unfavorable or a lack of access to capital markets or other sources of capital; increased costs; a lack of adequate insurance coverage; the impact of competitors; and the other factors discussed under the "Risk Factors" section in the Company's management's discussion and analysis and annual information form for the year ended December 31, 2025, a copy of each of which is available on the internet under the Company's SEDAR+ profile at [www.sedarplus.ca](http://www.sedarplus.ca).

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, 2025 and the interim financial statements, can be found on the internet under the Company's SEDAR+ profile at [www.sedarplus.ca](http://www.sedarplus.ca) and on the Company's website at [www.strathconaresources.com](http://www.strathconaresources.com).