2025
Annual Report

About Strathcona

Strathcona Resources Ltd. stands out as one of North America's fastest growing pure play heavy oil producers. Headquartered in Calgary, Alberta, Strathcona operates primarily in the Cold Lake and Lloydminster regions of Alberta and Saskatchewan, focusing on thermal oil and enhanced oil recovery.

Strathcona's strategy centers on acquiring established, long-life assets within its core areas and developing them organically to optimize reserve life, a proven approach that has set the company apart from its peers.

Strathcona's common shares are publicly traded on the Toronto Stock Exchange under the symbol SCR.

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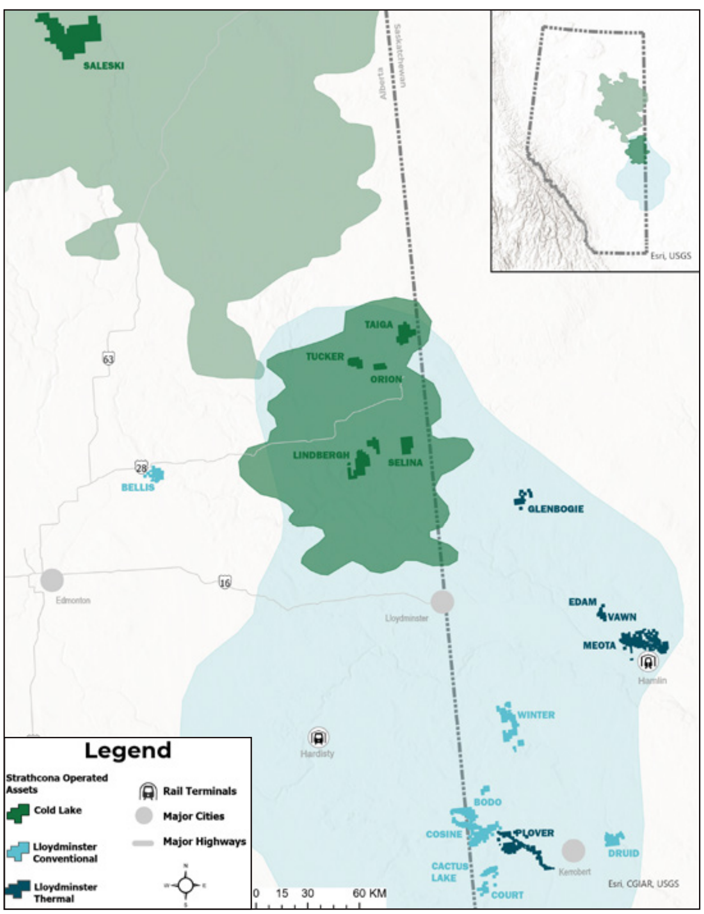

2025 Highlights

51 years

2P reserve life indtex
Strong, dependable production for decades to come

$1.2B

Capital spending on organic growth
Advancing high value projects while maintaining top tier returns

$10 per share

Special distribution delivered
Providing value to shareholders

0.55

Total recordable injury frequency
Prioritizing safe, reliable and responsible performance every day

MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE YEARS ENDED DECEMBER 31, 2025 AND 2024

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 March 11, 2026 and should be read in conjunction with the Company's audited consolidated financial statements (and related notes) as at and for the years ended December 31, 2025 and 2024 (the "**annual financial statements**"). The annual financial statements have been prepared in accordance with IFRS® Accounting Standards (the "**Accounting Standards**") as issued by the International Accounting Standards Board, in Canadian dollars, except where indicated otherwise. The annual financial statements and MD&A of Strathcona have been prepared by management, reviewed by the Audit Committee of the Company's Board of Directors and were approved by the Company's Board of Directors.

This MD&A contains forward-looking information; see "*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, in each case except when noted otherwise. All per unit figures are based on commodity sales volumes, net of blending. Sales volumes differ from production volumes 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) ("**ABCA**"). 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 (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 December 31, 2025 and the date of this MD&A, approximately 69.9% and 66.6%, respectively, of the Company's common shares, were owned by certain limited partnerships comprising Waterous Energy Fund (collectively, "**WEF**").

RECENT DEVELOPMENTS

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 Board of Directors has approved Strathcona's filing of an application with the Toronto Stock Exchange ("**TSX**") for a normal course issuer bid ("**NCIB**"). Once approved by the TSX, Strathcona may buyback up to 5% of its issued and outstanding shares (up to a maximum of approximately 10.7 million common shares of the Company) over a twelve month period.

On March 11, 2026, Strathcona acquired the remaining 50% working interest in the Selina property, located in the Cold Lake Thermal segment, along with additional surrounding lands, for total consideration of $23 million. Following the acquisition, Strathcona holds a 100% operated working interest in Selina.

FOURTH QUARTER TRANSACTION SUMMARY

MEG Energy Corp. Takeover Bid

Termination of Offer to Acquire MEG

On May 30, 2025, Strathcona formally commenced an offer (the "**Offer**") to acquire all of the issued and outstanding common shares ("**MEG Shares**") of MEG Energy Corp. ("**MEG**") not already owned by Strathcona. On October 10, 2025, Strathcona terminated the Offer as Strathcona determined that the conditions to the Offer were no longer capable of being satisfied as a result of MEG having entered into a revised definitive agreement with Cenovus Energy Inc. ("**Cenovus**") in respect of the arrangement to acquire all MEG Shares (the "**Cenovus-MEG Transaction**"). Prior to and throughout the duration of the Offer, Strathcona acquired 31.6 million MEG Shares.

On October 26, 2025, Strathcona, concurrently with Cenovus improving consideration under the Cenovus-MEG Transaction, entered into a voting support agreement with Cenovus (the "**Voting Support Agreement**") pursuant to which Strathcona had agreed to, among other things and subject to the terms thereof, vote its 31.6 million of MEG Shares in favor of the Cenovus-MEG Transaction at the special meeting of holders of MEG Shares ("**MEG Shareholders**"). Concurrently with entering into the Voting Support Agreement, Strathcona also agreed to purchase from Cenovus the Vawn thermal project and certain undeveloped thermal lands at Lindbergh, Plover Lake and Glenbogie (the "**Vawn Acquisition**"), for initial consideration paid on closing of $71 million, after closing adjustments, and additional contingent consideration of up to $75 million, depending on future commodity prices, to be paid in accordance with the asset purchase agreement. See the "*Acquisitions*" section of this MD&A.

On December 22, 2025, Strathcona announced that it has disposed of its entire marketable security portfolio (including its MEG Shares and common shares of Cenovus through the Cenovus-MEG Transaction and its common shares of Tourmaline Oil Corp. ("**Tourmaline**") it had received pursuant to the Groundbirch Asset Sale) in late November 2025 and early December 2025 for total cash proceeds of approximately $1.39 billion.

Subscription Receipts

In connection with the Offer, on June 27, 2025, the Company, upon approval of the special committee of the board of directors of the Company comprised solely of independent directors, entered into a subscription receipt agreement with certain limited partnerships comprising Waterous Energy Fund III ("**WEF III**"), which are affiliated with WEF and a related party of the Company, under which 21.4 million subscription receipts of the Company were issued to WEF III at a price of $30.92 per subscription receipt, for aggregate gross proceeds of $662 million (the "**Subscription Receipt Agreement**"). Under the terms of the Subscription Receipt Agreement, the aggregate proceeds from the issuance of the subscription receipts were placed in escrow. Also under the terms of the Subscription Receipt Agreement, the Company was obligated to make a dividend equivalent payment ("**DEP**") to WEF III in the event that dividends were declared on the Common Shares prior to either their conversion to Common Shares or termination of the subscription receipts.

The termination of the Offer resulted in a corresponding termination of the Subscription Receipt Agreement, as such the proceeds held in escrow were returned to WEF III and the $13 million DEP was paid to WEF III.

Special Distribution

On December 22, 2025, Strathcona completed a $10.00 per share distribution to shareholders, or $2.14 billion in aggregate, with such amount derived from the cash proceeds received from the Kakwa and Grande Prairie Asset Sales (the "**Special Distribution**"), as part of a statutory plan of arrangement under Section 193 of the ABCA that entitled shareholders to receive the payment as a dividend or, at their election, a return of capital.

GUIDANCE

The following table sets forth production and capital expenditures guidance for 2026:

	2026 Guidance
Annual average production (Mboe/d)	**120 - 130**
Capital expenditures ($ millions)	**1,000**

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 represents 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. 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 and year ended December 31, 2025 and December 31, 2024, 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 December 31, 2025 Continuing	Discontinued	Total	Three Months Ended December 31, 2024[1] Continuing	Discontinued	Total
Revenues and other income						
Oil and natural gas sales	937	—	**937**	1,043	250	**1,293**
Sale of purchased products	14	—	**14**	16	—	**16**
Royalties	(99)	—	**(99)**	(185)	(24)	**(209)**
Oil and natural gas revenues	852	—	**852**	874	226	**1,100**
(Loss) gain on risk management contracts	(1)	—	**(1)**	10	—	**10**
Midstream revenue	8	—	**8**	—	—	**—**
Other income	2	—	**2**	—	—	**—**
	861	—	**861**	884	226	**1,110**
Expenses						
Purchased product	15	—	**15**	16	—	**16**
Blending costs	236	—	**236**	268	—	**268**
Production and operating	163	(8)	**155**	152	46	**198**
Transportation and processing	95	—	**95**	88	56	**144**
General and administrative	24	—	**24**	21	7	**28**
Interest	24	—	**24**	39	—	**39**
Transaction related costs	25	8	**33**	—	—	**—**
Finance costs	15	—	**15**	12	9	**21**
Depletion, depreciation and amortization	152	—	**152**	141	55	**196**
Impairment	376	—	**376**	—	—	**—**
Foreign exchange (gain) loss	(11)	—	**(11)**	48	—	**48**
Change in decommissioning liabilities	(13)	—	**(13)**	—	—	**—**
	1,101	—	**1,101**	785	173	**958**
Gain on marketable securities	102	—	**102**	—	—	**—**
Loss on sale of assets, net	—	(12)	**(12)**	—	—	**—**
(Loss) income before income taxes	(138)	(12)	**(150)**	99	53	**152**
Income tax (recovery) expense	(48)	(3)	**(51)**	49	15	**64**
(Loss) income and comprehensive (loss) income	(90)	(9)	**(99)**	50	38	**88**

(1) Comparative periods have been revised to reflect current period presentation, see the "*Discontinued Operations*" section of this MD&A.

($ millions, unless otherwise indicated)	Year Ended December 31, 2025 Continuing	Discontinued	Total	Year Ended December 31, 2024[1] Continuing	Discontinued	Total
Revenues and other income						
Oil and natural gas sales	4,096	521	**4,617**	4,373	963	**5,336**
Sale of purchased product	67	—	**67**	75	—	**75**
Royalties	(435)	(35)	**(470)**	(567)	(96)	**(663)**
Oil and natural gas revenues	3,728	486	**4,214**	3,881	867	**4,748**
Loss on risk management contracts	(86)	—	**(86)**	(44)	—	**(44)**
Midstream revenue	24	—	**24**	—	—	**—**
Other income	16	—	**16**	—	—	**—**
	3,682	486	**4,168**	3,837	867	**4,704**
Expenses						
Purchased product	68	—	**68**	75	—	**75**
Blending costs	1,034	—	**1,034**	1,081	—	**1,081**
Production and operating	672	76	**748**	641	171	**812**
Transportation and processing	368	111	**479**	364	213	**577**
General and administrative	88	10	**98**	76	25	**101**
Interest	131	—	**131**	170	—	**170**
Transaction related costs	44	27	**71**	1	—	**1**
Finance costs	56	13	**69**	50	38	**88**
Depletion, depreciation and amortization	607	90	**697**	595	279	**874**
Impairment	376	—	**376**	—	—	**—**
Foreign exchange (gain) loss	(34)	—	**(34)**	68	—	**68**
Change in decommissioning liabilities	(13)	—	**(13)**	—	—	**—**
	3,397	327	**3,724**	3,121	726	**3,847**
Gain on marketable securities	171	—	**171**	—	—	**—**
Gain on sale of assets, net	—	609	**609**	—	—	**—**
Loss on settlement of other obligations	—	(1)	**(1)**	—	(4)	**(4)**
Income before income taxes	456	767	**1,223**	716	137	**853**
Income tax expense	90	222	**312**	209	40	**249**
Income and comprehensive income	366	545	**911**	507	97	**604**

(1) Comparative periods have been revised to reflect current period presentation, see the "*Discontinued Operations*" section of this MD&A.

The following table reconciles the total operating earnings.

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2025**	Three Months Ended December 31, 2024[(1)]	Year Ended **December 31, 2025**	Year Ended December 31, 2024[(1)]
Revenues				
Oil and natural gas sales	**937**	1,293	**4,617**	5,336
Sale of purchased product	**14**	16	**67**	75
Blending costs	**(236)**	(268)	**(1,034)**	(1,081)
Purchased product	**(15)**	(16)	**(68)**	(75)
Midstream revenue	**8**	—	**24**	—
Oil and natural gas sales, net of blending	**708**	1,025	**3,606**	4,255
Expenses				
Royalties	**99**	209	**470**	663
Production and operating	**155**	198	**748**	812
Transportation and processing	**95**	144	**479**	577
Field operating income	**359**	474	**1,909**	2,203
Depletion, depreciation and amortization	**152**	196	**697**	874
General and administrative	**24**	28	**98**	101
Finance costs	**15**	21	**69**	88
Other income	**(2)**	—	**(16)**	—
Interest	**24**	39	**131**	170
Operating earnings	**146**	190	**930**	970

(1) Comparative periods have been revised to reflect current period presentation, see the "*Discontinued Operations*" section of this MD&A.

PRODUCTION VOLUMES

	Three Months Ended			Year Ended	
	December 31, 2025	December 31, 2024[1]	September 30, 2025	**December 31, 2025**	December 31, 2024[1]
Bitumen (bbl/d)	**62,538**	59,732	61,157	**61,327**	59,516
Heavy oil (bbl/d)	**54,660**	50,997	53,943	**52,658**	51,107
Condensate and light oil (bbl/d)	**57**	64	39	**59**	42
Total oil production (bbl/d)	**117,255**	110,793	115,139	**114,044**	110,665
Other NGLs (bbl/d)	**16**	4	4	**16**	2
Natural gas (mcf/d)	**2,444**	1,295	2,642	**2,750**	1,232
Total (boe/d) - continuing operations	**117,679**	111,013	115,584	**114,519**	110,873
Total (boe/d) - discontinued operations	**36**	76,190	617	**37,644**	72,207
Total (boe/d)	**117,715**	187,203	116,201	**152,163**	183,080
% liquids - continuing operations	**99.7 %**	99.8 %	99.6 %	**99.6 %**	99.8 %

(1) Comparative periods have been revised to reflect current period presentation, see the "*Discontinued Operations*" section of this MD&A.

Production volumes from continuing operations increased 6% (or 6,666 boe per day) for the three months ended December 31, 2025 to an average of 117,679 boe per day compared to 111,013 boe per day for the same period of 2024. The increase was primarily due to the performance of new wells drilled in the Cold Lake and Lloydminster Thermal segments and production added from the Vawn Acquisition. These increases were partially offset by a decline in the Lloydminster Conventional segment's production and unplanned downtime for pipeline maintenance in the Cold Lake segment.

Production volumes from continuing operations increased 3% (or 3,646 boe per day) for the year ended December 31, 2025 to an average of 114,519 boe per day compared to 110,873 boe per day for the same period of 2024. The increase was primarily due to the performance of new wells drilled in the Cold Lake and Lloydminster Thermal segments and production added from the Vawn Acquisition, partially offset by a decline in the Lloydminster Conventional segment's production volumes and downtime for pipeline maintenance and a planned turnaround in the Cold Lake Thermal segment.

Production volumes from continuing operations increased 2% (or 2,095 boe per day) during the three months ended December 31, 2025 to an average of 117,679 boe per day compared to 115,584 boe per day for the three months ended September 30, 2025. The increase was primarily driven by the performance of new wells drilled in the Cold Lake segment and production added from the Vawn Acquisition, partially offset by unplanned downtime for pipeline maintenance in the Cold Lake segment.

SALES VOLUMES

	Three Months Ended			Year Ended	
	December 31, 2025	December 31, 2024[1]	September 30, 2025	**December 31, 2025**	December 31, 2024[1]
Bitumen (bbl/d)	**62,579**	59,796	61,433	**61,307**	59,491
Heavy oil (bbl/d)	**53,260**	47,850	53,319	**52,922**	50,848
Condensate and light oil (bbl/d)	**57**	64	39	**59**	42
Total oil production (bbl/d)	**115,896**	107,710	114,791	**114,288**	110,381
Other NGLs (bbl/d)	**16**	4	4	**16**	2
Natural gas (mcf/d)	**2,444**	1,295	2,642	**2,750**	1,232
Total (boe/d) - continuing operations	**116,319**	107,930	115,235	**114,763**	110,588
Total (boe/d) - discontinued operations	**36**	76,190	617	**37,644**	72,206
Total (boe/d)	**116,355**	184,120	115,852	**152,407**	182,794

(1) Comparative periods have been revised to reflect current period presentation, see the "*Discontinued Operations*" section of this MD&A.

Sales volumes typically trend with production volumes, except in cases of an inventory build or draw. Strathcona carries inventory on rail cars in transit to the US Gulf Coast, on pipelines and in storage tanks. For the full year 2025, there were no significant changes in inventory volumes; therefore, sales volumes closely approximated production volumes.

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
	December 31, 2025	December 31, 2024	September 30, 2025	**December 31, 2025**	December 31, 2024
Benchmark Pricing					
US$/bbl unless otherwise indicated					
WTI(1)	**59.14**	70.27	64.93	**64.81**	75.72
WCS Hardisty(2)	**47.94**	57.72	54.54	**53.67**	60.97
WCS USGC(3)	**55.63**	65.69	62.59	**61.74**	69.69
WTI-WCS Hardisty differential	**(11.20)**	(12.55)	(10.39)	**(11.14)**	(14.75)
WTI-WCS USGC differential	**(3.51)**	(4.58)	(2.34)	**(3.07)**	(6.03)
NYMEX-AECO differential (US$/MMbtu)(4)	**(2.03)**	(1.86)	(2.42)	**(2.23)**	(1.33)
Condensate differential(5)	**(2.13)**	0.39	(1.83)	**(1.44)**	(2.78)
Average Exchange rate (C$/US$)	**1.3949**	1.3992	1.3774	**1.3978**	1.3700
CAD$/bbl unless otherwise indicated					
WTI(1)	**82.50**	98.30	89.43	**90.65**	103.70
WCS Hardisty(2)	**66.89**	80.75	75.10	**75.06**	83.53
WCS USGC(3)	**77.61**	91.90	86.19	**86.35**	95.46
AECO 5A (C$/gj)(6)	**2.11**	1.40	0.60	**1.59**	1.38
Condensate par at Edmonton	**79.54**	98.85	86.91	**88.62**	99.92
AESO weighted average pool price (C$/MWh)(7)	**43.66**	53.10	53.80	**44.98**	64.54
CORRA (%)(8)	**2.34**	3.83	2.74	**2.72**	4.59

(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 fourth quarter of 2025, WTI pricing averaged US$59.14 per bbl, a 9% decrease from the third quarter of 2025. The primary reason for this price decrease was macroeconomic resistance and weaker demand conditions caused by slowing industrial activity in major consuming regions. However, ongoing geopolitical uncertainty did provide some upside due to concerns about potential supply disruptions which impact global inventory levels. At the end of the fourth quarter of 2025, global inventory levels were sufficient to meet seasonal demand.

The WTI-WCS Hardisty differential widened relative to WTI by 8% in the fourth quarter of 2025, when compared to the third quarter of 2025. This was attributed to the reduction in refinery demand in the U.S. Midwest and Gulf Coast, and increasing apportionment on the Enbridge Mainline, as Canadian heavy crude production increased. Sufficient egress supported by the Trans Mountain pipeline aided in maintaining a narrow differential throughout 2025.

The WTI-WCS USGC differential widened relative to WTI by 50% in the fourth quarter of 2025, when compared to the third quarter of 2025. This was attributed to the reduced demand for Canadian heavy-crude from Gulf Coast refineries, caused by an increase in heavy supply sources for crude oil globally.

AECO 5A natural gas prices increased in the fourth quarter of 2025 by 252%, when compared to the third quarter of 2025, primarily due to the increase in winter seasonal demand and reduced storage injections. Lower pricing in the third quarter of 2025, as the result of oversupply and mild weather, rebounded in the fourth quarter of 2025.

REVENUE AND REALIZED PRICES

Oil and Natural Gas Sales – Net of Blending

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2025**	December 31, 2024[1]	September 30, 2025	Year Ended **December 31, 2025**	December 31, 2024[1]
Bitumen blend	**549**	632	586	**2,405**	2,576
Heavy oil, blended and raw	**387**	411	423	**1,688**	1,796
Condensate and light oil	**—**	—	—	**1**	1
Natural gas	**1**	—	—	**2**	—
Midstream revenue	**8**	—	9	**24**	—
Oil and natural gas sales	**945**	1,043	1,018	**4,120**	4,373
Loss on purchased product	**(1)**	—	—	**(1)**	—
Bitumen – blending cost	**(200)**	(233)	(194)	**(883)**	(930)
Heavy oil – blending cost	**(36)**	(35)	(28)	**(151)**	(151)
Oil and natural gas sales, net of blending - continuing operations[2]	**708**	775	796	**3,085**	3,292
Oil and natural gas sales, net of blending - discontinued operations[2]	**—**	250	3	**521**	963
Oil and natural gas sales, net of blending[2]	**708**	1,025	799	**3,606**	4,255

(1) Comparative periods have been revised to reflect current period presentation, see the "*Discontinued Operations*" section of this MD&A.
(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 9% (or $67 million) for the three months ended December 31, 2025 to $708 million compared to $775 million in the same period of 2024. Oil and natural gas sales, net of blending, from continuing operations decreased 6% (or $207 million) for the year ended December 31, 2025 to $3,085 million compared to $3,292 million for the same period in 2024. Oil and natural gas sales, net of blending from continuing operations decreased 11% (or $88 million) for the three months ended December 31, 2025 to $708 million compared to $796 million in the three months ended September 30, 2025. These decreases were primarily due to weaker oil benchmark pricing, and were partially offset by higher sales volumes, reduced blending costs due to lower condensate benchmark pricing and revenue from the acquired Hardisty Rail Terminal ("**HRT**").

Average Realized Prices

($ millions, unless otherwise indicated)	Three Months Ended December 31, 2025	December 31, 2024(1)	September 30, 2025	Year Ended December 31, 2025	December 31, 2024(1)
Bitumen blend ($/bbl)(2)	**60.66**	72.62	69.32	**68.00**	75.61
Heavy oil, blended and raw ($/bbl)(2)	**71.71**	85.05	80.60	**79.58**	88.34
Condensate and light oil ($/bbl)	**—**	50.99	—	**65.50**	71.13
Realized oil ($/bbl)	**65.74**	78.16	74.53	**73.36**	81.50
Other natural gas liquids ($/bbl)	**—**	—	—	**24.64**	—
Natural gas ($/mcf)	**1.52**	0.84	1.12	**1.70**	1.33
Midstream revenue ($/bbl)	**0.75**	—	0.91	**0.58**	—
Combined ($/boe) - continuing operations	**66.27**	77.99	75.08	**73.70**	81.33
Combined ($/boe) - discontinued operations	**—**	35.72	58.34	**37.90**	36.44
Combined ($/boe)	**66.27**	60.49	74.97	**64.85**	63.60

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(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 and year ended December 31, 2025, combined realized price from continuing operations decreased 15% (or $11.72 per boe) and 9% (or $7.63 per boe), respectively, compared to the same periods of 2024. These decreases were primarily due to lower average WTI benchmark prices, partially offset by narrower WCS Hardisty and USGC differentials, and lower condensate pricing, which reduced per barrel blend costs.

Combined realized price from continuing operations decreased 12% (or $8.81 per boe) for the three months ended December 31, 2025 compared to the three months ended September 30, 2025. This decrease was primarily due to lower average benchmark pricing and higher per barrel blend costs as the result of colder weather, partially offset by a reduction in condensate benchmark pricing.

ROYALTIES

($ millions, unless otherwise indicated)	Three Months Ended December 31, 2025	December 31, 2024(1)	September 30, 2025	Year Ended December 31, 2025	December 31, 2024(1)
Crown royalties	**81**	166	107	**348**	436
Freehold royalties	**5**	7	6	**23**	30
Gross overriding royalties	**8**	10	9	**41**	79
Other royalties	**5**	2	6	**23**	22
Royalties - continuing operations	**99**	185	128	**435**	567
Royalties - discontinued operations	**—**	24	—	**35**	96
Royalties	**99**	209	128	**470**	663
Effective royalty rate (%) - continuing operations(2)	**14.0 %**	23.9 %	16.0 %	**14.1 %**	17.2 %

(1) Comparative periods have been revised to reflect current period presentation, see the "*Discontinued Operations*" section of this MD&A.
(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 and year ended December 31, 2025, the effective royalty rate from continuing operations decreased to 14.0% and 14.1%, respectively, from 23.9% and 17.2% in the comparable periods in 2024. For the three months ended December 31, 2025, the effective royalty rate decreased to 14.0%, compared to 16.0% for the three months ended September 30, 2025. These decreases were primarily the result of lower crown royalty rates due to decreased average commodity prices.

PRODUCTION AND OPERATING EXPENSES

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2025**	December 31, 2024[1]	September 30, 2025	**December 31, 2025**	December 31, 2024[1]
Production and operating – Energy	**66**	57	38	**237**	241
Production and operating – Non-energy	**97**	95	107	**435**	400
Production and operating expenses - continuing operations	**163**	152	145	**672**	641
Production and operating expenses - discontinued operations	**(8)**	46	(4)	**76**	171
Production and operating expenses	**155**	198	141	**748**	812
Production and operating – Energy - continuing operations ($/boe)	**6.26**	5.69	3.65	**5.67**	5.95
Production and operating – Non-energy - continuing operations ($/boe)	**9.03**	9.51	10.09	**10.38**	9.87
Production and operating expenses - continuing operations ($/boe)	**15.29**	15.20	13.74	**16.05**	15.82

(1) Comparative periods have been revised to reflect current period presentation, see the "*Discontinued Operations*" section of this MD&A.

Production and operating expenses from continuing operations increased 7% (or $11 million) for the three months ended December 31, 2025 to $163 million ($15.29 per boe) from $152 million ($15.20 per boe) in the same period of 2024. Energy expenses increased by 16% (or $9 million) primarily due to the increase in fuel costs as the result of higher benchmark prices, partially offset by the purchase of carbon credits, which lowered the Company's initial estimate of the carbon tax burden compared to legislated rates. Non-energy expenses increased by 2% (or $2 million) primarily due to the acquisition of HRT, partially offset by lower chemical costs.

Production and operating expenses from continuing operations increased 5% (or $31 million) for the year ended December 31, 2025 to $672 million ($16.05 per boe) from $641 million ($15.82 per boe) in the same period of 2024. Energy expenses decreased by 2% (or $4 million) primarily due to the purchase of carbon credits, which lowered the Company's initial estimate of the carbon tax burden compared to legislated rates, partially offset by an increase in fuel costs due to higher benchmark prices. Non-energy expenses increased 9% (or $35 million) primarily due to the addition of HRT, greater surface maintenance costs due to integrity work, boiler repairs and maintenance performed on the evaporator at the Cold Lake segment and turnaround activities at the Lloydminster Conventional segment, and higher downhole expenses, partially offset by lower chemical costs.

Production and operating expenses from continuing operations increased 12% (or $18 million) for the three months ended December 31, 2025 to $163 million ($15.29 per boe) from $145 million ($13.74 per boe) for the three months ended September 30, 2025. Energy expenses increased 74% (or $28 million) primarily due to increased fuel costs as the result of higher benchmark prices. Non-energy expenses decreased 9% (or $10 million) primarily due to a decrease in chemical expenses and a reduction in surface maintenance performed during colder months.

TRANSPORTATION EXPENSES

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2025**	December 31, 2024[(1)]	September 30, 2025	**December 31, 2025**	December 31, 2024[(1)]
Transportation expenses - continuing operations	**95**	88	92	**368**	364
Transportation and processing expenses - discontinued operations	**—**	56	—	**111**	213
Transportation and processing expenses	**95**	144	92	**479**	577
$ per boe - continuing operations	**8.75**	8.91	8.67	**8.78**	8.99

(1) Comparative periods have been revised to reflect current period presentation, see the "*Discontinued Operations*" section of this MD&A.

Transportation expenses from continuing operations increased 8% (or $7 million) for the three months ended December 31, 2025 to $95 million ($8.75 per boe) compared to $88 million ($8.91 per boe) in the same period of 2024. This increase was primarily due to higher overall sales volumes and incremental pipeline costs associated with the Vawn Acquisition.

Transportation expenses from continuing operations increased 1% (or $4 million) for the year ended December 31, 2025 to $368 million ($8.78 per boe) compared to $364 million ($8.99 per boe) in the same period of 2024. This increase was primarily attributable to higher overall sales volumes, partially offset by a decrease in heavy oil trucking due to lower volumes in the Lloydminster Conventional segment.

Transportation expenses from continuing operations increased 3% (or $3 million) for the three months ended December 31, 2025 to $95 million ($8.75 per boe) from $92 million ($8.67 per boe) in the three months ended September 30, 2025. This increase was primarily due to higher overall sales volumes and timing of the utilization of pipeline make-up rights at the Cold Lake segment.

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

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2025**	December 31, 2024[(1)]	September 30, 2025	**December 31, 2025**	December 31, 2024[(1)]
Depletion expense	**142**	129	142	**569**	554
Depreciation and amortization expense	**10**	12	9	**38**	41
DD&A - continuing operations	**152**	141	151	**607**	595
DD&A - discontinued operations	**—**	55	—	**90**	279
DD&A	**152**	196	151	**697**	874
$ per boe - continuing operations	**14.23**	14.27	14.27	**14.49**	14.70

(1) Comparative periods have been revised to reflect current period presentation, see the "*Discontinued Operations*" section of this MD&A.

DD&A expense from continuing operations increased 8% (or $11 million) for the three months ended December 31, 2025 to $152 million ($14.23 per boe) compared to $141 million ($14.27 per boe) for the same period of 2024. DD&A expense from continuing operations increased 2% (or $12 million) for the year ended December 31, 2025 to $607 million ($14.49 per boe), compared to $595 million ($14.70 per boe) for the same period of 2024. These increases were primarily due to higher sales volumes.

DD&A expense from continuing operations remained consistent during the three months ended December 31, 2025 at $152 million ($14.23 per boe) compared to $151 million ($14.27 per boe) for the three months ended September 30, 2025.

Impairment

Oil and Natural Gas Properties

For the year ended December 31, 2025, the Company determined the recoverable amount of the Lloydminster Conventional cash generating unit ("**CGU**") to be lower than its carrying amount and therefore an impairment loss of $376 million was recorded in impairment expense. The impairment loss was primarily the result of low commodity prices and operating performance throughout 2025.

*Exploration and Evaluation ("**E&E**") Assets*

The Vawn Acquisition included undeveloped land in a pre-existing E&E area of the Company. The consolidation of these lands resulted in a reprioritization of existing lands versus acquired lands. While this change in development plan represents an indicator of impairment, the Company's assessment concluded that the recoverable amount of E&E assets continues to exceed its carrying amount.

GENERAL AND ADMINISTRATIVE EXPENSES ("G&A")

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2025**	December 31, 2024[(1)]	September 30, 2025	**December 31, 2025**	December 31, 2024[(1)]
G&A expenses - continuing operations	**24**	21	24	**88**	76
G&A expenses - discontinued operations	**—**	7	(2)	**10**	25
G&A expenses	**24**	28	22	**98**	101
$ per boe - continuing operations	**2.23**	2.15	2.23	**2.10**	1.88

(1) Comparative periods have been revised to reflect current period presentation, see the "*Discontinued Operations*" section of this MD&A.

For the three months and year ended December 31, 2025, G&A expenses from continuing operations increased 14% (or $3 million) and 16% (or $12 million), respectively, compared to the same periods of 2024. These increases were primarily due to the reallocation of corporate costs across the business following the sale of the Montney segment.

G&A expenses from continuing operations remained consistent at $24 million for the three months ended December 31, 2025 and September 30, 2025.

INTEREST

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2025**	December 31, 2024	September 30, 2025	**December 31, 2025**	December 31, 2024
Interest	**24**	39	23	**131**	170
Weighted average interest rate (%)	**6.3 %**	5.8 %	6.6 %	**5.9 %**	6.1 %

For the three months ended December 31, 2025, interest expense decreased 38% (or $15 million) to $24 million compared to $39 million in the same period of 2024. For the year ended December 31, 2025, interest expense decreased 23% (or $39 million) to $131 million compared to $170 million in the same period of 2024. These decreases were primarily due to lower debt levels following the receipt of the proceeds from the disposition of the Montney segment and lower interest rates, partially offset by reduced savings on interest rate swaps as the result of decreasing CORRA rates and greater standby fees due to excess capacity on the credit facility.

Interest expense remained consistent at $24 million for the three months ended December 31, 2025, compared to $23 million for the three months ended September 30, 2025.

During the year ended December 31, 2025, the Company recorded $48 million in interest expense on the Senior Notes (as defined in the "*Capital Resources*" section of this MD&A) (December 31, 2024 – $47 million), $81 million in interest expense on the Credit Facilities (as defined in the "*Capital Resources*" section of this MD&A) (December 31, 2024 - $146 million), and a realized loss of $2 million on interest rate swaps (December 31, 2024 - realized gain of $23 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 December 31, 2025, the Company had approximately $2,790 million (December 31, 2024 - $5,595 million) of tax pools available for deduction in future periods as shown in the table below.

($ millions, unless otherwise indicated)	Annual Pool Deduction Rate	**December 31, 2025**	December 31, 2024
Canadian oil and gas property expenditures(1)	10%	**254**	838
Canadian development expenditures(1)	30%	**165**	1,280
Canadian exploration expenditures(1)	100%	**3**	18
Undepreciated capital costs(2)	4% - 55%	**1,232**	1,503
Non-capital losses	100%	**897**	1,708
Other(3)		**239**	248
Total tax pools		**2,790**	5,595

(1) Amount is net of tax pools where deductibility is uncertain.
(2) As at December 31, 2025, approximately 91% (December 31, 2024 – 93%) 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.

MARKETABLE SECURITIES

Marketable securities represent equity interests in publicly traded companies that the Company acquired either through open market transactions, the completion of Cenovus-MEG Transaction or received as consideration in the Groundbirch Asset Sale. During the year ended December 31, 2025, the Company acquired marketable securities at an aggregate cost of $1,219 million. All such marketable securities were disposed of during 2025 for total cash proceeds of $1,390 million, resulting in a gain on marketable securities of $171 million (2024 – $nil). The Company also recognized dividend income of $16 million related to these investments in 2025 (2024 – $nil). No marketable securities were held as at December 31, 2025 (December 31, 2024 – $nil).

CAPITAL EXPENDITURES

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

($ millions, unless otherwise indicated)	Three Months Ended December 31, 2025	December 31, 2024	September 30, 2025	Year Ended December 31, 2025	December 31, 2024
Drilling, completion and equipping	**44**	171	107	**564**	674
Facilities and pipelines	**94**	173	147	**499**	456
Recompletion, workovers and polymer powder	**15**	34	16	**63**	107
Capitalized G&A and other expenditures	**23**	15	11	**60**	59
Capital expenditures(1)	**176**	393	281	**1,186**	1,296

(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 December 31, 2025	December 31, 2024	September 30, 2025	Year Ended December 31, 2025	December 31, 2024
Cold Lake	**86**	135	98	**371**	372
Lloydminster Thermal	**61**	85	143	**415**	260
Lloydminster Conventional	**35**	53	39	**164**	185
Corporate	**6**	7	1	**7**	9
Capital expenditures - continuing operations	**188**	280	281	**957**	826
Capital expenditures - discontinued operations	**(12)**	113	—	**229**	470
Capital expenditures	**176**	393	281	**1,186**	1,296

For the three months ended December 31, 2025, drilling, completion and equipping activities accounted for 25% of capital expenditures as the Company drilled 43 new wells during the fourth quarter of 2025; 10 in Cold Lake, 19 in Lloydminster Thermal and 14 in Lloydminster Conventional. For the year ended December 31, 2025, drilling, completion and equipping activities accounted for 48% of capital expenditures as the Company drilled 220 new wells during the year; 52 in Cold Lake, 91 in Lloydminster Thermal, 64 in Lloydminster Conventional and 13 in Montney. For the three months and year ended December 31, 2025, facilities and pipeline expenditures accounted for 53% and 42% of capital expenditures, respectively, and related primarily to the construction of the Meota Central processing facility, the turnaround at Tucker, a waste heat recovery project to generate power at Orion, and one-time steam generation expansion and debottlenecking at Lindbergh.

DECOMMISSIONING EXPENDITURES

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

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2025**	December 31, 2024	September 30, 2025	**December 31, 2025**	December 31, 2024
Alberta	**4**	5	2	**19**	10
British Columbia	**3**	5	4	**21**	19
Saskatchewan	**2**	3	2	**4**	7
Total decommissioning expenditures(1)	**9**	13	8	**44**	36

(1) Decommissioning expenditures includes continuing and discontinued operations.

ACQUISITIONS

Vawn Acquisition

On December 1, 2025, Strathcona completed the Vawn Acquisition for cash consideration of $71 million, including closing adjustments, and estimated contingent consideration of $33 million. Contingent consideration of $1 million is payable for each dollar per barrel the WCS Index averages above C$70.00 per barrel in a given quarter, payable quarterly over the 14-quarter period following the close of the transaction, up to a maximum of $75 million. Fair value was determined as the present value of expected future payments using forecast WCS prices, discounted at 10%.

The Vawn Acquisition is adjacent to Strathcona's existing Edam property within the Lloydminster Thermal segment and was producing 5,000 bbls/d at the time of completion of the acquisition. The results of the assets acquired pursuant to the Vawn Acquisition are included in the consolidated financial statements from the date of closing on December 1, 2025.

Hardisty Rail Terminal Acquisition

On April 4, 2025, the Company completed the acquisition of HRT for cash consideration of $48 million. HRT, located in Hardisty, Alberta, is the largest crude-by-rail terminal in Western Canada.

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	bbl/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 and the Senior Notes were denominated 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(1)	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(1)	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 December 31, 2025, refer to Note 18 in the annual financial statements.

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

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2025**	 December 31, 2024	 September 30, 2025	Year Ended **December 31, 2025**	 December 31, 2024
Loss on risk management contracts - realized	**75**	5	20	**100**	107
(Gain) loss on risk management contracts - unrealized	**(74)**	(15)	7	**(14)**	(63)
Total loss (gain) on risk management contracts	**1**	(10)	27	**86**	44
Realized loss on risk management contracts per boe[1]	**7.01**	0.32	1.86	**1.80**	1.60

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

Strathcona realized a loss on risk management contracts of $75 million for the three months ended December 31, 2025, compared to a loss of $5 million for the same period in 2024. The Company realized a loss on risk management contracts of $100 million in the year ended December 31, 2025, compared to a loss of $107 million for the same period in 2024. The realized losses are primarily due to a cost of US$43 million associated with the restructuring of WCS crude oil swaps and higher realized commodity benchmark prices in comparison to contracted hedge pricing. During the year ended December 31, 2024, the realized losses were due to the settlement of premiums associated with expired bought calls for non-cash consideration of $112 million, partially offset by cash settlement of gain positions on WTI crude oil contracts.

As at December 31, 2025, the mark-to-market value of risk management contracts was a net liability of $26 million (December 31, 2024 - net liability of $41 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 18 of the annual financial statements.

SEGMENT RESULTS

Segment disclosures reflect the manner in which Strathcona evaluates and allocates resources among the Company's principal operations.

During the year ended December 31, 2025, management reassessed the Company's operating segment structure in light of changes to its asset base, including the divestiture of the Montney segment and the Vawn Acquisition. As a result of this review, the Lloydminster segment was disaggregated into two segments: Lloydminster Thermal and Lloydminster Conventional, to reflect the Company's updated internal reporting and management structure. This change reflects differences in how the chief operating decision makers ("**CODMs**") evaluate performance and allocate resources.

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.

The Company reports activities not directly attributable to an operating segment under Corporate and Midstream, which includes HRT.

The following tables present the financial performance by reportable segment and include a measure of segment profit or loss regularly reviewed by the CODMs for the noted periods ended December 31, 2025 and 2024. Certain comparative information related to finance costs and general and administrative costs have been allocated by segment to conform with current period presentation. For the year ended December 31, 2024, Field Operating Earnings was used by the CODMs to evaluate segment profit or loss. Operating Earnings was used by the CODMs commencing for the period ended March 31, 2025.

See the "*Discontinued Operations*" section in this MD&A for information regarding the sale of the Company's Montney segment.

For the Three Months Ended ($ millions, unless otherwise indicated)	Cold Lake Segment			Lloydminster Thermal Segment[1]			Lloydminster Conventional Segment[1]			Corporate and Midstream			Consolidated[2]		
	Dec 31, 2025	Dec 31, 2024	Sep 30, 2025	**Dec 31, 2025**	Dec 31, 2024	Sep 30, 2025	**Dec 31, 2025**	Dec 31, 2024	Sep 30, 2025	**Dec 31, 2025**	Dec 31, 2024	Sep 30, 2025	**Dec 31, 2025**	Dec 31, 2024	Sep 30, 2025
Production volumes															
Bitumen (bbl/d)	**62,538**	59,732	61,157	**—**	—	—	**—**	—	—	**—**	—	—	**62,538**	59,732	61,157
Heavy oil (bbl/d)	**—**	—	—	**34,232**	26,236	31,937	**20,428**	24,761	22,006	**—**	—	—	**54,660**	50,997	53,943
Condensate and light oil (bbl/d)	**—**	—	—	**—**	—	—	**57**	64	39	**—**	—	—	**57**	64	39
Other NGLs (bbl/d)	**—**	—	—	**—**	—	—	**16**	4	4	**—**	—	—	**16**	4	4
Natural gas (mcf/d)	**—**	—	—	**—**	—	—	**2,444**	1,295	2,642	**—**	—	—	**2,444**	1,295	2,642
Production volumes (boe/d)	**62,538**	59,732	61,157	**34,232**	26,236	31,937	**20,908**	25,045	22,489	**—**	—	—	**117,679**	111,013	115,584
Sales volumes (boe/d)	**62,579**	59,796	61,433	**33,052**	22,640	30,941	**20,688**	25,494	22,861	**—**	—	—	**116,319**	107,930	115,235
Segment revenues															
Oil and natural gas sales	**549**	632	586	**243**	195	247	**144**	216	176	**1**	—	—	**937**	1,043	1,009
Sale of purchased products	**2**	—	6	**—**	—	—	**4**	6	9	**8**	10	16	**14**	16	31
Blending costs	**(200)**	(233)	(194)	**(10)**	(6)	(3)	**(26)**	(29)	(25)	**—**	—	—	**(236)**	(268)	(222)
Purchased product	**(2)**	—	(6)	**—**	—	—	**(4)**	(6)	(9)	**(9)**	(10)	(16)	**(15)**	(16)	(31)
Midstream revenue	**—**	—	—	**—**	—	—	**—**	—	—	**8**	—	9	**8**	—	9
Oil and natural gas sales, net of blending - continuing[3]	**349**	399	392	**233**	189	244	**118**	187	151	**8**	—	9	**708**	775	796
Segment expenses															
Royalties	**69**	133	86	**14**	27	22	**16**	25	20	**—**	—	—	**99**	185	128
Production and operating – Energy	**34**	30	19	**24**	19	13	**8**	8	6	**—**	—	—	**66**	57	38
Production and operating – Non-energy	**43**	50	48	**24**	17	22	**25**	28	32	**5**	—	5	**97**	95	107
Transportation	**22**	22	21	**66**	47	63	**7**	19	8	**—**	—	—	**95**	88	92
Field Operating Income - Continuing[3]	**181**	164	218	**105**	79	124	**62**	107	85	**3**	—	4	**351**	350	431
Depletion, depreciation and amortization	**44**	41	43	**63**	51	65	**42**	44	41	**3**	5	2	**152**	141	151
General and administrative	**9**	8	9	**8**	7	8	**7**	6	7	**—**	—	—	**24**	21	24
Finance costs	**1**	1	1	**1**	1	1	**—**	—	—	**13**	10	12	**15**	12	14
Other income	**—**	—	—	**—**	—	—	**—**	—	—	**(2)**	—	(8)	**(2)**	—	(8)
Interest	**—**	—	—	**—**	—	—	**—**	—	—	**24**	39	23	**24**	39	23
Operating Earnings - Continuing	**127**	114	165	**33**	20	50	**13**	57	37	**(35)**	(54)	(25)	**138**	137	227
Impairment	**—**	—	—	**—**	—	—	**376**	—	—	**—**	—	—	**376**	—	—
Loss on risk management contracts - realized	**—**	—	—	**—**	—	—	**—**	—	—	**75**	5	20	**75**	5	20
(Gain) loss on risk management contracts - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**(74)**	(15)	7	**(74)**	(15)	7
Foreign exchange loss (gain) - realized	**—**	—	—	**—**	—	—	**—**	—	—	**54**	(3)	(2)	**54**	(3)	(2)
Foreign exchange (gain) loss - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**(65)**	51	19	**(65)**	51	19
Transaction related costs	**—**	—	—	**—**	—	—	**—**	—	—	**25**	—	4	**25**	—	4
Gain on marketable securities - realized	**—**	—	—	**—**	—	—	**—**	—	—	**(171)**	—	(22)	**(171)**	—	(22)
Loss on marketable securities - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**69**	—	—	**69**	—	—
Change in decommissioning liabilities	**—**	—	—	**—**	—	—	**—**	—	—	**(13)**	—	—	**(13)**	—	—
Deferred tax (recovery) expense	**—**	—	—	**—**	—	—	**—**	—	—	**—**	—	—	**(48)**	49	57
(Loss) income and comprehensive (loss) income from continuing operations													**(90)**	50	144
(Loss) income and comprehensive (loss) income from discontinued operations, net of tax													**(9)**	38	429
(Loss) income and comprehensive (loss) income													**(99)**	88	573

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For the Three Months Ended ($/boe)	Cold Lake Segment			Lloydminster Thermal Segment[1]			Lloydminster Conventional Segment[1]			Corporate and Midstream			Consolidated[2]		
	Dec 31, 2025	Dec 31, 2024	Sep 30, 2025	**Dec 31, 2025**	Dec 31, 2024	Sep 30, 2025	**Dec 31, 2025**	Dec 31, 2024	Sep 30, 2025	**Dec 31, 2025**	Dec 31, 2024	Sep 30, 2025	**Dec 31, 2025**	Dec 31, 2024	Sep 30, 2025
Segment revenues															
Oil and natural gas sales	**66.93**	80.88	75.05	**76.70**	91.38	85.92	**66.88**	82.84	74.00	**—**	0.03	—	**69.22**	83.11	77.48
Sale of purchased products	**0.37**	—	0.96	**—**	—	—	**2.40**	2.41	4.23	**0.82**	1.01	1.56	**1.45**	1.58	2.37
Blending costs	**(6.28)**	(8.26)	(5.72)	**(0.22)**	(0.31)	(0.05)	**(4.28)**	(3.91)	(2.60)	**—**	—	—	**(3.69)**	(5.08)	(3.27)
Purchased product	**(0.36)**	—	(0.97)	**—**	—	—	**(2.39)**	(2.43)	(4.26)	**(0.84)**	(1.04)	(1.60)	**(1.46)**	(1.62)	(2.41)
Midstream revenue	**—**	—	—	**—**	—	—	**—**	—	—	**0.75**	—	0.91	**0.75**	—	0.91
Oil and natural gas sales, net of blending - continuing[3]	**60.66**	72.62	69.32	**76.48**	91.07	85.87	**62.61**	78.91	71.37	**0.73**	—	0.87	**66.27**	77.99	75.08
Segment expenses															
Royalties	**12.10**	24.16	15.25	**4.67**	12.91	7.55	**7.87**	10.75	9.43	**—**	—	—	**9.23**	18.63	12.03
Production and operating – Energy	**6.05**	5.44	3.34	**8.06**	9.25	4.54	**4.03**	3.16	3.26	**—**	—	—	**6.26**	5.69	3.65
Production and operating – Non-energy	**7.51**	9.11	8.67	**7.83**	8.01	7.78	**12.86**	11.85	14.89	**0.48**	—	0.43	**9.03**	9.51	10.09
Transportation	**3.84**	4.05	3.75	**21.50**	22.78	22.38	**3.39**	8.06	3.24	**(0.02)**	—	0.02	**8.75**	8.91	8.67
Field Operating Netback - Continuing[3]	**31.16**	29.86	38.31	**34.42**	38.12	43.62	**34.46**	45.09	40.55	**0.27**	—	0.42	**33.00**	35.25	40.64
Depletion, depreciation and amortization	**7.73**	7.22	7.55	**20.87**	24.53	22.78	**21.76**	19.70	19.63	**0.26**	0.47	0.23	**14.23**	14.27	14.27
General and administrative	**1.49**	1.44	1.53	**2.64**	3.65	2.83	**3.79**	2.45	2.67	**—**	—	—	**2.23**	2.15	2.23
Finance costs	**0.13**	0.18	0.15	**0.19**	0.46	0.24	**0.02**	0.02	0.02	**1.29**	1.05	1.12	**1.42**	1.25	1.27
Other income	**—**	—	—	**—**	—	—	**—**	—	—	**(0.13)**	(0.01)	(0.76)	**(0.13)**	(0.01)	(0.76)
Interest	**—**	—	—	**—**	—	—	**—**	—	—	**2.16**	3.93	2.18	**2.16**	3.93	2.18
Operating Earnings - Continuing	**21.81**	21.02	29.08	**10.72**	9.48	17.77	**8.89**	22.92	18.23	**(3.31)**	(5.44)	(2.35)	**13.09**	13.66	21.45
Effective royalty rate (%)[3]	**19.8**	33.3	22.0	**6.0**	14.2	8.8	**13.6**	13.6	13.2	**—**	—	—	**14.0**	23.9	16.0

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For the Year Ended ($ millions, unless otherwise indicated)	Cold Lake Segment December 31, 2025	Cold Lake Segment December 31, 2024	Lloydminster Thermal Segment[1] December 31, 2025	Lloydminster Thermal Segment[1] December 31, 2024	Lloydminster Conventional Segment[1] December 31, 2025	Lloydminster Conventional Segment[1] December 31, 2024	Corporate and Midstream December 31, 2025	Corporate and Midstream December 31, 2024	Consolidated[2] December 31, 2025	Consolidated[2] December 31, 2024
Production volumes										
Bitumen (bbl/d)	**61,327**	59,516	**—**	—	**—**	—	**—**	—	**61,327**	59,516
Heavy oil (bbl/d)	**—**	—	**30,480**	27,310	**22,178**	23,797	**—**	—	**52,658**	51,107
Condensate and light oil (bbl/d)	**—**	—	**—**	—	**59**	42	**—**	—	**59**	42
Other NGLs (bbl/d)	**—**	—	**—**	—	**16**	2	**—**	—	**16**	2
Natural gas (mcf/d)	**—**	—	**—**	—	**2,750**	1,232	**—**	—	**2,750**	1,232
Production volumes (boe/d)	**61,327**	59,516	**30,480**	27,310	**22,712**	24,047	**—**	—	**114,519**	110,873
Sales volumes (boe/d)	**61,307**	59,491	**30,685**	27,026	**22,771**	24,071	**—**	—	**114,763**	110,588
Segment revenues										
Oil and natural gas sales	**2,405**	2,576	**982**	954	**708**	843	**1**	—	**4,096**	4,373
Sale of purchased product	**10**	18	**—**	—	**23**	26	**34**	31	**67**	75
Blending costs	**(883)**	(930)	**(28)**	(14)	**(123)**	(137)	**—**	—	**(1,034)**	(1,081)
Purchased product	**(10)**	(18)	**—**	—	**(23)**	(26)	**(35)**	(31)	**(68)**	(75)
Midstream revenue	**—**	—	**—**	—	**—**	—	**24**	—	**24**	—
Oil and natural gas sales, net of blending - continuing[3]	**1,522**	1,646	**954**	940	**585**	706	**24**	—	**3,085**	3,292
Segment expenses										
Royalties	**287**	385	**69**	86	**79**	96	**—**	—	**435**	567
Production and operating – Energy	**119**	128	**86**	80	**32**	33	**—**	—	**237**	241
Production and operating – Non-energy	**198**	196	**98**	85	**124**	119	**15**	—	**435**	400
Transportation	**86**	88	**253**	224	**29**	52	**—**	—	**368**	364
Field Operating Income - Continuing[3]	**832**	849	**448**	465	**321**	406	**9**	—	**1,610**	1,720
Depletion, depreciation and amortization	**168**	167	**251**	226	**175**	185	**13**	17	**607**	595
General and administrative	**33**	28	**29**	25	**26**	23	**—**	—	**88**	76
Finance costs	**3**	4	**3**	4	**1**	—	**49**	42	**56**	50
Other income	**—**	—	**—**	—	**—**	—	**(16)**	—	**(16)**	—
Interest	**—**	—	**—**	—	**—**	—	**131**	170	**131**	170
Operating Earnings - Continuing	**628**	**650**	**165**	**210**	**119**	198	**(168)**	(229)	**744**	829
Impairment	**—**	—	**—**	—	**376**	—	**—**	—	**376**	—
Loss on risk management contracts - realized	**—**	—	**—**	—	**—**	—	**100**	107	**100**	107
Gain on risk management contracts - unrealized	**—**	—	**—**	—	**—**	—	**(14)**	(63)	**(14)**	(63)
Foreign exchange loss - realized	**—**	—	**—**	—	**—**	—	**56**	—	**56**	—
Foreign exchange (gain) loss - unrealized	**—**	—	**—**	—	**—**	—	**(90)**	68	**(90)**	68
Transaction related costs	**—**	—	**—**	—	**—**	—	**44**	1	**44**	1
Gain on marketable securities - realized	**—**	—	**—**	—	**—**	—	**(171)**	—	**(171)**	—
Change in decommissioning liabilities	**—**	—	**—**	—	**—**	—	**(13)**	—	**(13)**	—
Deferred tax expense	**—**	—	**—**	—	**—**	—	**—**	—	**90**	209
Income and comprehensive income from continuing operations									**366**	507
Income and comprehensive income from discontinued operations, net of tax									**545**	97
Income and comprehensive income									**911**	**604**

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For the Year Ended ($/boe)	**Cold Lake Segment**		**Lloydminster Thermal Segment[1]**		**Lloydminster Conventional Segment[1]**		**Corporate and Midstream**		**Consolidated[2]**	
	December 31, 2025	December 31, 2024	**December 31, 2025**	December 31, 2024	**December 31, 2025**	December 31, 2024	**December 31, 2025**	December 31, 2024	**December 31, 2025**	December 31, 2024
Segment revenues										
Oil and natural gas sales	**75.00**	83.42	**85.30**	95.12	**75.20**	84.74	**0.01**	0.01	**77.29**	86.14
Sale of purchased products	**0.45**	0.84	**—**	—	**2.80**	2.95	**0.83**	0.76	**1.63**	1.85
Blending costs	**(6.99)**	(7.82)	**(0.13)**	(0.12)	**(4.64)**	(4.60)	**—**	—	**(4.15)**	(4.81)
Purchased product	**(0.46)**	(0.84)	**—**	—	**(2.81)**	(2.93)	**(0.84)**	(0.77)	**(1.65)**	(1.85)
Midstream revenue	**—**	—	**—**		**—**		**0.58**	—	**0.58**	—
Oil and natural gas sales, net of blending - continuing[3]	**68.00**	75.60	**85.17**	95.00	**70.55**	80.16	**0.58**	—	**73.70**	81.33
Segment expenses										
Royalties	**12.82**	17.69	**6.15**	8.64	**9.49**	10.93	**—**	—	**10.38**	14.01
Production and operating – Energy	**5.34**	5.87	**7.70**	8.09	**3.82**	3.72	**0.01**	—	**5.67**	5.95
Production and operating – Non-energy	**8.89**	9.00	**8.75**	8.60	**14.84**	13.47	**0.35**	—	**10.38**	9.87
Transportation	**3.85**	4.03	**22.55**	22.69	**3.48**	5.88	**—**	—	**8.78**	8.99
Field Operating Netback - Continuing[3]	**37.10**	39.01	**40.02**	46.98	**38.92**	46.16	**0.22**	—	**38.49**	42.51
Depletion, depreciation and amortization	**7.51**	7.67	**22.41**	22.79	**21.04**	21.07	**0.31**	0.42	**14.49**	14.70
General and administrative	**1.43**	1.28	**2.63**	2.56	**3.17**	2.62	**—**	—	**2.10**	1.88
Finance costs	**0.13**	0.16	**0.26**	0.42	**0.02**	0.01	**1.19**	1.04	**1.33**	1.23
Other income	**—**	—	**—**	—	**—**	—	**(0.37)**	—	**(0.37)**	—
Interest	**—**	—	**—**	—	**—**	—	**3.12**	4.20	**3.12**	4.20
Operating Earnings - Continuing	**28.03**	29.90	**14.72**	21.21	**14.69**	22.46	**(4.03)**	(5.66)	**17.82**	20.50
Effective royalty rate (%)[3]	**18.9**	23.4	**7.2**	9.1	**13.5**	13.6	**—**	—	**14.1**	17.2

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Cold Lake Segment

Production at the Cold Lake segment for the three months ended December 31, 2025 increased to 62,538 boe per day compared to 59,732 boe per day in the same period of 2024. For the year ended December 31, 2025, production increased to 61,327 boe per day, compared to 59,516 boe per day in the same period of 2024. These increases were primarily due to the performance of new Orion and Tucker wells drilled as part of the Company’s capital program, partially offset by an unplanned boiler outage and pipeline maintenance that impacted fuel gas availability at Lindbergh.

Oil and natural gas sales, net of blending, decreased to $349 million ($60.66 per boe) during the three months ended December 31, 2025 compared to $399 million ($72.62 per boe) for the same period of 2024. During the year ended December 31, 2025 oil and natural gas sales, net of blending, decreased to $1,522 million ($68.00 per boe) compared to $1,646 million ($75.60 per boe) for the same period of 2024. These decreases were primarily due to lower WCS Hardisty benchmark pricing, partially offset by higher sales volumes and reduced blending costs due to lower condensate benchmark pricing, compared to the same periods of 2024.

The effective royalty rate for the three months ended December 31, 2025 decreased to 19.8% from 33.3% in the same period of 2024. This decrease was the result of lower crown royalty rates due to lower average commodity prices and an increase in capital deductions. The effective royalty rate for the year ended December 31, 2025 decreased to 18.9% from 23.4% in the same period of 2024. This decrease was the result of lower crown royalty rates and a reduction in gross overriding royalties due to lower average commodity prices.

Energy related production and operating expenses for the three months ended December 31, 2025 increased to $34 million ($6.05 per boe) from $30 million ($5.44 per boe) in the same period in 2024. This increase was primarily due to increased fuel costs due to higher natural gas benchmark prices, partially offset by a reduction in utility costs from lower power benchmark prices and a decrease in carbon tax due to the purchase of carbon credits which reduced the Company's initial estimate of the carbon tax burden compared to legislated rates. During the year ended December 31, 2025 energy related production and operating expenses decreased to $119 million ($5.34 per boe) from $128 million ($5.87 per boe) in the same period of 2024. These decreases were primarily attributable to savings from the purchase of carbon credits, which lowered the Company's initial estimate of the carbon tax burden compared to legislated rates, partially offset by an increase in fuel costs due to higher natural gas benchmark prices.

Non-energy related production and operating expenses for the three months ended December 31, 2025 decreased to $43 million ($7.51 per boe) from $50 million ($9.11 per boe) in the same period in 2024. This decrease was primarily due to lower chemical costs, partially offset by increased instances of downhole maintenance performed in the current quarter. During the year ended December 31, 2025 non-energy related production and operating expenses increased to $198 million ($8.89 per boe) from $196 million ($9.00 per boe), for the same period of 2024. This increase was primarily attributable to higher surface maintenance costs, partially offset by lower chemical expenses.

For the three months ended December 31, 2025, transportation expenses remained consistent at $22 million ($3.84 per boe) compared to $22 million ($4.05 per boe) in the same period of 2024. For the year ended December 31, 2025, transportation expenses decreased to $86 million ($3.85 per boe) from $88 million ($4.03 per boe), in the same period of 2024. This decrease was primarily attributable to the timing and utilization of make-up rights.

Depletion, depreciation and amortization for the three months and year ended December 31, 2025 increased to $44 million ($7.73 per boe) and $168 million ($7.51 per boe), respectively, compared to $41 million ($7.22 per boe) and $167 million ($7.67 per boe) in the same periods of 2024. These increases were primarily due to higher sales volumes.

General and administrative for the three months ended December 31, 2025 increased to $9 million ($1.49 per boe) compared to $8 million ($1.44 per boe) in the same period of 2024. General and administrative for the year ended December 31, 2025 increased to $33 million ($1.43 per boe) compared to $28 million ($1.28 per boe) in the same period of 2024. These increases were primarily due to 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 December 31, 2025, increased to 34,232 boe per day compared to 26,236 boe per day in the same period of 2024. For the year ended December 31, 2025, production increased to 30,480 boe per day, compared to 27,310 boe per day in the same period of 2024. These increases were due to Meota East and Meota West wells brought on stream as part of the Company's capital program and the Vawn Acquisition.

Oil and natural gas sales, net of blending, increased to $233 million ($76.48 per boe) during the three months ended December 31, 2025 compared to $189 million ($91.07 per boe) for the same period of 2024. During the year ended December 31, 2025, oil and natural gas sales, net of blending, increased to $954 million ($85.17 per boe) compared to $940 million

($95.00 per boe) for the same period of 2024. These increases were primarily attributable to higher sales volumes, partially offset by lower WCS USGC benchmark prices.

The effective royalty rate for the three months and year ended December 31, 2025 decreased to 6.0% and 7.2%, respectively, compared to 14.2% and 9.1% in the same periods of 2024. These decreases primarily reflect lower average benchmark commodity prices and an increase in capital deductions.

Energy related production and operating expenses for the three months ended December 31, 2025 increased to $24 million ($8.06 per boe) compared to $19 million ($9.25 per boe) for the same period in 2024. This increase was primarily due to an increase in fuel costs due to higher natural gas benchmark prices and an increase in carbon tax expense as the result of an increase in production. Energy related production and operating expenses for the year ended December 31, 2025 increased to $86 million ($7.70 per boe) compared to $80 million ($8.09 per boe) for the same period in 2024. This increase was primarily due to an increase in fuel costs due to higher natural gas benchmark prices, partially offset by a reduction in carbon tax expense due to the utilization of internally generated carbon credits, which lowered the Company's initial estimate of the carbon tax burden compared to legislated rates.

Non-energy related production and operating expenses for the three months ended December 31, 2025 increased to $24 million ($7.83 per boe) compared to $17 million ($8.01 per boe) in the same period of 2024. This increase was primarily due to higher chemical costs, partially offset by a reduction in costs to operate the Hamlin Rail Terminal. Non-energy related production and operating expenses for the year ended December 31, 2025 increased to $98 million ($8.75 per boe), compared to $85 million ($8.60 per boe) for the same period in 2024. This increase was primarily due to higher downhole maintenance and chemical costs.

For the three months ended December 31, 2025, transportation expenses increased to $66 million ($21.50 per boe) compared to $47 million ($22.78 per boe) in the same period of 2024. For the year ended December 31, 2025, transportation expenses increased to $253 million ($22.55 per boe) from $224 million ($22.69 per boe) in the same period of 2024. These increases were primarily due to higher sales volumes.

Depletion, depreciation and amortization for the three months ended December 31, 2025 increased to $63 million ($20.87 per boe) compared to $51 million ($24.53 per boe) in the same period of 2024. Depletion, depreciation and amortization for the year ended December 31, 2025 increased to $251 million ($22.41 per boe) compared to $226 million ($22.79 per boe) in the same period of 2024. These increases were due to higher sales volumes, primarily at Meota West 2, partially offset by a higher proportion of sales volumes in areas with a lower depletion rates.

General and administrative for the three months ended December 31, 2025 increased to $8 million ($2.64 per boe) compared to $7 million ($3.65 per boe) in the same period of 2024. General and administrative for the year ended December 31, 2025 increased to $29 million ($2.63 per boe) compared to $25 million ($2.56 per boe) in the same period of 2024. These increases were primarily due to 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 December 31, 2025, decreased to 20,908 boe per day compared to 25,045 boe per day in the same period of 2024. For the year ended December 31, 2025, production decreased to 22,712 boe per day, compared to 24,047 boe per day in the same period of 2024. These decreases were due to temporary production curtailments, 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 $118 million ($62.61 per boe) during the three months ended December 31, 2025 compared to $187 million ($78.91 per boe) for the same period of 2024. Oil and natural gas sales, net of blending, decreased to $585 million ($70.55 per boe) during the year ended December 31, 2025 compared to $706 million ($80.16 per boe) for the same period of 2024. These decreases were primarily attributable to lower WCS Hardisty benchmark pricing and decreased sales volumes.

The effective royalty rate for the three months and year ended December 31, 2025 remained consistent at 13.6% and 13.5% compared to 13.6% and 13.6%, respectively, in the same periods of 2024.

Energy related production and operating expenses for the three months ended December 31, 2025 remained relatively consistent at $8 million ($4.03 per boe) compared to $8 million ($3.16 per boe) for the same period in 2024. During the year ended December 31, 2025 energy related production and operating expenses decreased to $32 million ($3.82 per boe) from $33 million ($3.72 per boe) for the same period in 2024. This decrease was primarily due to lower power costs.

Non-energy related production and operating expenses for the three months ended December 31, 2025 decreased to $25 million ($12.86 per boe) compared to $28 million ($11.85 per boe) in the same period of 2024. This decrease was primarily due to a portion of volumes being transported via rail in the comparable period of 2024, which requires additional chemical treating. Non-energy related production and operating expenses for the year ended December 31, 2025 increased to $124 million ($14.84 per boe) compared to $119 million ($13.47 per boe) for the same period in 2024. This increase was primarily due to higher labor costs.

For the three months ended December 31, 2025, transportation expenses decreased to $7 million ($3.39 per boe) compared to $19 million ($8.06 per boe) in the same period of 2024. For the year ended December 31, 2025, transportation expenses decreased to $29 million ($3.48 per boe) from $52 million ($5.88 per boe) in the same period of 2024. The reductions resulted from decreased rail transportation volumes, which incur higher costs per barrel relative to sales volumes transported by pipeline.

Depletion, depreciation and amortization for the three months ended December 31, 2025 decreased to $42 million ($21.76 per boe) compared to $44 million ($19.70 per boe) in the same period of 2024. Depletion, depreciation and amortization for the year ended December 31, 2025 decreased to $175 million ($21.04 per boe) compared to $185 million ($21.07 per boe) in the same period of 2024. These decreases were primarily due to lower sales volumes and a higher proportion of sales volumes from areas subject to lower depletion rates.

General and administrative for the three months ended December 31, 2025 increased to $7 million ($3.79 per boe) compared to $6 million ($2.45 per boe) in the same period of 2024. General and administrative for the year ended December 31, 2025 increased to $26 million ($3.17 per boe) compared to $23 million ($2.62 per boe) in the same period of 2024. These increases were primarily due to the reallocation of corporate costs across the business following the sale of the Montney segment.

Midstream

Strathcona's midstream operations is comprised of the wholly-owned HRT, 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 and year ended December 31, 2025 was $8 million ($0.75 per boe) and $24 million ($0.58 per boe), respectively. Non-energy related production and operating expenses associated with midstream operations, for the three months and year ended December 31, 2025, were $5 million ($0.48 per boe) and $15 million ($0.35 per boe), respectively.

DISCONTINUED OPERATIONS

Montney Asset Sales

During the year ended December 31, 2025, the Company completed the sale of its Montney segment. The Montney segment represents 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.* See "*Presentation of Continuing and Discontinued Operations*" section of this MD&A for additional information.

Historical results of the Montney segment presented as discontinued operations will not continue in future periods and are not indicative of the Company's future performance.

Financial performance and cash flow information

The following table summarizes the Company's financial results from discontinued operations:

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2025**	December 31, 2024	September 30, 2025	Year Ended **December 31, 2025**	December 31, 2024
Production volumes					
Condensate and light oil (bbl/d)	**8**	20,699	211	**10,280**	19,880
Other NGLs (bbl/d)	**10**	12,976	230	**6,035**	11,956
Natural gas (mcf/d)	**114**	255,091	1,059	**127,979**	242,224
Production volumes (boe/d)	**36**	76,190	617	**37,644**	72,207
Sales volumes (boe/d)	**36**	76,190	617	**37,644**	72,206
Revenues					
Condensate and light oil sales	**—**	180	2	**341**	704
Other NGLs sales	**—**	27	1	**57**	106
Natural gas sales	**—**	43	—	**123**	153
Oil and natural gas sales	**—**	250	3	**521**	963
Expenses					
Royalties	**—**	24	—	**35**	96
Production and operating - Energy	**(1)**	2	(1)	**—**	7
Production and operating - Non-energy	**(7)**	44	(3)	**76**	164
Transportation and processing	**—**	56	—	**111**	213
Field Operating Income - Discontinued[(1)]	**8**	124	7	**299**	483
Depletion, depreciation and amortization	**—**	55	—	**90**	279
General and administrative	**—**	7	(2)	**10**	25
Finance costs	**—**	9	—	**13**	38
Operating Earnings - Discontinued[(1)]	**8**	53	9	**186**	141
Effective royalty rate[(1)]	**—**	9.4 %	15.2 %	**6.7 %**	9.9 %

(1) 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.

The following table summarizes the cash flows from discontinued operations:

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2025**	December 31, 2024	September 30, 2025	Year Ended **December 31, 2025**	December 31, 2024
Cash flow from (used in) discontinued operations					
Operating activities	**1**	111	(6)	**260**	437
Financing activities	**—**	(10)	—	**(134)**	(198)
Investing activities	**12**	(113)	—	**(229)**	(470)
Change in cash from (used in) discontinued operations	**13**	(12)	(6)	**(103)**	(231)

CAPITAL RESOURCES

Bank Credit Facilities

Covenant-Based Revolving Credit Facility and Term Credit Facility

At December 31, 2025, the Company had a covenant-based revolving credit facility of $3.24 billion (December 31, 2024 - $2.5 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, 2024 - $nil) (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 December 31, 2025, the Company had letters of credit outstanding under the Revolving Credit Facility of $2 million (December 31, 2024 - $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 December 31, 2025 the cross-currency swap liability was $5 million (December 31, 2024 – an asset of $29 million) and total debt includes an unrealized gain of $5 million (December 31, 2024 – unrealized loss of $29 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 annual financial statements.

As at December 31, 2025, the Company had the following cross-currency interest rate swap contracts outstanding:

Notional (US$)	Maturity Date	Contract Price
825 million	January 26, 2026	CAD/USD 1.3778
175 million	January 29, 2026	CAD/USD 1.3775

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 December 31, 2025, the Company was in compliance with such financial covenants.

Senior Notes

On December 30, 2025, the Company redeemed its senior unsecured notes (the "**Senior Notes**") with an aggregate principal amount of US$500 million at 100% of par value. The Senior Notes bore interest at 6.875% per annum, payable semi-annually in arrears on February 1 and August 1, and were scheduled to mature on August 1, 2026.

Demand Letter of Credit Facility

As at December 31, 2025, the Company had a $200 million (December 31, 2024 - $100 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 December 31, 2025, the Company had letters of credit in the amount of $57 million (December 31, 2024 - $70 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, long-term 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	**December 31, 2025**	December 31, 2024
Revolving Credit Facility capacity	**3,240**	2,500
Term Credit Facility capacity[1]	**240**	—
Credit Facilities capacity	**3,480**	2,500
Credit Facilities debt[1]	**(2,116)**	(1,767)
Unrealized (gain) loss on U.S. borrowings	**(5)**	29
Letters of credit outstanding	**(2)**	(2)
Availability	**1,357**	760

(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 December 31, 2025, the working capital deficiency was $396 million (December 31, 2024 - $545 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 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 December 31, 2025.

	Total	<1 year	1-3 years	4-5 years	> 5 years
Credit Facilities[1]	**2,121**	—	—	2,121	—
Accounts payable and accrued liabilities	**619**	619	—	—	—
Risk management contract liability	**50**	21	29	—	—
Lease obligations[2]	**95**	33	25	10	27
Total	**2,885**	673	54	2,131	27

(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 December 31, 2025, the Company was committed to the following non-cancellable payments.

	Total	< 1 year	1-3 years	4-5 years	> 5 years
Transportation and processing	**2,646**	169	284	382	1,811
Capital	**175**	162	13	—	—
Other	**62**	48	13	1	—
Total	**2,883**	379	310	383	1,811

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

SHARE CAPITAL

The authorized capital of the Company consists of an unlimited number of common shares and an unlimited number of preferred shares. No preferred shares have been issued by the Company as at December 31, 2025 (December 31, 2024 – $nil).

The following table summarizes the number of shares outstanding as at March 11, 2026:

Share Class	Shares Outstanding at March 11, 2026
Common shares	214,235,608

Share Pass-through Transactions

On January 31, 2025, certain limited partnerships of WEF completed a share pass-through transaction that resulted in the disposition of 24,010,576 Strathcona common shares (the "**January Pass-through Transaction**"). Following the January Pass-through Transaction, WEF’s ownership of Strathcona's outstanding common shares decreased from approximately 90.8% to approximately 79.6%.

On November 7, 2025, one WEF limited partnership was dissolved, resulting in the disposition of 11,299,917 Strathcona common shares. Following this transaction, WEF's ownership of Strathcona’s outstanding common shares decreased from approximately 79.6% to approximately 74.3%.

On December 3, 2025, one WEF limited partnership completed a share pass-through transaction that resulted in the disposition of 9,529,013 Strathcona common shares (the "**December Pass-through Transaction**"). Following the December Pass-through Transaction, WEF's collective ownership of Strathcona’s outstanding common shares decreased from approximately 74.3% to approximately 69.9%.

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. Following the March Pass-through Transaction, WEF’s ownership of Strathcona’s outstanding common shares decreased from approximately 69.9% to approximately 66.6%.

Dividends

During the three months and year ended December 31, 2025, excluding the Special Distribution, Strathcona declared and paid total dividends of $64 million ($0.30 per common share) and $249 million ($1.16 per common share), respectively, (three months and year ended December 31, 2024 - $54 million ($0.25 per common share) and $107 million ($0.50 per common share)).

On March 11, 2026, the Strathcona Board of Directors declared a quarterly dividend of $0.30 per common share to be paid on March 27, 2026 to all shareholders of record on March 20, 2026.

RISK FACTORS

The Company’s business is subject to numerous risks and uncertainties, any of which may adversely affect the Company’s business and its financial results and results of its operations. Certain of these risks and uncertainties are described within this MD&A. For additional information refer to the "*Risk Factors*" section in our Annual Information Form for the year ended December 31, 2025, a copy of which may be accessed through the SEDAR+ website at www.sedarplus.ca.

Risks Relating to Strathcona's Business

Strathcona's exploration and production activities are concentrated in Alberta and Saskatchewan where activity is highly competitive and includes a variety of different-sized companies. Strathcona is subject to a number of risks that are common to other organizations involved in the oil and gas industry. Such risks include finding and developing oil and gas reserves at economic costs, estimating amounts of recoverable reserves, marketability of oil and gas produced, fluctuations in commodity prices, access to capital, financial and liquidity risks and environmental and safety risks.

Strathcona is exposed to market risk to the extent that the demand for oil and gas produced by the Company exists within Canada and the United States. External factors beyond the Company's control may affect the marketability of oil and gas produced. These factors include commodity prices and variations in the Canada-United States currency exchange rate which, in turn, responds to economic and political circumstances throughout the world. Oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals.

Exploration and production for oil and gas is capital intensive. Future capital expenditures may be financed in a variety of ways, including cash generated from operations, which fluctuates with changing commodity prices; borrowings, which exposes the Company to fluctuations in interest rates; and possible future equity offerings. Equity and debt capital are subject to market conditions, and availability and cost may increase or decrease from time to time.

Political and Social Events

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

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

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

Climate Change Risks

Strathcona's operations emit greenhouse gases ("**GHG**") which may require us to comply with federal and/or provincial GHG emissions legislation. Climate change policy is evolving at regional, national, and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate its effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, climate change has been linked to long-term shifts in climate patterns and extreme weather conditions, both of which pose the risk of causing operational difficulties.

SELECTED ANNUAL INFORMATION

($ millions, unless otherwise indicated)	Years Ended December 31, 2025	2024	2023
Oil and natural gas sales	**4,617**	5,336	4,749
Continuing operations	**4,096**	4,373	4,093
Discontinued operations	**521**	963	656
Net income	**911**	604	587
Continuing operations	**366**	507	396
Discontinued operations	**545**	97	191
Net income per share	**4.25**	2.82	2.94
Continuing operations	**1.71**	2.37	1.98
Discontinued operations	**2.54**	0.45	0.96
Total assets	**8,789**	10,978	10,497
Total non-current liabilities	**3,701**	4,028	4,103
Dividends per share	**1.16**	0.50	—
Special Distribution per share	**10.00**	—	—

SUMMARY OF QUARTERLY RESULTS

	2025				2024(1)			
($ millions, unless otherwise indicated)	**Q4**	Q3	Q2	Q1(1)	Q4	Q3	Q2	Q1
Operating results (boe/d)								
Average production volumes	**117,715**	116,201	181,368	194,609	187,203	178,235	181,766	185,122
Continuing operations	**117,679**	115,584	108,926	115,859	111,013	109,328	110,925	112,242
Discontinued operations	**36**	617	72,442	78,750	76,190	68,907	70,841	72,880
Financial Results								
Oil and natural gas sales	**937**	1,012	1,209	1,459	1,293	1,272	1,472	1,299
Continuing operations	**937**	1,009	974	1,176	1,043	1,059	1,231	1,041
Discontinued operations	**—**	3	235	283	250	213	241	258
Net (loss) income	**(99)**	573	231	206	88	188	227	100
Continuing operations	**(90)**	144	158	153	50	184	203	72
Discontinued operations	**(9)**	429	73	53	38	4	24	28
Net (loss) income per share	**(0.46)**	2.68	1.08	0.96	0.41	0.88	1.06	0.47
Continuing operations	**(0.42)**	0.68	0.74	0.71	0.23	0.86	0.95	0.34
Discontinued operations	**(0.05)**	2.00	0.34	0.25	0.18	0.02	0.11	0.13
Operating Earnings	**146**	236	226	322	190	265	306	209
Continuing operations	**138**	227	128	251	137	253	272	169
Discontinued operations(2)	**8**	9	98	71	53	12	34	40
Free Cash Flow(2)	**53**	94	32	185	(1)	201	247	158
Continuing operations(2)	**33**	85	44	169	1	105	247	51
Discontinued operations(2)	**20**	9	(12)	16	(2)	96	—	107
Capital expenditures(3)	**176**	281	379	350	393	320	298	286
Decommissioning expenditures(3)	**9**	8	3	24	13	9	3	12

(1) Comparative periods have been revised to reflect current period presentation, see the "*Discontinued Operations*" section of this MD&A.
(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 (loss) income 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 and sale of purchased product. 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 and sale 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.

"**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. A quantitative reconciliation of Field Operating Income and Field Operating Netback to the most directly comparable GAAP financial measure, Operating Earnings, is contained under the heading “*Segment Results*” and "*Discontinued Operations*" 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 annual 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 "*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 **December 31, 2025**	 December 31, 2024[1]	 September 30, 2025	Year Ended **December 31, 2025**	 December 31, 2024[1]
Operating Earnings - Continuing	**138**	137	227	**744**	829
Depletion, depreciation and amortization	**152**	141	151	**607**	595
Finance costs	**15**	12	14	**56**	50
Loss on risk management contracts - realized	**(75)**	(5)	(20)	**(100)**	(107)
Foreign exchange gain (loss) - realized, operating	**—**	3	2	**(2)**	—
Funds from Operations - Continuing	**230**	288	374	**1,305**	1,367
Capital expenditures	**(188)**	(280)	(281)	**(957)**	(826)
Decommissioning costs	**(9)**	(7)	(8)	**(42)**	(15)
Free Cash Flow - Continuing	**33**	1	85	**306**	526

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2025**	 December 31, 2024[1]	 September 30, 2025	Year Ended **December 31, 2025**	 December 31, 2024[1]
Operating Earnings - Discontinued	**8**	53	9	**186**	141
Depletion, depreciation and amortization	**—**	55	—	**90**	279
Finance costs	**—**	9	—	**13**	38
Realized loss on deferred premium settlement	**—**	—	—	**—**	112
Funds from Operations - Discontinued	**8**	117	9	**289**	570
Capital expenditures	**12**	(113)	—	**(229)**	(470)
Decommissioning costs	**—**	(6)	—	**(2)**	(21)
Free Cash Flow - Discontinued	**20**	(2)	9	**58**	79

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 **December 31, 2025**	 December 31, 2024[1]	 September 30, 2025	Year Ended **December 31, 2025**	 December 31, 2024[1]
Operating Earnings	**146**	190	236	**930**	970
Depletion, depreciation and amortization	**152**	196	151	**697**	874
Finance costs	**15**	21	14	**69**	88
Loss on risk management contracts - realized	**(75)**	(5)	(20)	**(100)**	(107)
Foreign exchange gain (loss) - realized, operating	**—**	3	2	**(2)**	—
Realized loss on deferred premium settlement	**—**	—	—	**—**	112
Funds from Operations	**238**	405	383	**1,594**	1,937
Capital expenditures	**(176)**	(393)	(281)	**(1,186)**	(1,296)
Decommissioning costs	**(9)**	(13)	(8)	**(44)**	(36)
Free Cash Flow	**53**	(1)	94	**364**	605

(1) Comparative periods have been revised to reflect current period presentation, see the "*Discontinued Operations*" section of this MD&A.

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 annual financial statements are discussed in Note 2 of the annual financial statements.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure controls and procedures ("**DC&P**"), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("**NI 52-109**"), are designed to provide reasonable assurance that information required to be disclosed in the Company's annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified under securities legislation and include controls and procedures designed to ensure that information required to be so disclosed is accumulated and communicated to management, including the Chief Commercial Officer together with the Chief Operating Officer in the capacity of Chief Executive Officer, and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Commercial Officer together with the Chief Operating Officer in the capacity of Chief Executive Officer, and the Chief Financial Officer of Strathcona evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's DC&P as at December 31, 2025. Based on that evaluation, the Chief Commercial Officer together with the Chief Operating Officer in the capacity of Chief Executive Officer, and the Chief Financial Officer concluded that Strathcona's DC&P were effective as at December 31, 2025.

Internal control over financial reporting ("**ICFR**") is a set of processes designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized, and facilitate the preparation of relevant, timely and reliable information. Because of its inherent limitations, ICFR may not prevent or detect misstatements. Management has assessed the effectiveness of the Company's ICFR as defined in Canada by NI 52-109. The assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organization of the Treadway Commission. Management concluded that the Company's ICFR was effective as of December 31, 2025. There were no changes made to the Company's ICFR during the year ended December 31, 2025 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR.

ADVISORIES REGARDING OIL & GAS INFORMATION

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

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. References to "liquids" 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 average daily production volumes for 2025 and 2024, 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:

	Three Months Ended			Year Ended	
	December 31, 2025	December 31, 2024[1]	September 30, 2025	**December 31, 2025**	December 31, 2024[1]
Cold Lake segment					
Heavy crude oil (bbl/d)	**—**	—	—	**—**	—
Light and medium crude oil (bbl/d)	**—**	—	—	**—**	—
Total crude oil (bbl/d)	**—**	—	—	**—**	—
Bitumen (bbl/d)	**62,538**	59,732	61,157	**61,327**	59,516
NGLs (bbl/d)	**—**	—	—	**—**	—
Total liquids (bbl/d)	**62,538**	59,732	61,157	**61,327**	59,516
Conventional natural gas (mcf/d)	**—**	—	—	**—**	—
Total (boe/d)	**62,538**	59,732	61,157	**61,327**	59,516
Lloydminster Thermal segment[2]					
Heavy crude oil (bbl/d)	**34,232**	26,236	31,937	**30,480**	27,310
Light and medium crude oil (bbl/d)	**—**	—	—	**—**	—
Total crude oil (bbl/d)	**34,232**	26,236	31,937	**30,480**	27,310
Bitumen (bbl/d)	**—**	—	—	**—**	—
NGLs (bbl/d)	**—**	—	—	**—**	—
Total liquids (bbl/d)	**34,232**	26,236	31,937	**30,480**	27,310
Conventional natural gas (mcf/d)	**—**	—	—	**—**	—
Total (boe/d)	**34,232**	26,236	31,937	**30,480**	27,310
Lloydminster Conventional segment[2]					
Heavy crude oil (bbl/d)	**20,428**	24,761	22,006	**22,178**	23,797
Light and medium crude oil (bbl/d)	**61**	64	1	**51**	42
Total crude oil (bbl/d)	**20,489**	24,825	22,007	**22,229**	23,839
Bitumen (bbl/d)	**—**	—	—	**—**	—
NGLs (bbl/d)	**12**	4	42	**25**	2
Total liquids (bbl/d)	**20,501**	24,829	22,049	**22,254**	23,841
Conventional natural gas (mcf/d)	**2,444**	1,295	2,642	**2,750**	1,232
Total (boe/d)	**20,908**	25,045	22,489	**22,712**	24,047
Discontinued operations					
Heavy crude oil (bbl/d)	**—**	—	—	**—**	—
Light and medium crude oil (bbl/d)	**—**	553	17	**212**	609
Total crude oil (bbl/d)	**—**	553	17	**212**	609
Bitumen (bbl/d)	**—**	—	—	**—**	—
NGLs (bbl/d)	**18**	33,122	424	**16,103**	31,227
Total liquids (bbl/d)	**18**	33,675	441	**16,315**	31,836
Conventional natural gas (mcf/d)	**114**	255,091	1,059	**127,979**	242,224
Total (boe/d)	**36**	76,190	617	**37,644**	72,207

(1) Comparative periods have been revised to reflect current period presentation, see the "*Discontinued Operations*" section of this MD&A.
(2) Comparative periods have been revised to reflect current period presentation.

	Three Months Ended			Year Ended	
	December 31, 2025	December 31, 2024[(1)]	September 30, 2025	**December 31, 2025**	December 31, 2024[(1)]
Consolidated					
Heavy crude oil (bbl/d)	**54,660**	50,997	53,943	**52,658**	51,107
Light and medium crude oil (bbl/d)	**61**	617	18	**263**	651
Total crude oil (bbl/d)	**54,721**	51,614	53,961	**52,921**	51,758
Bitumen (bbl/d)	**62,538**	59,732	61,157	**61,327**	59,516
NGLs (bbl/d)	**30**	33,126	466	**16,128**	31,229
Total liquids (bbl/d)	**117,289**	144,472	115,584	**130,376**	142,503
Conventional natural gas (mcf/d)	**2,558**	256,386	3,701	**130,729**	243,456
Total (boe/d)	**117,715**	187,203	116,201	**152,163**	183,080

(1) Comparative periods have been revised to reflect current period presentation, see the "*Discontinued Operations*" section of this MD&A.

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" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the generality of the foregoing, this MD&A contains forward-looking information pertaining to the following: the Company's business strategy and future plans; the Company's 2025 and 2026 production and capital spending guidance; 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 ongoing Russia/Ukraine conflict, the conflict in the Middle East, and other heightened geopolitical risks, including the imposition of tariffs or other trade barriers, and the ability of the Company to carry on operations as contemplated in light of the foregoing; determinations by the Organization of the Petroleum Exporting Countries and other countries as to production levels; unanticipated operating results or production declines; changes in tax or environmental laws, climate change, royalty rates or other regulatory matters; changes in Strathcona's development plans or by third party operators of Strathcona's properties; failure to achieve anticipated results of its operations; competition from other producers; inability to retain drilling rigs and other services; failure to realize the anticipated benefits of the Company's acquisitions, 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, 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 the Company's 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.

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, 2025 and the consolidated financial statements, can be found on the internet under the Company's SEDAR+ profile at www.sedarplus.ca and on the Company's website at www.strathconaresources.com.

CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2025 AND 2024

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Independent Auditor's Report

To the Shareholders and the Board of Directors of
Strathcona Resources Ltd.

Opinion

We have audited the consolidated financial statements of Strathcona Resources Ltd. (the "Company"), which comprise the consolidated statements of financial position as at December 31, 2025 and 2024, and the consolidated statements of income and comprehensive income, changes in equity and cash flows for the years then ended, and notes to the consolidated financial statements, including material accounting policy information (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2025 and 2024, and its financial performance and its cash flows for the years then ended in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IASB").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matter

A key audit matter is a matter that, in our professional judgment, was of most significance in our audit of the consolidated financial statements for the year ended December 31, 2025. This matter was addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on this matter.

Property Plant and Equipment – Oil and natural gas properties — Refer to Notes 3 and 7 to the financial statements

Key Audit Matter Description

The Company's property, plant and equipment includes oil and natural gas properties. Oil and natural gas properties, including related facilities are depleted using the unit-of-production method ("depletion") and are evaluated for impairment using the future net cash flows of the underlying proved and probable oil and natural gas reserves.

The Company engages independent reserve engineers to estimate oil and natural gas reserves using estimates, assumptions and engineering data. The Company assesses at each reporting date whether there is an indicator of impairment. If an indicator exists, the Company estimates the recoverable amount of the cash generating unit ("CGU"), which is the higher of fair value less costs to sell or value-in-use. The determination of the Company's proved plus probable oil and natural gas reserves and the related future net cash flows used to measure depletion and determine recoverable amount of a CGU requires management to make significant estimates and assumptions related to future oil and natural gas prices, discount rates, reserves and future operating and development costs. The Company identified indicators of impairment related to the Lloydminster Conventional CGU and recorded an impairment loss.

Given the significant judgments made by management related to future oil and natural gas prices, discount rates, reserves and future operating and development costs used to determine depletion of the Company's oil and natural gas properties and the recoverable amount of the Lloydminster Conventional CGU, these estimates and assumptions are subject to a high degree of estimation uncertainty. Auditing these estimates and assumptions required auditor judgment in applying audit procedures and in evaluating the results of those procedures.

How the Key Audit Matter Was Addressed in the Audit

Our audit procedures related to future oil and natural gas prices, discount rates, reserves and future operating and development costs used to measure depletion and determine the recoverable amount of the Lloydminster Conventional CGU included the following, among others:

- Evaluated future oil and natural gas prices by independently developing a reasonable range of forecasts based on reputable third-party forecasts and market data and comparing those to the oil and natural gas prices selected by management;
- Evaluated the reasonableness of the discount rates by developing a range of independent estimates and comparing those to the discount rates selected by management;
- Evaluated the Company's independent reserve engineers by examining reports and assessing their scope of work and findings and assessing the competence, capability and objectivity by evaluating their relevant professional qualifications and experience;
- Evaluated the reasonableness of reserves by testing the source financial information underlying the reserves and comparing the reserve volumes to historical production volumes;
- Evaluated the reasonableness of future operating and development costs by testing the source financial information underlying the estimate, comparing future development costs to historical results, and evaluating whether they are consistent with evidence obtained in other areas of the audit.

Other Information

Management is responsible for the other information. The other information comprises:

- Management's Discussion and Analysis
- The information, other than the financial statements and our auditor's report thereon, in the Annual Report.

Our opinion on the financial statements does not cover the other information and we do not express any form of assurance conclusion thereon. In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements, or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

We obtained Management's Discussion and Analysis and the Annual Report prior to the date of this auditor's report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor's report. We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by the IASB, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.
As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within the Company as a basis for forming an opinion on the financial statements. We are responsible for the direction, supervision and review of the audit work performed for purposes of the group audit. We remain solely responsible for our audit opinion.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor’s report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor’s report is Mandeep Singh.

/s/ Deloitte LLP

Chartered Professional Accountants
March 11, 2026
Calgary, Alberta

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION
Cdn$ millions

As at	Note	December 31, 2025	December 31, 2024
Assets			
Current			
Accounts receivable	18	**172**	348
Inventory		**43**	48
Prepaid expenses and deposits		**37**	30
Cross-currency swap asset	9, 18	**—**	29
Other assets		**—**	5
Risk management asset	18	**24**	47
Total current assets		**276**	507
Property, plant and equipment	4, 5, 7	**8,493**	10,456
Other assets		**20**	15
Total assets		**8,789**	10,978
Liabilities			
Current			
Accounts payable and accrued liabilities	8	**619**	919
Deferred revenue		**29**	57
Cross-currency swap liability	9, 18	**5**	—
Lease and other obligations	5, 10	**29**	65
Decommissioning provision	5, 11	**42**	41
Risk management liability	18	**21**	45
Total current liabilities		**745**	1,127
Debt	9	**2,095**	2,462
Lease and other obligations	5, 10	**45**	282
Decommissioning provision	5, 11	**196**	250
Deferred tax liability	17	**1,303**	991
Risk management liability	18	**29**	43
Contingent consideration	4	**33**	—
Total liabilities		**4,446**	5,155
Equity			
Share capital	16	**2,270**	3,590
Contributed surplus		**50**	50
Retained earnings		**2,023**	2,183
Total equity		**4,343**	5,823
Total liabilities and equity		**8,789**	10,978

Subscription receipts (Note 15)
Commitments and contingencies (Note 19)
Subsequent events (Notes 16 and 23)
See accompanying notes to the consolidated financial statements.

/s/ Cody Church
Cody Church, Director

/s/ Navjeet (Bob) Singh Dhillon
Navjeet (Bob) Singh Dhillon, Director

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
Cdn$ millions, except per share amounts

For the Year Ended December 31,	Note	2025	2024[1]
Revenues and other income			
Oil and natural gas sales	12	**4,096**	4,373
Sale of purchased products		**67**	75
Royalties		**(435)**	(567)
Oil and natural gas revenues		**3,728**	3,881
Loss on risk management contracts	18	**(86)**	(44)
Midstream revenue		**24**	—
Other income	6	**16**	—
		3,682	3,837
Expenses			
Purchased product		**68**	75
Blending costs		**1,034**	1,081
Production and operating		**672**	641
Transportation		**368**	364
General and administrative		**88**	76
Interest	9	**131**	170
Transaction related costs		**44**	1
Finance costs	13	**56**	50
Depletion, depreciation and amortization	7	**607**	595
Impairment	7	**376**	—
Foreign exchange (gain) loss	14	**(34)**	68
Change in decommissioning liabilities	11	**(13)**	—
		3,397	3,121
Gain on marketable securities	6	**171**	—
Income before income taxes		**456**	716
Income tax expense	17	**90**	209
Income and comprehensive income from continuing operations		**366**	507
Income and comprehensive income from discontinued operations, net of tax	5	**545**	97
Income and comprehensive income		**911**	604
Net income per share	16		
Continuing operations, basic and diluted		**1.71**	2.37
Discontinued operations, basic and diluted	5	**2.54**	0.45
Net income per share, basic and diluted		**4.25**	2.82

(1) Comparative periods have been revised to reflect current period presentation, see Note 5 - Discontinued Operations for additional information.

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
Cdn$ millions

	Note	Share Capital	Contributed Surplus	Retained Earnings	Total Equity
Balance as at December 31, 2023		3,590	50	1,686	5,326
Dividends	**16**	—	—	(107)	(107)
Income and comprehensive income		—	—	604	604
Balance as at December 31, 2024		**3,590**	**50**	**2,183**	**5,823**
Dividends	**16**	—	—	(1,071)	**(1,071)**
Return of capital	**16**	(1,320)	—	—	**(1,320)**
Income and comprehensive income		—	—	911	**911**
Balance as at December 31, 2025		**2,270**	**50**	**2,023**	**4,343**

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
Cdn$ millions

For the Year Ended December 31,	Note	2025	2024
Cash flow from (used in) operating activities			
Net income		**911**	604
Items not involving cash	**21**	**729**	1,332
Adjustments:			
Realized gain on marketable securities	**6**	**(171)**	—
Realized loss on settlement of debt		**54**	—
Decommissioning costs	**11**	**(44)**	(36)
Changes in non-cash working capital	**21**	**(41)**	92
		1,438	1,992
Cash flow (used in) from financing activities			
Draw (repayment) of Credit Facilities	**9, 14**	**383**	(339)
Repayment of senior notes	**9, 14**	**(685)**	—
Lease and other obligations	**10**	**(169)**	(236)
Debt issuance costs		**(20)**	(11)
Cash dividends paid	**16**	**(1,071)**	(107)
Return of capital	**16**	**(1,320)**	—
		(2,882)	(693)
Cash flow from (used in) investing activities			
Property, plant and equipment expenditures	**7**	**(1,186)**	(1,296)
Proceeds from asset dispositions	**5**	**2,399**	—
Property acquisitions	**4, 7**	**(121)**	(41)
Purchase of marketable securities	**6, 18**	**(928)**	—
Proceeds from disposition of marketable securities	**6**	**1,390**	—
Changes in non-cash working capital	**21**	**(110)**	38
		1,444	(1,299)
Change in cash		**—**	—
Cash, beginning of period		**—**	—
Cash, end of period		**—**	—
Cash interest paid		**152**	176

See accompanying notes to the consolidated financial statements.

1. DESCRIPTION OF BUSINESS

Strathcona Resources Ltd. ("**Strathcona**" or the "**Company**") is a corporation that exists under, and is governed by, the provisions of the Business Corporations Act (Alberta) (the "**ABCA**"). Strathcona's Common Shares are listed on the TSX under the trading symbol "SCR".

At December 31, 2025, approximately 69.9% of the Company's shares were owned by certain entities comprising Waterous Energy Fund and its affiliates (collectively, "**WEF**").

Strathcona is focused on the exploration, acquisition, development and production of heavy oil reserves in Western Canada. The consolidated financial statements (the "**financial statements**") include the results of Strathcona Resources Ltd. and its wholly owned subsidiaries.

The Company's head office is located at Suite 1900, 421 – 7 Avenue SW, Calgary, Alberta, Canada, T2P 4K9.

2. BASIS OF PREPARATION

Preparation

These financial statements have been prepared in accordance with IFRS® Accounting Standards (the "**Accounting Standards**") as issued by the International Accounting Standards Board ("**IASB**"). These financial statements were authorized for issue by the Board of Directors on March 11, 2026.

These financial statements have been prepared on the historical cost basis except for those items that are presented at fair value as detailed in the accounting policies disclosed in Note 3.

In these financial statements, all amounts are expressed in Canadian dollars ("**CAD**" or "**C$**") unless otherwise indicated, which is the Company's functional and presentation currency.

Use of estimates and judgments

The preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from those estimated.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Information about certain areas of estimation uncertainty and critical judgments in applying accounting policies that affect amounts recognized in these financial statements is as follows:

Acquisitions

Management is required to exercise judgment in determining whether assets acquired and liabilities assumed constitute a business. A business consists of an integrated set of assets and activities, comprised of inputs and processes, that is capable of being conducted and managed as a business by a market participant.

Significant judgment was applied in determining that the acquisition of the Vawn thermal project ("**Vawn Acquisition**") did not meet the definition of a business under IFRS 3 – *Business Combinations*. The Company elected to apply the standard's optional concentration test and concluded that substantially all of the fair value of the assets acquired was concentrated in a single identifiable asset. As a result, the transaction was accounted for as an asset acquisition.

This assessment had a material impact on the accounting treatment of the transaction, including the recognition of assets and liabilities, the absence of a bargain purchase gain, and the capitalization of transaction costs.

*Identification of operating segments and cash-generating units ("**CGUs**")*

For the purpose of impairment testing, assets that cannot be tested individually are grouped into CGUs, which represent the smallest identifiable group of assets that generates cash inflows largely independent of those from other assets or groups of assets. Significant judgment is applied in determining the composition of CGUs. This includes evaluating the level of integration between assets, the use of shared infrastructure, common sales points, geographic proximity, geological characteristics, and the manner in which operations are monitored and managed internally.

The determination of CGUs can have a material impact on the assessment of asset impairment or reversal, as it affects the allocation of carrying values and the estimation of recoverable amounts. CGUs are reviewed at each reporting date to assess whether changes in operational structure, asset performance, or market conditions warrant a reassessment of CGU composition.

During the year ended December 31, 2025, management reassessed the Company's operating segment structure in light of changes to its asset base, including the divestiture of the Montney segment and the Vawn Acquisition. As a result of this review, the Lloydminster segment was disaggregated into two segments: Lloydminster Thermal and Lloydminster Conventional, to reflect the Company's updated internal reporting and management structure. This change reflects differences in how the chief operating decision makers ("**CODMs**") evaluate performance and allocate resources. Concurrent with the segmentation of the Lloydminster operating segment, the Company bifurcated the Lloydminster CGU.

Oil and natural gas reserves

Proved and probable reserves have been estimated by external experts and are based on a number of underlying assumptions including oil and natural gas prices, future costs, oil and natural gas in place and reservoir performance, all of which are inherently uncertain. Established industry techniques are used to generate these estimates, however, the reserves that are ultimately recovered cannot be known with certainty until the end of the field's life. Changes in reserves estimates could have a material impact on unit-of-production rates used for depletion, timing of decommissioning obligations and impairment of oil and natural gas properties. The Company's reserves are evaluated annually and reported to the Company by its independent qualified reserves evaluator.

Recoverability of property, plant and equipment

At each reporting date, the Company assesses its property, plant and equipment for any indication of impairment. If indicators exist, the associated assets or CGUs are tested by comparing the carrying amount to its recoverable amount, defined as the higher of value in use and fair value less costs of disposal. In practice, the recoverable amount for oil and gas assets is determined using discounted after-tax cash flow forecasts based on proved plus probable reserves for each CGU, as estimated by independent qualified reserves evaluators. These cash flow estimates consider forecast commodity prices, production volumes, reserve lives, operating costs, and development capital requirements, among other factors.

The determination of recoverable amount is highly sensitive to management's assumptions. Significant estimates include future oil and natural gas prices, expected production profiles and reserves, operating and development costs, and the discount rate. These assumptions are based on industry indicators and best estimates at the time of preparation, but they are subject to change as new information emerges. Broader economic and policy developments can impact these assumptions. Market factors such as supply-demand dynamics for oil and gas, geopolitical events, foreign exchange rates, and evolving regulatory standards are all reflected in price and cost assumptions. The estimates and judgments involved in assessing recoverable amounts are inherently uncertain. If actual outcomes differ from our assumptions, particularly if commodity prices or other key inputs change significantly, the Company's asset carrying values, impairment charges, and reversals could change materially in future periods.

*Exploration and evaluation ("**E&E**") assets*

The accounting for E&E assets requires management to make judgments as to whether E&E activities have discovered a sufficient amount of economically recoverable reserves, which requires the quantity and realizable value of such reserves to be estimated. These estimates could be impacted by a shift in demand as global energy markets transition to a lower carbon-based economy. Previous estimates are sometimes revised as new information becomes available.

E&E assets remain capitalized as long as sufficient progress is being made in assessing whether the recovery of the reserves is technically feasible and commercially viable. The concept of "sufficient progress" is a judgmental area, and it is possible to have E&E assets remain classified as such for several years while additional E&E activities are carried out or the Company seeks government, regulatory or internal approval for development plans. E&E assets are subject to ongoing management review to confirm the continued intent to establish the technical feasibility and commercial viability of the discovery. When management is making this assessment, changes to project economics, expected capital investments and production costs, results of other operators in the region, and access to infrastructure and potential infrastructure expansions are important factors considered.

Decommissioning provision

The decommissioning provision is based on estimated inflation and discount rates, current legal requirements, technology, cost of services and expected plans for remediation expenditures. These obligations extend decades into the future, so the ultimate cost and timing are uncertain. Future changes in environmental regulations, the development of new remediation technologies, changes in commodity price inflation, or shifts in field operating plans could materially affect the estimated liability. The Company monitors such factors and updates the decommissioning provision as required.

Financial Instruments

The estimated fair value of financial instruments is reliant upon a number of estimated variables including forward curves for commodity prices and foreign exchange rates. A change in these factors could result in a change to the overall estimated valuation of the instrument.

Income taxes

The calculation of deferred income tax assets and liabilities is based on management's interpretation of applicable laws, regulations, relevant court decisions and estimates regarding the timing of reversals of temporary differences.

3. MATERIAL ACCOUNTING POLICY INFORMATION

Basis of consolidation

The financial statements include accounts of the Company and its subsidiaries. Subsidiaries are entities controlled by the Company. Subsidiaries are consolidated from the date that control commences until the date that control ceases. The accounting policies of subsidiaries align with the policies adopted by the Company. Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the financial statements.

Foreign currency

Transactions in foreign currencies are translated to Canadian dollars at exchange rates on the respective dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Non-monetary assets that are measured in a foreign currency at historical cost are translated using the exchange rate at the date of the transaction. Foreign currency differences arising on translation are recognized in earnings and are reported on a net basis.

Inventory

Inventory consists of raw crude oil, diluent and blended crude oil at the Company's facilities, and in-transit via pipeline and rail. Inventory is carried at the lower of cost and net realizable value. Cost is determined by the first-in first-out method and includes direct purchase costs and costs of production (royalties, production and operating costs, transportation costs, blending costs and depletion of oil and natural gas properties). Net realizable value is the estimated selling price in the ordinary course of business, less applicable selling expenses.

Property, plant and equipment

(i) General

Oil and natural gas properties and corporate assets, collectively "property, plant and equipment", are measured at cost less accumulated depletion, depreciation and amortization and accumulated impairment losses.

(ii) Oil and natural gas properties

The initial cost of an asset comprises its purchase price or construction cost, any transaction costs and other costs directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management, and the initial estimate of a decommissioning obligation.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts are recognized as oil and natural gas properties only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in earnings as incurred. Such capitalized expenditures generally represent costs incurred in developing proved and/or probable reserves and bringing on or enhancing production from such reserves. The carrying amount of any significant replaced or sold component is derecognized. The costs of the day-to-day servicing of oil and natural gas properties are recognized in earnings as incurred.

When significant parts of an item of oil and natural gas properties have different useful lives, they are accounted for as separate items.

Gains and losses on disposal of an item of oil and natural gas properties are determined by comparing the proceeds from disposal with the carrying amount of oil and natural gas properties, and are recognized in earnings.

(iii) Corporate assets

Costs associated with intangible assets, office furniture, fixtures, leasehold improvements, information technology and other corporate assets are carried at cost and depreciated based on the estimated useful lives of the assets.

Corporate assets also includes the recognition of ROU assets, in accordance with IFRS 16. ROU assets are depreciated on a straight-line basis over the shorter of the asset's useful life and the lease term. Depreciation on ROU assets is recognized in depletion, depreciation and amortization.

(iv) Non-monetary exchanges

Non-monetary exchanges of oil and natural gas properties are measured at fair value, unless the transaction lacks commercial substance or the fair value of the asset received or given up cannot be reliably measured. When fair value is not used, the carrying amount of the asset given up is used as the cost of the asset acquired.

(v) Depletion and depreciation

Oil and natural gas properties, including related facilities, are depleted using the unit-of-production method by reference to the ratio of production in the period to the related proved and probable reserves, taking into account estimated, risk adjusted future development costs necessary to bring those reserves into production. These estimates are prepared by independent reserve evaluators at least annually. Oil and natural gas properties are grouped with assets that are dedicated to serving the same reserves.

The estimated useful lives of depreciable assets are as follows:

Furniture and office equipment	30% declining balance
Computer hardware and systems software	30% declining balance
Vehicles	30% declining balance
Facilities	Straight-line over 15 - 20 years
Computer application software	Straight-line over 1 year
Leasehold improvements	Straight-line over the term of the lease

Exploration for and evaluation of mineral resources

E&E costs incurred prior to obtaining the legal right to explore are expensed. Costs incurred after the legal right to explore an area has been obtained are capitalized as exploration and evaluation assets. These costs can include license acquisition, geological and geophysical, drilling, sampling and other directly attributable internal costs. E&E assets are not depreciated and are accumulated in cost centers until technical feasibility and commercial viability of the project, area or field is determined or the assets are determined to be impaired. Technical feasibility and commercial viability of E&E assets is dependent upon the assignment of a sufficient amount of economically recoverable crude oil, condensate, natural gas, and natural gas liquids reserves and available infrastructure to support commercial development, as well as obtaining the appropriate internal and external approvals.

Once technical feasibility and commercial viability has been established for a project, area or field, the E&E assets attributable to those reserves are first assessed for impairment by comparing the carrying amount to the greater of the assets' fair value less costs of disposal or value in use, and are then transferred from E&E assets to oil and natural gas properties. If a decision is made by the Company not to continue an E&E project, the E&E is derecognized and all associated costs are charged to the statement of comprehensive income in E&E expense at that time.

Impairment of non-financial assets

CGUs are reviewed at each reporting date to determine whether there is any indication that the carrying amount may exceed its recoverable amount. If any such indication exists, an impairment test is performed by comparing the CGU's carrying value to its estimated recoverable amount. The recoverable amount of a CGU is the greater of its value in use and its fair value less costs of disposal. An impairment loss is recognized if the carrying amount of a CGU exceeds its estimated recoverable amount.

Impairment losses are recognized in earnings. Impairment losses recognized in respect to CGUs are allocated to reduce the carrying amounts of the assets in the CGU.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss may be reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment loss had been recognized.

Business combinations

The acquisition method of accounting is used to account for business combinations. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of the exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date, irrespective of the extent of any minority interest. The excess of the cost of acquisition over the fair value of the Company's share of the net fair value of the identifiable assets, liabilities and contingent liabilities is recorded as goodwill. If the cost of an acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in earnings.

Transaction costs that are incurred in connection with a business combination, other than those associated with the issuance of debt or equity securities, are recognized in earnings.

There is an option to apply a concentration test that permits a simplified assessment of whether an acquired set of activities and assets is in fact a business. The optional concentration test is met if substantially all of the fair value of the assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets. An entity may make such an election separately for each transaction or other event. If the concentration test is met, the set of activities and assets is determined not to be a business and no further assessment is needed. When an acquisition of a group of assets and liabilities does not meet the definition of a business, the total cost of the acquisition, including directly attributable transaction costs, is allocated to the identifiable assets acquired and liabilities assumed based on their relative fair values at the acquisition date. No goodwill or deferred tax is recognized in an asset acquisition.

Assets held for sale

The Company classifies assets as held for sale when the carrying amount will be principally recovered through a sale transaction rather than through continuing development or use. This condition is met when the sale is highly probable and the asset is available for immediate sale in its present condition. For the sale to be highly probable, management must be committed to a plan to sell the asset and an active program to locate a buyer and complete the plan must have been initiated. The asset must be actively marketed for sale at a price that is reasonable in relation to its current fair value and the sale should be expected to be completed within one year from the date of classification. However, certain events or circumstances beyond the Company's control may extend the period to complete the sale beyond one year.

Where the Company determines that a component of the Company is classified as held for sale and (a) represents a separate major line of business or geographical area of operations (b) is part of a single co-ordinated plan to dispose of a separate major line of business or geographical area of operations; or (c) is a subsidiary acquired exclusively with a view to resale. The Company classifies that component as a discontinued operation.

Immediately before the property, plant and equipment is classified as held for sale it is assessed for indicators of impairment or impairment reversal and is measured at the lower of its carrying amount and fair value less costs of disposal, with any impairment loss or reversal of impairment recognized in the condensed consolidated statement of income. Non-current assets held for sale and their associated liabilities are classified and presented as current assets and liabilities within the consolidated statement of financial position. Assets held for sale are not depleted, depreciated or amortized.

Leases

On the date that a leased asset becomes available for use, the Company recognizes an ROU asset and a corresponding lease obligation. Accretion expense associated with the lease obligation is charged to earnings over the lease period with a corresponding increase to the lease obligation. The lease obligation is reduced as payments are made against the principal portion of the lease. The ROU asset is depreciated over the shorter of the asset's useful life and the lease term on a straight-line basis. Depreciation of the ROU asset is recognized in depletion, depreciation and amortization.

A lease obligation is measured at the commencement date of the lease term at the present value of the future lease payments. The ROU asset is measured at cost, which is comprised of the amount of the initial measurement of the lease obligation, less any incentives received net of any onerous contracts, plus any lease payments made at, or before, the commencement date and initial direct costs and asset restoration costs, if any.

The rate implicit in the lease is used to determine the present value of the liability and ROU asset arising from a lease, unless this rate is not readily determinable, in which case the Company's incremental borrowing rate is used. Generally, the Company uses its incremental borrowing rate as the discount rate.

The lease obligation is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, extension or termination option. A corresponding adjustment is made to the carrying amount of the ROU asset, or is recorded in the earnings if the carrying amounts of the ROU asset has been reduced to nil.

Provisions

(i) General

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The discount rate is adjusted for the Company's credit risk. Provisions are not recognized for future operating losses. The unwinding of the discount is recognized as a finance cost.

(ii) Decommissioning provision

The Company's oil and gas activities give rise to future dismantling, decommissioning, and site restoration obligations. A provision is recognized for these costs based on the present value of management's best estimate of the expenditures required to settle the obligation at the end of an asset's useful life. This estimate incorporates assumptions on the scope of work, when decommissioning will occur, future inflation, and a credit-adjusted discount rate. The resulting present value is capitalized as part of the cost of the related oil and natural gas asset and is depreciated over the asset's useful life. Subsequent changes in the estimated obligation can result from updates to the expected cost, scope or timing of decommissioning activities, or changes in the inflation or discount rates. Such revisions are added to, or deducted from the carrying amount of the associated assets prospectively, where those assets are no longer in use or have been fully impaired, changes are recognized immediately in profit or loss. The provision is also increased over time as the discount unwinds, with this accretion recognized in finance costs. Actual restoration expenditures are charged against the provision as incurred.

Financial instruments

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired, or when the Company has transferred substantially all risks and rewards of ownership.

Financial assets and liabilities are offset and the net amount is reported on the consolidated statement of financial position when there is a legally enforceable right to offset the recognized amounts, and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

(i) Accounts Receivable

Accounts receivable, which are non-derivative financial assets that have fixed or determinable payment terms and are not quoted in an active market, are classified as financial assets at amortized cost and are reported at amortized cost. They are included in current assets.

*(ii) Financial Derivative Instrument*s

Risk management contracts and cross-currency swaps are financial derivative instruments and are included in current assets and liabilities, except for those with maturities greater than 12 months after the end of the reporting period, which are classified as non-current assets and liabilities. The Company has not designated any of its financial derivative contracts as hedging instruments. The Company's financial derivative instruments are classified as financial assets or liabilities at fair value through profit or loss and are reported at fair value with changes in fair value recorded in net income or loss.

(iii) Marketable securities

Marketable securities are listed equity shares and are included in current assets. The Company's marketable securities are classified as financial assets at fair value through profit or loss and are reported at fair value based on changes to quoted share prices. Changes in fair value, and any dividends earned, are recorded through income at each reporting period.

(iv) Accounts Payable, Accrued Liabilities and Long-term Debt

These financial instruments are obligations to pay for goods or services that have been acquired in the ordinary course of business from suppliers or repay borrowings from lenders. They are classified as current liabilities if payment is due within one year or less. These financial instruments are classified as financial liabilities at amortized cost and are reported at amortized cost.

(v) Impairment of Financial Assets

The Company recognizes loss allowances for expected credit losses ("**ECLs**") on its financial assets measured at amortized cost. Due to the nature of its financial assets, the Company measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit loss and are discounted at the effective interest rate of the related financial asset.

Fair value measurements

All financial and non-financial assets and liabilities for which fair value is measured or disclosed in these financial statements are further categorized using a three-level hierarchy based upon the inputs used to measure fair value:

- Level 1: Values are based on unadjusted quoted market prices in active markets for identical assets or liabilities.
- Level 2: Values are based on inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices).
- Level 3: Values are based on unobservable inputs.

The fair value hierarchy gives the highest priority to Level 1 inputs and the lowest priority to Level 3 inputs. At each reporting date, the Company determines whether transfers have occurred between levels in the hierarchy by reassessing the level of classification for each asset or liability measured or disclosed at fair value.

Fair values in these financial statements have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

- The value in use or fair value less costs of disposal is calculated to determine the recoverable amount of non-financial assets that are tested for impairment.
- The fair value of risk management contracts, foreign exchange swaps or cross-currency swaps are based on listed market prices, if available. If a listed market price is not available, then fair value is estimated by discounting the difference between the contractual price and the current forward price for the residual maturity of the contract using a risk-free interest rate.
- The fair value of debt is based upon observable market data and/or other sources utilizing assumptions that market participants would use to determine fair value.
- The fair value of the contingent consideration liability is based on unobservable inputs including estimates of future commodity prices and discount rate.

Revenue

Revenues from the sale of crude oil and natural gas are measured based on the consideration specified in contracts with customers. The Company recognizes revenue when it transfers control of the product to the buyer and collection is reasonably assured. This is generally considered to occur when legal title to the product passes to customers, which is when it is physically transferred to the pipeline or other transportation method agreed upon. Purchases and sales of products that are entered into in contemplation of each other with the same counterparty are recorded on a net basis. Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

The Company satisfies its performance obligations in contracts with customers upon the delivery of crude oil and natural gas, which is generally at a point in time. Performance obligations for services are satisfied over time as the service is provided. The Company sells its production of crude oil and natural gas pursuant to variable price contracts which generally have a term of one year or less. The transaction price for variable price contracts is based on the commodity index price, adjusted for quality, location and other factors depending on the contract terms. The amount of revenue recognized is based on the agreed transaction price with any variability in transaction price recognized in the same period.

The Company's revenue transactions do not contain significant financing components and payments are typically collected on the 25th day of the month following the prior month's production, with revenue being recorded once the product is delivered to a contractually agreed upon delivery point. The Company does not disclose or quantify information about remaining performance obligations that have an original expected duration of one year or less and it does not have any long-term contracts with unfulfilled performance obligations.

Midstream Revenue

Midstream revenue arises from the provision of crude oil transportation, terminalling and handling services at the Company's infrastructure assets. These services are governed by contracts that include variable consideration based on throughput volumes and may include fixed components such as take-or-pay fees.

Revenue from midstream services is recognized when the customer's product has been loaded, transported, or otherwise made available in accordance with the contract terms. The customer obtains control at the point the service is completed and can direct the use of, and obtain substantially all of the remaining benefits from the serviced product. Advance payments received from customers for midstream services are recorded as deferred revenue until the related performance obligations are fulfilled.

Deferred revenue

For certain oil sales transported by rail or certain midstream services involving the Hardisty Rail Terminal ("**HRT**"), the Company receives consideration before the performance obligation is satisfied. These advance payments are recorded as deferred revenue until the Company fulfills the performance obligation. Revenue is recognized at the point in time when control of the product is transferred to the customer, or the agreed service has been provided.

Blending and transportation expenses

The costs associated with the transportation of oil and natural gas, including the cost of diluent used in blending, are recognized when the product is sold.

Income tax

Income tax expense includes current and deferred tax. Income tax expense is recognized in earnings except to the extent that it relates to a business combination, items recognized directly in equity or other comprehensive income.

Current tax is the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date and any adjustment in respect of previous years.

Deferred tax is recorded for the effect of any temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit or loss. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized for unused tax losses, tax credits and deductible temporary differences, to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

Net income per share

Basic net income per share is calculated by dividing the net income attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted net income per share is determined by adjusting the net income attributable to common shareholders and the weighted average number of common shares outstanding for the effects of all potential common shares.

Segment reporting

An operating segment is a component of the Company that engages in business activities from which it may earn revenues and incur expenses. Segment results include items directly attributable to a segment as well as those that can be allocated on a reasonable basis. All inter-segment transactions are eliminated on consolidation.

The operating segments of the Company have been derived because: (a) they engage in business activities from which revenues are earned and expenses are incurred; (b) their operating results are regularly reviewed by the CODMs, identified as the Company's Chief Financial Officer, Chief Commercial Officer and Chief Operating Officer to make decisions about resources to be allocated to each segment and assess its performance; and (c) discrete financial information is available. The Company has three business units established to monitor operational performance of groups of assets at a disaggregated level; financial performance and capital allocation decisions are made at the operating segment level.

Changes in accounting policies

Future Accounting Pronouncements

The Company has not early adopted any standard, interpretation or amendment that has been issued but not yet effective.

IFRS 18 Presentation and Disclosure in Financial Statements

In April 2024, the IASB finalised issuance of Presentation and Disclosure in Financial Statements, which will replace IAS 1, "Presentation of Financial Statements". The objective of IFRS 18 is to set out requirements for the presentation and disclosure of information in general purpose financial statements to help ensure they provide relevant information that faithfully represents an entity's assets, liabilities, equity, income and expenses and provide disclosures on management-defined performance measures in the notes to the financial statements. The standard is effective for annual periods beginning on or after January 1, 2027. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

Amendments to IFRS 9 and IFRS 7 – Classification and Measurement of Financial Instruments

In May and December 2024, the IASB issued amendments to IFRS 9 and IFRS 7 that clarify the derecognition of financial liabilities settled via electronic payment systems, provide guidance on assessing contractual cash flows for financial assets with ESG-linked features, and introduce new disclosure requirements. These amendments are effective for annual periods beginning on or after January 1, 2026. The Company is assessing the impact of these amendments and does not expect them to have a material impact on its financial statements.

4. ACQUISITIONS

2025

Acquisition of Vawn Thermal Project

On December 1, 2025, Strathcona completed the acquisition of the Vawn thermal heavy oil project and certain undeveloped thermal lands for initial consideration paid on closing of $71 million, after closing adjustments, and contingent consideration of up to $75 million. Contingent consideration of $1 million is payable for each dollar per barrel the WCS Index averages above C$70.00 per barrel in a given quarter, payable quarterly, over the 14-quarter period following the close of the transaction. On the acquisition date, the contingent consideration was recognized as a liability measured at fair value. Fair value was determined as the present value of expected future payments using forecasted WCS prices, discounted at 10%.

The Company opted to apply the optional IFRS 3 concentration test, which resulted in the Vawn Acquisition being accounted for as an asset acquisition.

The results of the assets acquired pursuant to the Vawn Acquisition are included in the consolidated financial statements from the date of closing on December 1, 2025.

Assets Acquired and Liabilities Assumed

The following table summarizes the total consideration paid and net assets acquired:

Consideration	
Cash	71
Contingent consideration	33
Capitalized transaction costs	2
Total consideration	106
Oil and natural gas properties	113
Exploration and evaluation assets	3
Decommissioning provision	(10)
Net assets acquired	106

Acquisition of Hardisty Rail Terminal

On April 4, 2025, the Company completed the acquisition of the HRT for cash consideration of $48 million. HRT, located in Hardisty, Alberta, is the largest crude-by-rail terminal in Western Canada. The Company applied the optional IFRS 3 concentration test to the acquisition which resulted in the acquisition being accounted for as an asset acquisition.

5. 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 represents 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 following table summarizes the carrying value of the assets held for sale and liabilities associated with assets held for sale as at December 31, 2025:

	Disposal group
Assets held for sale	
Balance as at December 31, 2024	**—**
Reclassified from property, plant and equipment, net	**2,107**
Prepaid expenses	**5**
Disposition of assets held for sale	**(2,112)**
Balance as at December 31, 2025	**—**
Liabilities associated with assets held for sale	
Balance as at December 31, 2024	**—**
Reclassified from lease and other obligations	**138**
Reclassified from decommissioning provision	**26**
Disposition of liabilities associated with assets held for sale	**(164)**
Balance as at December 31, 2025	**—**
Disposal group, December 31, 2025	**—**

Financial performance and cash flow information

The following table summarizes the Company's financial results from discontinued operations:

For the Year Ended December 31,	2025	2024
Revenues and other income		
Oil and natural gas sales	**521**	963
Royalties	**(35)**	(96)
Oil and natural gas revenues	**486**	867
Expenses		
Production and operating	**76**	171
Transportation and processing	**111**	213
General and administrative	**10**	25
Transaction related costs	**27**	—
Finance costs	**13**	38
Depletion, depreciation and amortization	**90**	279
	327	726
Gain on sale of assets, net (Note 7)	**609**	—
Loss on settlement of other obligations	**(1)**	(4)
Net income before tax from discontinued operations	**767**	137
Income tax expense	**222**	40
Net income from discontinued operations	**545**	97
Net Income from discontinued operations per share	**2.54**	0.45

The following table summarizes the cash flows from discontinued operations:

For the Year Ended December 31,	2025	2024
Cash flow from (used in) discontinued operations		
Operating activities	**260**	437
Financing activities	**(134)**	(198)
Investing activities	**(229)**	(470)
Change in cash from (used in) discontinued operations	**(103)**	(231)
Capital expenditures related to discontinued operations	**229**	470

6. MARKETABLE SECURITIES

Marketable securities represent equity interests in publicly-traded companies that the Company has acquired either through open market transactions or as consideration in the Groundbirch Asset Sale (Note 5). During the year ended December 31, 2025, the Company acquired marketable securities at an aggregate cost of $1,219 million. All such marketable securities were disposed of during 2025 for total cash proceeds of $1,390 million, resulting in a gain on marketable securities of $171 million (year ended 2024 – $nil). The Company also recognized dividend income of $16 million related to these investments in 2025 (2024 – $nil). No marketable securities were held as at December 31, 2025 (December 31, 2024 – $nil).

7. PROPERTY, PLANT AND EQUIPMENT

	Oil and natural gas properties	Exploration and evaluation assets	Corporate assets	Right of use assets	Total
Cost					
Balance, January 1, 2024	11,705	117	48	295	12,165
Additions	1,287	—	9	17	1,313
Acquisition and dispositions	41	—	—	—	41
Change in decommissioning provision (Note 11)	(53)	—	—	—	(53)
Balance as at December 31, 2024	12,980	117	57	312	**13,466**
Additions	1,179	—	7	6	**1,192**
Acquisition (Note 4)	151	3	—	—	**154**
Change in decommissioning provision (Note 11)	3	—	—	—	**3**
Reclassified to assets held for sale	(2,731)	—	—	(177)	**(2,908)**
Balance as at December 31, 2025	**11,582**	**120**	**64**	**141**	**11,907**
Accumulated DD&A and Impairment					
Balance, January 1, 2024	(2,046)	—	(35)	(55)	(2,136)
Depletion, depreciation and amortization	(820)	—	(7)	(47)	(874)
Balance as at December 31, 2024	(2,866)	—	(42)	(102)	**(3,010)**
Depletion, depreciation and amortization	(653)	—	(8)	(35)	**(696)**
Impairment	(509)	—	—	—	**(509)**
Reclassified to assets held for sale	747	—	—	54	**801**
Balance as at December 31, 2025	**(3,281)**	**—**	**(50)**	**(83)**	**(3,414)**
Net book value, December 31, 2024	10,114	117	15	210	10,456
Net book value, December 31, 2025	**8,301**	**120**	**14**	**58**	**8,493**

For the year ended December 31, 2025, $49 million of direct and incremental overhead charges were capitalized (for the year ended December 31, 2024 – $52 million).

The calculation of depletion for the year ended December 31, 2025 includes $9.4 billion of estimated, risk adjusted, future development costs required to bring the Company's estimated proved plus probable reserves on production (December 31, 2024 – $11.5 billion). Depletion for the year ended December 31, 2025 includes an adjustment related to oil inventory of $1 million (December 31, 2024 – $1 million).

Assets Held for Sale

During the year ended December 31, 2025, the Company's Montney assets were classified as held for sale (Note 5). Upon classification, assets held for sale were recorded at the lesser of their carrying value and fair value less costs to sell resulting in an impairment of $133 million (Note 5).

Impairment

Oil and Natural Gas Properties

In response to low commodity prices and operating performance at the Company's Lloydminster Conventional CGU throughout 2025, an impairment test was performed. The recoverable amount of the Lloydminster Conventional CGU was determined to be lower than its carrying amount, as such, the Company recorded an impairment loss of $376 million.

The Company determined the recoverable amount of the Lloydminster Conventional CGU on a fair value-less cost-to-sell basis using a discounted after-tax cash flow model. Future cash flows were estimated based on proved plus probable reserves estimated by the Company's independent reserve evaluator. Key input estimates used in the determination of the recoverable amount include forward price estimates of crude oil and natural gas, volume of reserves and associated assumptions, including production costs, required capital expenditures, reserve life and discount rate. Cash flows were discounted using an after-tax discount rate of 12%, reflecting an asset specific weighted average cost of capital.

The following table details the forward pricing used in estimating the recoverable amount of the Lloydminster Conventional CGU at December 31, 2025, with a 2% increase per year after 2029:

	2026	2027	2028	2029
West Texas Intermediate ("**WTI**") $US/bbl	**59.92**	65.10	70.28	71.93
Western Canadian Select at Hardisty ("**WCS**") $C/bbl	**65.13**	70.43	76.90	78.71

The fair value measurement for the Lloydminster Conventional CGU is categorized within Level 3 of the fair value hierarchy, as it was derived from discounted future cash flows using unobservable inputs. The following table presents the impact to the Lloyd Conventional recoverable amount based on reasonable changes in commodity prices and discount rates:

	Change in commodity prices		Change in discount rate	
	5% Increase	5% Decrease	1% Decrease	1% Increase
Impairment - Lloydminster Conventional CGU	165	593	283	461

Exploration and Evaluation Assets

The Vawn Acquisition included undeveloped land in a pre-existing E&E area of the Company. The consolidation of these lands resulted in a reprioritization of existing lands versus acquired lands. While this change in development plan represents an indicator of impairment, the Company's assessment concluded that the recoverable amount of E&E assets continues to exceed its carrying amount.

8. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at	December 31, 2025	December 31, 2024
Accrued liabilities	**396**	634
Trade payables	**213**	256
Other liabilities	**10**	29
Accounts payable and accrued liabilities	**619**	919

9. DEBT

As at	December 31, 2025	December 31, 2024
Revolving Credit Facility - due Mar 28, 2030[(1)]	**1,876**	1,767
Term Credit Facility - due Mar 28, 2030[(1)]	**240**	—
Senior Notes - due Aug 1, 2026	**—**	719
Unamortized debt issuance costs	**(21)**	(24)
Debt	**2,095**	2,462

(1) The Company periodically borrows from its Revolving Credit Facility in US dollars ("**USD**" or "**US$**") and the Term Credit Facility is denominated in USD. The Company enters into cross-currency interest rate swap ("**CCS**") contracts concurrent with the applicable borrowing dates to take advantage of an interest rate arbitrage that results from the relationship between CAD and USD interest rates and forward foreign exchange curves. Foreign currency risk associated with these borrowings is offset at the time of borrowing using CCS contracts (see Note 18). Debt on the balance sheet includes the CAD equivalent of USD borrowings, translated at the period end exchange rate, which does not include the offsetting impact of CCS contracts. At December 31, 2025, the CCS contracts had a liability value of $5 million (December 31, 2024 - $29 million asset) and total debt includes an unrealized gain of $5 million (December 31, 2024 - unrealized loss of $29 million) related to USD borrowings on the Credit Facilities. Unrealized gains or losses on USD borrowings and offsetting unrealized gains or losses on CCS contracts are included in foreign exchange gains or losses on the Consolidated Statements of Income and Comprehensive Income (see Note 14).

Bank Credit Facilities

(a) Covenant-Based Revolving Credit Facility and Term Credit Facility

At December 31, 2025, the Company had a covenant-based revolving credit facility of $3.24 billion (December 31, 2024 - $2.5 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, 2024 - $nil) (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, Canadian Overnight Repo Rate Average ("**CORRA**") or Secured Overnight Financing Rate ("**SOFR**") plus applicable margins. The applicable margin charged by the lenders is dependent on the Company's Senior Debt to Adjusted EBITDA ratio (as defined below) for the most recently completed quarter. The Credit Facilities are guaranteed by the Company's subsidiaries, and are secured by a security interest in substantially all of the existing and future assets of the Company and its subsidiaries, including by way of a floating charge debenture granted by the Company and each of its subsidiaries.

At December 31, 2025, the Company had letters of credit outstanding under the Revolving Credit Facility of $2 million (December 31, 2024 - $2 million).

(b) Availability under bank credit facilities

Availability under the Company's Credit Facilities is calculated as follows:

As at	December 31, 2025	December 31, 2024
Revolving Credit Facility capacity	**3,240**	2,500
Term Credit Facility capacity[(1)]	**240**	—
Credit Facilities debt[(1)]	**(2,116)**	(1,767)
Unrealized (gain) loss on US borrowings	**(5)**	29
Letters of credit outstanding	**(2)**	(2)
Availability	**1,357**	760

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

(c) 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 December 31, 2025, the Company was in compliance with such financial covenants.

Senior Notes

On December 30, 2025, the Company redeemed its US$500 million senior unsecured notes (the "**Senior Notes**") at 100% of par value. The Senior Notes bore interest at 6.875% per annum, payable semi-annually in arrears on February 1 and August 1 of each year, and had a maturity date of August 1, 2026.

Demand Letter of Credit Facility

At December 31, 2025, the Company had a $200 million (December 31, 2024 - $100 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 December 31, 2025, the Company had letters of credit in the amount of $57 million (December 31, 2024 - $70 million) outstanding under the LC Facility.

Interest Expense

For the Year Ended December 31,	2025	2024
Credit Facilities interest	**81**	146
Senior Notes interest	**48**	47
Realized loss (gain) on interest rate swaps	**2**	(23)
Interest expense	**131**	170

10. LEASE AND OTHER OBLIGATIONS

As at	December 31, 2025	December 31, 2024
Lease obligations, beginning of year	**235**	259
Leases acquired through acquisitions	**8**	—
Additions	**8**	17
Accretion (Note 13)	**14**	24
Settlements	**(53)**	(69)
Foreign exchange	**—**	4
Reclassified to liabilities associated with assets held for sale (Note 5)	**(138)**	—
Lease obligations, end of year	**74**	235
Other obligations, beginning of year	**112**	147
Additions	**—**	112
Accretion (Note 13)	**5**	16
Settlements	**(118)**	(167)
Loss on settlement	**1**	4
Other obligations, end of year	**—**	112
Lease and other obligations, end of year	**74**	347
Lease and other obligations current portion	**29**	65
Lease and other obligations long-term portion	**45**	282

At the beginning of 2024, other obligations included an asset-backed financing agreement on certain processing facility interests with a maturity date of January 1, 2031. This asset-backed financing arrangement gave the Company the option to repurchase the processing facilities interest at any time at specified prices. On July 15, 2024, the Company exercised this repurchase option for $158 million.

On August 9, 2024, Strathcona entered into a new asset-backed financing agreement backed by its interest in certain processing facility interests (the "**Financing Agreement**") for $112 million, which consideration was provided by way of the lender's concurrent assumption of premiums on bought calls from the Company. The asset-backed financing agreement had a maturity date of July 31, 2029. This asset-backed financing arrangement gave the Company the option to repurchase the processing facilities interest at any time at specified prices. On June 30, 2025, Strathcona exercised this repurchase option and settled the liability for $67 million.

The processing facility interests backing the Financing Agreement are associated with assets classified as held for sale, as such, amounts related to this agreement have been presented as discontinued operations (Note 5).

11. DECOMMISSIONING PROVISION

As at	December 31, 2025	December 31, 2024
Balance, beginning of year	**291**	351
Additions	**2**	9
Liabilities acquired	**11**	—
Liabilities disposed	**(2)**	—
Settlements	**(44)**	(36)
Changes in estimates[(1)]	**(21)**	(61)
Accretion (Note 13)	**27**	28
Reclassified to liabilities associated with assets held for sale (Note 5)	**(26)**	—
Balance, end of year	**238**	291
Current portion	**42**	41
Long-term portion	**196**	250

(1) Subsequent changes to decommissioning liabilities for fully depleted end of life assets are recognized in the Consolidated Statements of Income and Comprehensive Income in the period in which they arise.

At December 31, 2025 the estimated amount of undiscounted future cash flows required to settle the obligation were $1.84 billion, $970 million uninflated (December 31, 2024 - $1.93 billion and $1,041 million, respectively). The decommissioning provision is discounted using a credit adjusted rate of 10.0% (December 31, 2024 – 10.0%) and assumes an inflation rate of 2.0% (December 31, 2024 – 2.0%). The decommissioning liabilities are estimated to be settled over periods extending to 2084, with the majority of expenditures expected to be incurred between 2026 and 2050. The present value of the decommissioning provision is sensitive to changes in the credit adjusted discount rate. A 1.0% decrease in the discount rate results in a $27 million increase in the decommissioning provision.

12. OIL AND NATURAL GAS SALES

For the Year Ended December 31,	2025	2024
Bitumen blend	**2,405**	2,576
Heavy oil, blended and raw	**1,688**	1,796
Light oil and condensate	**1**	1
Natural gas	**2**	—
Oil and natural gas sales - continuing operations	**4,096**	4,373
Oil and natural gas sales - discontinued operations (Note 5)	**521**	963
Oil and natural gas sales - continuing and discontinued operations	**4,617**	5,336

13. FINANCE COSTS

For the Year Ended December 31,	2025	2024
Accretion of lease obligations (Note 10)	**14**	24
Accretion of other obligations (Note 10)	**5**	15
Accretion of decommissioning provision (Note 11)	**27**	28
Amortization of debt issuance costs	**23**	21
Finance costs - continuing and discontinued operations (Note 5)	**69**	88

14. FOREIGN EXCHANGE (GAIN) LOSS

For the Year Ended December 31,	2025	2024
Realized loss – operating	**2**	—
Realized loss – Senior Notes	**54**	—
Unrealized (gain) loss – Senior Notes	**(88)**	57
Unrealized (gain) loss – Credit Facilities(1)	**(34)**	70
Unrealized loss (gain) – cross-currency swaps(1)	**34**	(68)
Unrealized (gain) loss – other	**(2)**	9
Foreign exchange (gain) loss	**(34)**	68

(1) Strathcona enters into CCS contracts, which offset foreign currency risk on USD denominated debt drawn under the Credit Facilities. At maturity, the realized gains and losses relating to USD borrowings will be offset by the realized gains and losses on CCS contracts. See Note 9.

15. SUBSCRIPTION RECEIPTS

On May 30, 2025, Strathcona formally commenced an offer to acquire all of the issued and outstanding common shares of MEG Energy Corp. ("**MEG**") not already owned by Strathcona (the “**MEG Transaction**“). In connection with the MEG Transaction, on June 27, 2025, the Company, upon approval of the special committee of the Board comprised solely of independent directors, entered into a subscription receipt agreement with affiliates of Waterous Energy Fund III ("**WEF III**"), a related party of the Company, under which 21.4 million subscription receipts of the Company were issued to WEF III at a price of $30.92 per subscription receipt, for aggregate gross proceeds of $662 million (the "**Subscription Receipt Agreement**"). Under the terms of the Subscription Receipt Agreement, the aggregate proceeds from the issuance of the subscription receipts were placed in escrow.

Under the terms of the Subscription Receipt Agreement, the Company was obliged to make a dividend equivalent payment ("**DEP**") to WEF III in the event that dividends are declared on the Company's common shares prior to either their conversion to common shares or termination of the Subscription Receipt Agreement.

On October 10, 2025, Strathcona terminated its take-over bid for MEG as Strathcona determined that the conditions to the offer were no longer capable of being satisfied in light of the revised definitive agreement between Cenovus Energy Inc. and MEG. This resulted in the termination of the subscription receipts, with the proceeds held in escrow returned to WEF III, and the settlement of the $13 million DEP (or $0.60 per subscription receipt), which is included in transaction costs.

16. SHARE CAPITAL

(a) Share Capital

	Shares	$
Balance, December 31, 2024	214	3,590
Issuance - share pass-through	29	976
Cancellation - share pass-through	(29)	(976)
Return of capital	—	(1,320)
Balance as at December 31, 2025	**214**	**2,270**

Share Pass-Through Transactions

On January 31, 2025, certain limited partnerships of WEF completed a share pass-through transaction that resulted in the disposition of 24,010,576 Strathcona common shares (the "**January Pass-through Transaction**"). Following the January Pass-through Transaction, WEF's ownership of Strathcona's outstanding common shares decreased from approximately 90.8% to approximately 79.6%.

On November 7, 2025, one WEF limited partnership was dissolved, resulting in the disposition of 11,299,917 Strathcona common shares. Following this transaction, WEF's ownership of Strathcona's outstanding common shares decreased from approximately 79.6% to approximately 74.3%.

On December 3, 2025, one WEF limited partnership completed a share pass-through transaction that resulted in the disposition of 9,529,013 Strathcona common shares (the "**December Pass-through Transaction**"). Following the December Pass-through Transaction, WEF's ownership of Strathcona's outstanding common shares decreased from approximately 74.3% to approximately 69.9%.

The total issued and outstanding common shares of Strathcona did not change as a result of these share pass-through transactions.

Special Distribution

On December 22, 2025, Strathcona completed a $10.00 per share distribution to shareholders, $2.14 billion in aggregate, with such amount derived from the cash proceeds received from the Kakwa and Grande Prairie Asset Sales (the "**Special Distribution**"). The Special Distribution was completed as part of a statutory plan of arrangement that entitled shareholders to receive the payment as a dividend or, at their election, a return of capital. The plan of arrangement was approved by Strathcona's shareholders and the Court of King's Bench of Alberta at the end of November 2025.

The Special Distribution was implemented on December 22, 2025. Strathcona's articles were amended to create an unlimited number of Class A common shares. Shareholders who elected to receive a return of capital exchanged their common shares for Class A common shares; 131,994,190 common shares were exchanged for 131,994,190 Class A common shares. The common shares acquired by Strathcona continued to be issued and were held temporarily without a dividend entitlement. A $10.00 per share return of capital was paid on the Class A common shares, $1,320 million in aggregate, and a $10.00 per share dividend was paid on the common shares not held by Strathcona, $822 million in aggregate. Immediately following the payment of the Special Distribution, the Class A common shares were exchanged for common shares and the Class A common shares were cancelled. Strathcona's articles were amended to remove the Class A common shares and are identical to the articles prior to the Special Distribution.

(b) Net Income per Share

Net income per share, basic and diluted, amounts are calculated as net income divided by the weighted average number of common shares outstanding. At December 31, 2025 and 2024, the Company had no dilutive instruments outstanding.

For the Year Ended December 31,	2025	2024
Weighted average common shares (millions) – basic and diluted	**214**	214

(c) Dividends

During the year ended December 31, 2025, excluding the Special Distribution, Strathcona declared and paid total dividends of $249 million or $1.16 per common share (December 31, 2024 - $107 million or $0.50 per common share).

On March 11, 2026, the Strathcona Board of Directors declared a quarterly dividend of $0.30 per common share to be paid on March 27, 2026 to all shareholders of record on March 20, 2026.

17. INCOME TAXES

Estimated future income tax deductions

The Company has approximately $2,790 million of estimated future income tax deductions, in various taxpool categories, available at December 31, 2025 (December 31, 2024 - $5,595 million).

Total income tax expense

For the Year Ended December 31,	2025	2024
Current	**—**	—
Deferred		
Origination and reversal of temporary differences	**98**	176
Change in expected statutory tax rates	**—**	(4)
Adjustments for prior years	**7**	16
Change in unrecognized tax losses	**(15)**	21
	90	209
Total income tax expense - continuing operations	**90**	209

Reconciliation of effective tax rate

For the Year Ended December 31,	2025	2024
Net income before income tax	**456**	716
Expected tax rate	**24.2 %**	24.1 %
Expected income tax expense	**110**	173
Change in unrecognized tax losses	**(15)**	21
Non-taxable portion of net capital (gains) losses	**(14)**	—
Dividends received on marketable securities	**(4)**	—
Change in expected statutory tax rates	**—**	(4)
Adjustments for prior years	**7**	16
Other	**6**	3
Total income tax expense - continuing operations	**90**	209

Recognized deferred income tax asset and liabilities

The movement in deferred income tax assets and liabilities is as follows:

	January 1, 2025	Changes in discontinued operations	Recognized in earnings	December 31, 2025
Deferred income tax assets				
Financial derivative contracts	10	—	(4)	**6**
Decommissioning provision	70	(6)	(6)	**58**
Lease and other obligations	57	(34)	(5)	**18**
Non-capital losses	418	(1)	(206)	**211**
Financing costs	4	—	—	**4**
Other	54	—	(19)	**35**
	613	(41)	(240)	**332**
Deferred income tax liabilities				
Deferred partnership income	(11)	—	11	**—**
Property, plant and equipment	(1,593)	(181)	139	**(1,635)**
	(1,604)	(181)	150	**(1,635)**
Deferred tax liability	**(991)**	**(222)**	**(90)**	**(1,303)**

	January 1, 2024	Recognized in earnings[(1)]	December 31, 2024
Deferred income tax assets			
Financial derivative contracts	25	(15)	**10**
Decommissioning provision	85	(15)	**70**
Lease and other obligations	63	(6)	**57**
Non-capital losses	531	(113)	**418**
Financing costs	4	—	**4**
Other	52	2	**54**
	760	(147)	**613**
Deferred income tax liabilities			
Deferred partnership income	(7)	(4)	**(11)**
Property, plant and equipment	(1,495)	(98)	**(1,593)**
	(1,502)	(102)	**(1,604)**
Deferred tax liability	**(742)**	**(249)**	**(991)**

(1) Includes continuing and discontinued operations.

Non-capital losses

Expiry Year	2033	2034	2035	2036	2037	Thereafter	Total
Non-capital loss balances	39	274	37	158	130	259	897

Unrecognized deferred income tax assets

A temporary difference has not been recognized in respect of the following items:

For the Year Ended December 31,	2025	2024
Property, plant and equipment	**120**	156
Capital losses	**—**	68
Scientific research and experimental development income tax credits	**7**	4
	127	228

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

At December 31, 2025, the Company's financial instruments include accounts receivable, risk management contracts, CCS contracts, accounts payable and accrued liabilities, debt and contingent consideration.

The estimated fair values of the financial instruments have been determined based on the Company's assessment of available market information. These estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. The fair values of the financial instruments, other than the Company's risk management contracts, debt and contingent consideration approximate their carrying amounts due to the short-term maturity of these instruments.

The Company's risk management contracts, CCS contracts and marketable securities are classified as Level 1 in the fair value hierarchy. For purposes of estimating the fair value of risk management contracts and CCS contracts, the Company uses quoted market prices in active markets for identical assets or liabilities. The fair value of debt approximates its carrying amount given the indexed rates of interest.

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. There have been no significant changes in the Company's risk management policies during the year ended December 31, 2025.

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 related to financial derivative contracts 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, may request prepayment and, in certain circumstances, the Company may seek enhanced credit protection from a counterparty or purchase accounts receivable insurance. Receivables from oil and natural gas sales are generally collected on or about the 25th day of the month following production. Joint operations receivables are typically collected within one to three months of the invoice being issued.

The Company's maximum exposure to credit risk at December 31, 2025 is in respect of accounts receivable and risk management assets, net of ECL provision. As at December 31, 2025, $5 million of accounts receivable were past due, all of which were considered collectable (December 31, 2024 – $1 million).

The following table provides a summary of the Company's maximum exposure to credit risk:

As at	December 31, 2025	December 31, 2024
Oil and natural gas sales	**158**	325
Joint interest partners	**7**	5
Other	**10**	20
	175	350
Allowance for credit losses	**(3)**	(2)
Accounts receivable	**172**	348
Cross-currency swap asset	**—**	29
Risk management asset	**24**	47
Total credit exposure	**196**	424

The oil and gas industry has a pre-arranged monthly clearing day for payment of revenues from all buyers of oil and natural gas, which occurs on or about the 25th day following the month of sale. As a result, the Company's oil and natural gas sales receivables are current. All other accounts receivable are generally contractually due within 30 days.

The Company had one external customer exceeding 10% of total oil and natural gas sales that accounted for approximately 16% or $743 million of the Company's revenue for the year ended December 31, 2025 (December 31, 2024 – zero external customers). Included in accounts receivable at December 31, 2025 was $158 million of accrued sales revenue for December 2025 production (December 31, 2024 - $325 million for December 2024 production). At December 31, 2025, the Company had one external customer who accounted for 27% or $46 million of the total accounts receivable balance (December 31, 2024 – one external customer for 10% or $31 million).

Credit risk related to joint interest receivables is mitigated by obtaining partner approval of significant capital expenditures prior to expenditure and in certain circumstances may require cash deposits in advance of incurring financial obligations on behalf of joint interest partners. The Company may have the ability to withhold production from joint interest partners in the event of non-payment or may be able to register security on the assets of joint interest partners.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. 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 financial covenants. As of the date of these financial statements, management's forecasts for the Company indicate that financial covenants for the next twelve months will be met under the Credit Facilities and that the Company has sufficient resources to manage a working capital deficit when required.

At December 31, 2025, the Company had availability under the Credit Facilities of $1,357 million after considering letters of credit outstanding. At December 31, 2024, availability under the Revolving Credit Facility was $760 million, see Note 9. Future liquidity depends on the ability of the Company to access debt markets, availability under credit facilities, availability of additional equity, cash flow from operations and the ability to comply with financial covenants. Various industry risk factors, including uncertainty around improvements in global commodity prices and pipeline and transportation capacity constraints in Western Canada, may adversely affect the Company's future liquidity.

At December 31, 2025, the Company had working capital deficit of $396 million (December 31, 2024 - working capital deficit of $545 million).

The following tables detail the cash flows and contractual maturities of the Company's financial liabilities:

As at December 31, 2025	Total	<1 year	1-3 years	4-5 years	> 5 years
Credit Facilities[1] (Note 9)	**2,121**	—	—	2,121	—
Accounts payable and accrued liabilities	**619**	619	—	—	—
Risk management contract liability	**50**	21	29	—	—
Lease obligations[2] (Note 10)	**95**	33	25	10	27
Total	**2,885**	673	54	2,131	27

(1) Contractual amount reflects contracted settlement price on CCS contracts and excludes future interest payments on borrowings.
(2) Amounts relate to undiscounted payments for lease obligations, see Note 10.

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.

As at December 31, 2025, the following table summarizes the fair values of the Company's risk management contracts (excluding cross-currency interest rate swaps):

As at	December 31, 2025			
	Commodity	Foreign Exchange	Interest Rate	Total
Risk management asset – current	**24**	**—**	**—**	**24**
Risk management liability – current	**(5)**	**(15)**	**(1)**	**(21)**
Risk management liability – long-term	**—**	**—**	**(29)**	**(29)**
Total asset (liability)	**19**	**(15)**	**(30)**	**(26)**

As at	December 31, 2024			
	Commodity	Foreign Exchange	Interest Rate	Total
Risk management asset – current	47	—	—	47
Risk management liability – current	—	(43)	(2)	(45)
Risk management liability – long-term	—	(14)	(29)	(43)
Total asset (liability)	47	(57)	(31)	(41)

The Company's (loss) gain on risk management contracts was as follows:

For the Year Ended December 31,	2025	2024
Loss on risk management contracts - realized	**(100)**	(107)
Gain on risk management contracts - unrealized	**14**	63
Total loss on risk management contracts	**(86)**	(44)

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 may be impacted by global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, global pandemic or natural disasters and respective responses from various levels of government, economic and geopolitical factors. Changes in commodity prices could have a significant positive or negative impact on Strathcona's net income.

As at December 31, 2025, the Company had the following crude oil sales contracts in place:

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

As at December 31, 2025, the Company had the following natural gas purchase contracts in place:

Term	Contract	Index	Currency	Volume	Units	Price
Jan 1, 2026 - Dec 31, 2026	Swap	AECO	CAD	100,000	GJ/d	$2.68

The fair value of the Company's risk management contracts as at December 31, 2025 are sensitive to fluctuations in commodity prices. With all other variables held constant, a 10% increase in commodity prices could increase the unrealized loss on risk management contracts by $22 million, impacting income before income taxes. A 10% decrease in commodity prices could reduce the unrealized loss on risk management contracts by $23 million, impacting income before income taxes.

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.

The following table summarizes the Company's foreign exchange contracts on revenues as at December 31, 2025:

Term	Contract	Bought Put - USD per Month	Bought Put Price - CAD/ USD	Sold Call - USD per Month	Sold Call - CAD/ USD
Jan 1, 2026 - Jun 30, 2026	Collar	100 million	1.2500	130 million	1.4500

The following table summarizes the Company's foreign exchange contract on the redeemed Senior Notes as at December 31, 2025:

Expiry	Contract	USD	CAD/USD Strike
Jul 31, 2026	Sold Put Option	500 million	1.3775

Foreign exchange risk on USD denominated borrowings on the Credit Facilities is offset by entering into CCS contracts at the time of a USD borrowing. As part of the CCS, the CAD/USD foreign exchange rate at the beginning and end of the SOFR borrowing term is fixed so the Company does not have any foreign exchange risk on its USD borrowings. As at December 31, 2025, the Company had the following CCS contracts outstanding:

Notional (US$)	Maturity Date	Contract Price
825 million	January 26, 2026	CAD/USD 1.3778
175 million	January 29, 2026	CAD/USD 1.3775

The carrying amounts of the Company's USD denominated monetary assets and liabilities exposed to fluctuations in the CAD/USD foreign currency exchange rate are as follows:

As at	December 31, 2025	December 31, 2024
(US$)		
Assets	**206**	111
Liabilities	**(89)**	(623)
Net assets (liabilities)	**117**	(512)

With all other variables held constant, a $0.01 change in the CAD/USD foreign exchange rate at December 31, 2025 would result in a change in USD denominated monetary assets and liabilities and change in Income and Comprehensive Income before income taxes by $1 million (December 31, 2024 – $5 million).

Interest rate risk

The Company is exposed to movements in floating interest rates on the Credit Facilities. At December 31, 2025, the following interest rate risk management contracts were in place:

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(1)	CORRA	3.09%

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

At December 31, 2025, a 50 basis point increase in interest rates would result in an increase in annualized interest expense and decrease in income before income taxes of $11 million, while a decrease of 50 basis points would result in a decrease in annualized interest expense and increase in income before taxes of $4 million.

Capital management

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.

19. COMMITMENTS AND CONTINGENCIES

As at December 31, 2025, the Company is committed to the following non-cancellable payments:

	Total	< 1 year	1-3 years	4-5 years	> 5 years
Transportation and processing	**2,646**	169	284	382	1,811
Capital	**175**	162	13	—	—
Other	**62**	48	13	1	—
Total	**2,883**	379	310	383	1,811

20. RELATED PARTY TRANSACTIONS

For the year ended December 31, 2025 related party transactions included the WEF III subscription receipts (Note 15), the WEF share pass-through transactions (Note 16) and key management compensation.

Key management personnel of the Company include its officers and directors. Amounts recorded by the Company relating to compensation of directors and officers were as follows:

For the Year Ended December 31,	2025	2024
Key management compensation	**12**	22

21. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

For the Year Ended December 31,	2025	2024
Source (use) of cash:		
Accounts receivable	**179**	(14)
Inventory	**4**	(3)
Prepaid expenses and deposits	**(12)**	(2)
Other assets - Sable remediation fund	**5**	—
Accounts payable and accrued liabilities	**(299)**	129
Deferred revenue	**(28)**	20
	(151)	130
Related to operating activities	**(41)**	92
Related to investing activities	**(110)**	38

Items not involving cash

For the Year Ended December 31,	2025	2024
Depletion, depreciation and amortization	**697**	874
Impairment (Note 7)	**376**	—
Change in decommissioning liabilities	**(13)**	—
Unrealized gain on risk management contracts (Note 18)	**(14)**	(63)
Unrealized (gain) loss on foreign exchange (Note 14)	**(90)**	68
Finance costs (Note 13)	**69**	88
Loss on settlement of other obligations (Note 10)	**1**	4
Gain on sale of assets, net (Note 5)	**(609)**	—
Realized loss on deferred premium settlement	**—**	112
Deferred tax expense	**312**	249
	729	1,332

22. SEGMENT INFORMATION

Segment disclosures reflect the manner in which the Company's CODMs evaluate and allocate resources among the Company's principal operations.

During the year ended December 31, 2025, management reassessed the Company's operating segment structure in light of changes to its asset base, including the divestiture of the Montney segment and the Vawn Acquisition. As a result of this review, the Lloydminster segment was disaggregated into two segments: Lloydminster Thermal and Lloydminster Conventional, to reflect the Company's updated internal reporting and management structure. This change reflects differences in how the CODMs evaluate performance and allocate resources.

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, which includes HRT (Note 4).

The following tables present the financial performance by reportable segment and include a measure of segment profit or loss regularly reviewed by the CODMs for the noted periods ended December 31, 2025 and 2024. Certain comparative information related to finance costs and general and administrative costs have been allocated by segment to conform with current period presentation. For the year ended December 31, 2024, Field Operating Earnings was used by the CODMs to evaluate segment profit or loss. Operating Earnings was used by the CODMs commencing for the period ended March 31, 2025.

For the Year Ended December 31,	Cold Lake 2025	Cold Lake 2024	Lloydminster Thermal[1] 2025	Lloydminster Thermal[1] 2024	Lloydminster Conventional[1] 2025	Lloydminster Conventional[1] 2024	Corporate and Midstream 2025	Corporate and Midstream 2024	Consolidated[2] 2025	Consolidated[2] 2024
Segment revenues										
Oil and natural gas sales	**2,405**	2,576	**982**	954	**708**	843	**1**	—	**4,096**	4,373
Sale of purchased product	**10**	18	**—**	—	**23**	26	**34**	31	**67**	75
Midstream sales	**—**	—	**—**	—	**—**	—	**24**	—	**24**	—
Royalties	**(287)**	(385)	**(69)**	(86)	**(79)**	(96)	**—**	—	**(435)**	(567)
Oil, natural gas, and midstream sales	**2,128**	2,209	**913**	868	**652**	773	**59**	31	**3,752**	3,881
Segment expenses										
Purchased product	**10**	18	**—**	—	**23**	26	**35**	31	**68**	75
Blending costs	**883**	930	**28**	14	**123**	137	**—**	—	**1,034**	1,081
Production and operating	**317**	324	**184**	165	**156**	152	**15**	—	**672**	641
Transportation	**86**	88	**253**	224	**29**	52	**—**	—	**368**	364
Depletion, depreciation and amortization	**168**	167	**251**	226	**175**	185	**13**	17	**607**	595
General and administrative	**33**	28	**29**	25	**26**	23	**—**	—	**88**	76
Finance costs	**3**	4	**3**	4	**1**	—	**49**	42	**56**	50
Other income	**—**	—	**—**	—	**—**	—	**(16)**	—	**(16)**	—
Interest	**—**	—	**—**	—	**—**	—	**131**	170	**131**	170
	1,500	1,559	**748**	658	**533**	575	**227**	260	**3,008**	3,052
Operating earnings	**628**	650	**165**	210	**119**	198	**(168)**	(229)	**744**	829
Impairment					**376**	—			**376**	—
Loss on risk management contracts							**86**	44	**86**	44
Transaction related costs							**44**	1	**44**	1
Foreign exchange (gain) loss							**(34)**	68	**(34)**	68
Gain on marketable securities							**(171)**	—	**(171)**	—
Change in decommissioning liabilities							**(13)**	—	**(13)**	—
Income before income taxes									**456**	716
Deferred tax expense									**90**	209
Income and comprehensive income from continuing operations									**366**	507
Income and comprehensive income from discontinued operations, net of tax									**545**	97
Income and comprehensive income									**911**	604

(1) Comparative periods have been revised to reflect current period presentation.
(2) Comparative period has been revised to reflect current period presentation, see Note 5 - Discontinued Operations for additional information.

For the Year Ended December 31,	Cold Lake		Lloydminster Thermal(1)		Lloydminster Conventional(1)		Corporate and Midstream		Consolidated(2)	
	2025	2024	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024
Capital expenditures - continuing operations	**371**	372	**415**	260	**164**	185	**7**	9	**957**	826
Decommissioning costs - continuing operations	**—**	—	**—**	—	**—**	—	**42**	15	**42**	15

(1) Comparative periods have been revised to reflect current period presentation.
(2) Comparative period has been revised to reflect current period presentation, see Note 5 - Discontinued Operations for additional information.

23. SUBSEQUENT EVENTS

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 Board of Directors has approved Strathcona's filing of an application with the Toronto Stock Exchange ("**TSX**") for a normal course issuer bid ("**NCIB**"). Once approved by the TSX, Strathcona may buyback up to 5% of its issued and outstanding shares (up to a maximum of approximately 10.7 million common shares of the Company) over a twelve month period.

On March 11, 2026, Strathcona acquired a 50% operated working interest in the Selina property, located in the Cold Lake Thermal segment, along with additional surrounding lands, for total consideration of $23 million. Following the acquisition, Strathcona holds a 100% operated working interest in Selina.

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