Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") of Cavvy Energy Ltd. ("Cavvy", "we", "our" or the "Company") provides a review by management of the financial performance and position of the Company, as well as the trends and external factors which may impact the Company's prospects. This MD&A has been prepared as of March 18, 2026, and should be read in conjunction with the Company's audited consolidated financial statements and the accompanying notes for the year ended December 31, 2025 and 2024 (the "Consolidated Financial Statements") as well as Cavvy's December 31, 2025 Annual Information Form ("AIF"). The Consolidated Financial Statements are prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board ("IASB"). Our reporting currency is the Canadian dollar ("CAD"). All amounts are presented in CAD, unless otherwise stated.

When preparing the MD&A, the Company considers the materiality of information. Information is considered material if (i) such information results in, or would reasonably be expected to result in, a significant change in the market price or value of the Company's shares; (ii) there is a substantial likelihood that a reasonable investor would consider it important in making an investment decision; or (iii) it would significantly alter the total mix of information available to investors. The Company evaluates materiality with reference to all relevant circumstances, including potential market sensitivity.

Condensate is a natural gas liquid as defined by National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. Throughout this MD&A, natural gas liquids ("NGLs") comprise all NGLs as defined by NI 51-101 other than condensate, which is disclosed separately. Reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("boe"). A boe is derived by converting six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of crude oil (6 mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 mcf:1 bbl conversion ratio may be misleading as an indication of value.

This MD&A includes references to certain financial measures that are not defined under IFRS and are considered non-GAAP financial measures. Management believes these financial measures are important to the understanding of the Company's business activities. The measures Cavvy uses may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, measures determined in accordance with IFRS. Management uses these non-GAAP financial measures to evaluate the Company's operating performance, financial position and liquidity. The non-GAAP financial measures are reconciled to their closest GAAP measure. See Non-GAAP and Other Financial Measures section of the MD&A for definitions of these measures.

During the second quarter of 2025 Cavvy underwent a rebranding process. With the approval of shareholders at the May 8th 2025 Annual General Meeting, the name change from Pieridae Energy Limited was made official. Cavvy trades on the TSX under the symbol CVVY. Continuous disclosure materials are available on our website. www.cavvyenergy.com, or on SEDAR, www.sedarplus.com.

CAVVY'S OBJECTIVES AND STRATEGY

Cavvy is a Canadian energy company headquartered in Calgary, Alberta, and a significant upstream producer and midstream gathering and processing ("G&P") operator with core assets concentrated in western Alberta. Cavvy's business is focused on safely producing, processing and delivering treated natural gas, condensate, NGLs and sulphur to market.

Management is optimistic about investment opportunities within the Company's existing asset base and in the regions in which it operates. As Cavvy continues to mature its deep inventory of conventional drilling prospects, it is focused on diversifying revenue and improving cash flow by increasing third-party utilization of owned G&P infrastructure, which consists primarily of three major sour gas processing and fractionation facilities – the "Waterton Facility", the "Jumping Pound Facility" and the "Caroline Facility", and associated gathering systems. These assets are strategically located to provide local customers competitive processing and egress to natural gas, condensate, NGL, and sulphur markets. The long-term, low decline characteristics of the Company's reserve base and supporting infrastructure allow continued creation of long-term shareholder value through strategic execution across the following core pillars:

- Sustaining a safe and regulatory compliant business.
- Expanding utilization of the Company's G&P assets by competitively attracting third-party volumes derived from existing production, local capacity consolidation, and new development drilling within the reach and capacity of its gathering systems.
- Proving the Company's resource upside by successfully investing in identified high impact drilling opportunities.
- Improving capital structure and financial flexibility by reducing leverage.
- Identifying and pursuing cashflow growth and revenue diversification opportunities.
- Instilling and driving a high-performance culture.

- Mitigating or eliminating carbon compliance cost through facility utilization and emissions reduction initiatives.
- Applying technology solutions to improve profitability.
- Seeking new markets for its products; and
- Pursuing emerging opportunities aligned with implementing a "new ventures" strategy.

ANNUAL HIGHLIGHTS

The table below provides a summary of consolidated financial results for the years ended 2025, 2024 and 2023:

($ 000s unless otherwise noted)	2025	2024	2023
Production			
Natural gas (mcf/d)	**114,730**	139,710	168,821
Condensate (bbl/d)	**2,320**	2,397	2,339
NGLs (bbl/d)	**2,462**	2,082	2,296
Total production (boe/d) (1)	**23,904**	27,763	32,772
Sulphur (mt/d)	**1,078**	1,319	1,306
Third party volumes processed (mcf/d) (2)	**122,013**	65,475	60,834
Reserves			
Net proved plus probable ("2P") reserves NPV10 (3)	**1,505,907**	1,252,170	1,371,735
Proved developed producing ("PDP") reserves NPV10 (3)	**711,083**	621,393	614,072
2P reserve life index ("RLI")	**25.83**	25.08	20.38
Financial			
Natural Gas Price ($/mcf)			
Realized before Risk Management Contracts (4)	**1.74**	1.58	2.67
Realized after Risk Management Contracts (4)	**3.65**	3.15	3.67
Benchmark natural gas price	**1.68**	1.45	2.63
Condensate Price ($/bbl)			
Realized before Risk Management Contracts (4)	**85.08**	94.48	97.01
Realized after Risk Management Contracts (4)	**84.59**	86.73	95.55
Benchmark condensate price	**88.54**	100.02	102.73
Sulphur Price ($/mt)			
Realized sulphur price (5)	**31.68**	13.52	21.86
Benchmark sulphur price USD (Vancouver FOB)	**285.35**	94.04	94.18
Revenue (6)	**293,838**	268,840	374,029
Net (loss) income	**(4,871)**	(38,905)	8,981
Net (loss) income $ per share basic	**(0.02)**	(0.20)	0.06
Net (loss) income $ per share diluted	**(0.02)**	(0.20)	0.04
Net operating income (7)	**110,457**	64,608	130,929
Cashflow provided by operating activities	**36,453**	7,132	104,202
Funds flow from operations	**62,625**	19,115	85,692
Operating netback ($/boe) (7)	**12.66**	6.35	10.95
Total assets	**539,136**	612,423	638,541
Adjusted working capital deficit (7)	**(19,769)**	(29,777)	(31,830)
Net debt (7)	**(170,617)**	(197,564)	(204,046)
Non-current liabilities	**290,762**	326,853	300,261
Capital expenditures (8)	**23,359**	25,697	55,539

(1) Total production excludes sulphur.
(2) Third-party volumes processed are raw natural gas volumes reported by activity month.
(3) Estimated pre-tax net present value of discounted cash flows from reserves based on IC4 pricing assumptions using a 10% discount rate.
(4) Includes physical commodity and financial risk management contracts inclusive of cash flow hedges, together ("Risk Management Contracts"). The realized natural gas price after Risk Management Contracts shown above is normalized to exclude the impact of hedge monetization.
(5) Realized sulphur price is net of customary deductions such as transportation, handling, marketing, and storage fees.
(6) Revenue is inclusive of petroleum and natural gas revenue, royalties, processing, marketing and other revenue, and realized gains and losses on risk management contracts.
(7) Refer to the "Net Operating Income", "Operating Netback", "Capital Resources", "Funds Flow from Operations", "Working Capital and Capital Strategy", and "Non-GAAP and Other Financial Measures" sections of this MD&A for the compositions and definitions of non-GAAP and other financial measures.
(8) Excludes reclamation and abandonment activities.

QUARTERLY HIGHLIGHTS

The table below provides a summary of the consolidated financial results for the current quarter and the previous seven quarters:

	2025				2024			
($ 000s unless otherwise noted)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production								
Natural gas (mcf/d)	**111,834**	115,467	126,198	105,338	111,787	115,196	157,077	175,356
Condensate (bbl/d)	**2,065**	2,258	2,507	2,454	2,149	2,191	2,472	2,781
NGLs (bbl/d)	**2,299**	2,454	2,524	2,574	1,788	1,726	2,210	2,613
Total production (boe/d) (1)	**23,003**	23,956	26,064	22,584	22,568	23,116	30,861	34,620
Sulphur (mt/d)	**989**	1,120	1,128	1,076	968	1,444	1,376	1,491
Third-party volumes processed (mcf/d) (2)	**136,579**	138,544	121,319	90,926	74,650	72,654	55,688	58,730
Financial								
Natural gas price ($/mcf)								
Realized before Risk Management Contracts (3)	**2.41**	0.66	1.73	2.24	1.55	0.77	1.14	2.53
Realized after Risk Management Contracts (3)	**3.60**	3.25	3.23	3.58	3.36	3.43	2.71	3.21
Benchmark natural gas price (AECO)	**2.25**	0.62	1.72	2.14	1.46	0.68	1.17	2.48
Condensate price ($/bbl)								
Realized before Risk Management Contracts (3)	**76.62**	82.65	84.60	95.15	94.87	92.13	99.96	91.18
Realized after Risk Management Contracts (3)	**79.75**	83.66	85.88	88.29	90.61	84.61	87.75	84.49
Benchmark condensate price (C5 at Edmonton)	**79.61**	86.58	87.71	100.24	98.85	97.10	105.62	98.43
Sulphur price ($/mt)								
Realized sulphur price (4)	**43.22**	34.59	32.40	17.00	12.09	8.86	18.43	14.49
Benchmark sulphur price USD (Vancouver FOB)	**414.47**	268.42	271.75	184.42	135.78	97.49	73.82	68.57
Net (loss) income	**(1,598)**	(10,086)	4,147	2,666	(20,921)	7,496	(19,196)	(6,284)
Net (loss) income $ per share, basic	**(0.01)**	(0.03)	0.01	0.01	(0.08)	0.04	(0.12)	(0.04)
Net (loss) income $ per share, diluted	**(0.01)**	(0.03)	0.01	0.01	(0.08)	0.04	(0.12)	(0.04)
Net operating income (5)	**20,785**	30,631	26,491	32,550	13,720	19,818	7,652	23,418
Cashflow provided by (used in) operating	**7,776**	4,466	1,599	22,612	(592)	2,260	(1,555)	7,049
Funds flow from operations (5)	**13,518**	12,898	14,502	21,707	3,341	8,234	(4,874)	12,044
Operating netback ($/boe) (5)	**9.82**	13.90	11.17	16.02	6.61	9.31	2.74	7.44
Total assets	**539,136**	536,274	553,216	571,470	612,423	615,040	585,940	590,531
Adjusted working capital deficit (5)	**(19,769)**	(10,631)	(20,144)	(30,540)	(29,777)	(42,658)	(37,986)	(31,671)
Net debt (5)	**(170,617)**	(163,697)	(166,878)	(185,438)	(197,564)	(206,779)	(219,204)	(209,964
Capital expenditures (6)	**10,404**	4,022	2,391	6,542	5,800	10,002	5,003	4,897

(1) Total production excludes sulphur.
(2) Third-party volumes processed are raw inlet natural gas volumes reported by activity month.
(3) Includes physical commodity and financial risk management contracts inclusive of cash flow hedges, (together "Risk Management Contracts"). The realized natural gas price after Risk Management Contracts shown above is normalized to exclude the impact of the hedge monetization.
(4) Realized sulphur price is net of deductions such as transportation, marketing and storage fees.
(5) Refer to the "Net Operating Income", "Operating Netback", "Capital Resources", "Funds Flow from Operations", "Working Capital and Capital Strategy", and "Non-GAAP and Other Financial Measures" sections of this MD&A for the compositions and definitions of non-GAAP and other financial measures.
(6) Excludes reclamation and abandonment activities.

2025 OPERATIONAL AND FINANCIAL HIGHLIGHTS

Annual Highlights

- Generated net operating income ("NOI") of $110.5 million (operating netback of $12.66 per boe), 71% higher than 2024.
- Produced 23,904 boe/d (80% natural gas), 14% lower than 2024 primarily reflecting the ongoing voluntary shut-ins which impacted annual production by 8,700 boe/d in 2025.
- Produced 1,078 mt/d of sulphur, 86% of which was sold under the legacy pricing agreement that expired December 31, 2025 ("Legacy Sulphur Pricing Agreement").
- Processed 122.0 mcf/d of third-party raw natural gas, an increase of 56.5 mcf/d (86%) from 2024. This resulted in an increase in third-party processing and marketing revenues of 92% to $38.8 million.
- Reduced net debt by $26.9 million to $170.6 million through repayment of long-term debt and reduction of non-cash working capital deficit.

- Invested $9.4 million into high impact, quick payout facility and well optimization projects funded by the 2024 rights offering (“Rights Offering Projects”), delivering an aggregate return of 147%.
- Reduced operating costs by 11%, driven by the successful execution of optimization initiatives resulting in reduced labour and maintenance costs, decreases in fuel gas, chemical usage, GHG emission intensity, and power consumption, as well as third-party processing cost savings due to voluntary production shut ins.
- Recorded 2025 2P NPV10 reserves of $1,506 million, an increase of 20% from 2024 reserves.
- Monetized certain in-the-money 2026 and 2027 AECO natural gas contracts, which resulted in net proceeds of $10.2 million. Proceeds from the hedge monetization plus internally generated cashflow were directed to the repayment of $35.0 million of long-term debt (USD $25.4 million) during the year.
- Rebranded to Cavvy Energy Ltd. on May 12, 2025, completing the Company’s multi-year strategic pivot and affirming Cavvy’s identity as a western Canadian upstream and midstream company.

Fourth Quarter Highlights

- Generated NOI of $20.8 million (operating netback of $9.82 per boe), 51% higher than 2024.
- Produced 23,003 boe/d (81% natural gas), up 2% from the fourth quarter of 2024. Produced 989 mt/d of sulphur, 88% of which was sold under the Legacy Sulphur Pricing Agreement.
- Increased third-party raw gas processing volumes by 83% to 136.6 MMcf/d compared to fourth quarter of 2024. This resulted in a 135% increase in third-party processing and marketing revenue or $7.2 million for the quarter compared to the fourth quarter of 2024.
- Restarted 2,770 mcf/d of natural gas production in Northeast BC as AECO pricing rose above break even thresholds.
- Incurred reclamation and abandonment spend of $5.8 million focused on BC liability reduction in winter only access properties.
- Entered into a 2026 structured sulphur pricing agreement with a third-party sulphur marketer (the “Sulphur Pricing Agreement”), as previously disclosed in November 2025, to provide sulphur revenue certainty while retaining ability to participate in the spot sulphur market.

On January 6, 2026, Cavvy received a cash payment of approximately USD $26.7 million representing the prepayment of a portion of sulphur sales expected over the first half of 2026 at a predefined price in accordance with the terms of the Sulphur Pricing Agreement (the “Prepayment”). With proceeds from the Prepayment, Cavvy repaid the full USD $18.1 million outstanding balance of the senior revolving loan (“Revolving Loan”) in January 2026 and a further USD $8.9 million of senior term loan during the first quarter of 2026, resulting in interest expense savings over 2026 and accelerating progress towards the Company’s year-end debt and leverage targets.

Simultaneously, Cavvy recognized deferred revenue of approximately $36.2 million representing the obligation to deliver sulphur volumes, which will be reduced monthly between January and June 2026 as volumes are delivered.

On March 12, 2026, Cavvy announced the exercise of common share purchase warrants for proceeds of $3.5 million in exchange for the issuance of 5,120,235 common shares.

Discretionary Production Shut-ins

Cavvy continually evaluates the economic performance of its producing assets to optimize cash flow during periods of sustained low commodity prices. Management has historically elected to temporarily shut in selected low-margin properties when breakeven commodity prices are not achieved, in order to preserve reserve value. Reactivating shut-in production can typically be mechanically completed within one to two weeks, and subsequent well performance is not expected to be negatively impacted by these shut-ins.

During the second and third quarters of 2024, several dry gas properties in Northern Alberta Foothills, Northeast BC, and Central Alberta (“CAB”) which produce to non-operated processing facilities were shut-in due to low AECO natural gas prices and high variable operating costs. During the first quarter of 2025 AECO pricing improved sufficiently to reactivate approximately 1,000 boe/d of production in Northern Alberta Foothills and 800 boe/d of production in Northeast BC. These properties were shut-in during June 2025 as AECO prices weakened and Northeast BC was again reactivated during the fourth quarter of 2025.

Shut-in production in CAB, representing approximately 8,000 boe/d or 24% of the Company’s production capability, was shut-in during the third quarter of 2024 and is expected to remain shut-in at least through 2026, with the exception of certain non-operated wells in the area; production from CAB does not flow to a Cavvy owned and operated gas processing facility and is tied to high cost, non-operated, non-owned gas processing facilities where Cavvy is fully exposed to operating and maintenance turnaround costs on a ‘flow-through’ basis. These properties have been reclassified as proved developed non-producing (“PDNP”) within the total proved (“TP”) reserve category in the Company’s December 31, 2025 reserve report.

Discretionary shut-ins impacted production as follows at December 31, 2025:

	Production (boe/d)
CAB	8,021
Northern Alberta	707
Current Discretionary Shut-In Production	**8,728**

2025 GUIDANCE IN REVIEW

Cavvy released initial 2025 outlook in December 2024. During 2025, NOI and operating netback guidance were increased to reflect higher third-party processing and marketing revenue, strong sulphur prices, realized hedging gains and the hedge monetization, as follows:

	2025 Guidance – December 2024		2025 Guidance – Revised September 2025		2025 Actual
($ 000s unless otherwise noted)	Low	High	Low	High	Results
Total production (boe/d) (1)	23,000	25,000	23,000	25,000	**23,904**
Net operating income (2)(4)(5)	$75,000	$95,000	$100,000	$110,000	**$110,457**
Operating netback ($/boe) (3)(4)(5)	$9.00	$11.00	$11.50	$12.50	**$12.66**
Capital expenditures (6)	$25,000	$30,000	$25,000	$30,000	**$23,359**

(1) 2025 production guidance assumes persistence of previously announced shut-ins in CAB and periodic, price dependent production of previously announced shut-in volumes in Northern AB and Northeast BC through 2025.
(2) Refer to the "Net Operating Income" and "Non-GAAP and Other Financial Measures" sections of this MD&A for the composition and definition of this non-GAAP financial measure.
(3) Refer to "Operating Netback" and "Non-GAAP and Other Financial Measures" sections of this MD&A for reference to this non-GAAP financial ratio.
(4) Assumes average unhedged 2025 AECO price of $1.61/GJ and average unhedged 2025 WTI price of USD $65.55/bbl.
(5) Revised guidance includes the impact of hedge contracts in place at November 6, 2025.
(6) Capital expenditures guidance excludes reclamation and abandonment activity.

The Company met 2025 production guidance and exceeded revised NOI and operating netback guidance. 2025 capital expenditures were slightly less than guidance due to ongoing capital maintenance cost reduction initiatives and timing of certain planned fourth quarter abandonment and reclamation activities.

2026 OUTLOOK

The Company's 2026 guidance is as follows:

	2026 Guidance	
($ 000s unless otherwise noted)	Low	High
Total production (boe/d) (1)	22,000	24,500
Sulphur production (mt/d)	1,000	1,150
Net operating income (2) (3) (4)	$125,000	$140,000
Capital expenditures (5)	$35,000	$40,000
Total debt at year end 2026 (6)	$110,000	$125,000

(1) Production guidance assumes persistence of previously announced shut-ins in Central AB and Northern AB, while production in Northeast BC is assumed to be on-production through periods with supporting AECO pricing in 2026.
(2) Refer to the "Net Operating Income" and "Non-GAAP and Other Financial Measures" sections of this MD&A for the composition and definition of this non-GAAP financial measure.
(3) Assumes unhedged average 2026 AECO price of $3.15/GJ, average unhedged 2026 WTI price of USD $60.90/bbl and average unhedged 2026 Vancouver FOB sulphur price of USD $237.50/mt.
(4) Includes the impact of hedge contracts and the 2026 Sulphur Pricing Agreement.
(5) Excludes asset retirement and decommissioning expenses.
(6) Assumes USD to CAD exchange rate of 0.7210.

Momentum maintained from key milestones achieved in 2025 including operating cost reduction, third-party processing volume and revenue growth, and sustained risk management initiatives is expected to contribute to strong cash flow and material debt reduction in 2026. These support management's increasing focus on identifying accretive growth opportunities in 2026, consistent with the Company's long-term objective to replenish and grow its reserves and production base and enhance its inventory of investment opportunities.

Specific priorities for 2026 are:

- Sustain a safe and regulatory compliant business
- Capture additional opportunities to grow third-party gathering and processing business value

- Minimize facility outages to maximize sales and processing revenue
- Reduce long-term debt to improve financial flexibility and position the Company to refinance its 2027 debt maturities
- Identify and high-grade both organic and acquisition opportunities that replenish Cavvy's resource base and increase development upside

Production

Production guidance of 22,000 to 24,500 boe/d and 1,000 to 1,150 mt/d of sulphur assumes the continued shut-in of uneconomic dry gas production in CAB and Northern AB for the year, accounting for approximately 8,900 boe/d and 300 mt/d of sulphur, along with seasonal production of Northeast BC volumes as natural gas prices allow.

Production guidance also includes a planned six-week major maintenance turnaround at the Caroline Facility scheduled for the third quarter of 2026, and two weeks of unavoidable downtime at the Waterton Facility related to a scheduled maintenance outage on the TC Energy Nova Gas Transmission Ltd. System ("NOVA") sales gas transportation system anticipated for the second quarter of 2026.

Capital Program

Cavvy's $35.0 million to $40.0 million capital guidance includes $15.0 million to $20.0 million allocated to a scheduled maintenance turnaround at the Caroline Facility in the third quarter of 2026, $9.5 million to capital maintenance including overhauls and long lead procurement for future turnarounds, $3.5 million to facility optimization projects, $5.0 million to ongoing investment in IT and plant control system upgrades, and the remainder for capital maintenance and corporate expenditures. Capital guidance excludes $8.0 million planned expenditure on asset retirement and reclamation activities.

Net Operating Income

Cavvy expects continued growth in third-party processing volumes and revenue at the Caroline and Jumping Pound Facilities. In the fourth quarter of 2025 the Company entered into a multi-year take-or-pay agreement with an anchor processing customer at the Caroline Facility and has successfully contracted additional third-party volumes at the Jumping Pound Facility resulting from the permanent shutdown of a nearby third-party gas processing facility, which began processing its re-directed raw gas production to the Jumping Pound Facility in January 2026. Additionally, Cavvy continues to re-melt and process third-party sulphur at the Shantz sulphur facility, which further contributes to stable, fee-based revenue streams. This growth of the third-party processing business, hedged 2026 hydrocarbon and sulphur revenue, and continued reliable operation of major gas processing facilities underpins management's 2026 NOI guidance of $125.0 to $140.0 million.

2026 NOI guidance assumes an unhedged Vancouver FOB sulphur price averaging US$250/mt for the first half of 2026 and US$225/mt for the second half of 2026, an average unhedged 2026 AECO price of $3.15/GJ, and an average unhedged 2026 WTI price of USD $60.90/bbl.

Recent months have experienced price variances on certain commodities when compared to 2026 guidance assumptions, partially driven by increased demand in other sectors and now global trade flow disruptions from the war in the Middle East. Spot sulphur has remained elevated at approximately USD $498/mt year-to-date, while AECO has been unexpectedly weak for the winter season at $1.92/GJ year-to-date. Management is encouraged by the continued strength in the spot sulphur market and expects net sulphur margins to contribute a larger proportion of revenue to 2026 NOI targets. Recent volatility and uncertainty in the global markets as a result of geo-political instability may continue, and Cavvy will monitor these events to effectively manage risks and opportunities that may arise.

FUNDS FLOW FROM OPERATIONS

The following table summarizes the Company's funds flow from operations ("FFO") for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31		Year ended December 31	
($ 000s)	2025	2024	2025	2024
Cash provided by (used in) operating activities	**7,776**	(592)	**36,453**	7,132
Settlement of decommissioning obligations	**5,765**	559	**7,431**	5,549
Changes in non-cash working capital	**(23)**	3,374	**18,741**	6,434
Funds Flow from Operations	**13,518**	3,341	**62,625**	19,115

(1) Refer to "Non-GAAP and Other Financial Measures" section of this MD&A for the definition of FFO.

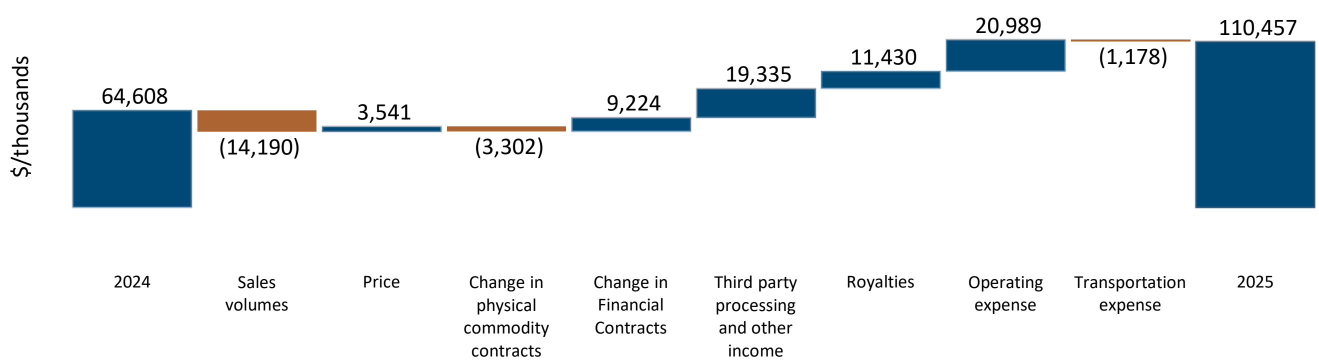
NET OPERATING INCOME

The following table summarizes the Company's NOI for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
($ 000s)	2025	2024	% Change	2025	2024	% Change
Revenue before Risk Management Contracts	**48,939**	41,693	17	**184,719**	195,368	(5)
Gain on physical commodity contracts	**597**	1,084	(45)	**3,248**	6,550	(50)
Realized gains on Financial Contracts (1)(2)	**12,219**	16,989	(28)	**76,443**	67,219	14
Revenue after Risk Management Contracts	**61,755**	59,766	3	**264,410**	269,137	(2)
Processing, marketing and other revenue (3)	**12,780**	5,556	130	**40,189**	20,854	93
Revenue	**74,535**	65,322	14	**304,599**	289,991	5
Royalties	**(5,078)**	(4,701)	8	**(10,241)**	(21,671)	(53)
Operating	**(43,687)**	(42,797)	2	**(164,758)**	(185,747)	(11)
Transportation	**(4,985)**	(4,104)	21	**(19,143)**	(17,965)	7
Net Operating Income (4)	**20,785**	13,720	51	**110,457**	64,608	71

(1) Includes gains or losses on financial risk management contracts and cash flow hedges, together ("Financial Contracts").
(2) The year ended period ended December 31, 2025 includes the early monetization of certain AECO natural gas contracts for proceeds of $10.2 million net of transaction costs.
(3) Other revenue includes road use income and contract operating income.
(4) Refer to "Non-GAAP and Other Financial Measures" section of this MD&A for the definition of NOI.

Year-over-Year Net Operating Income Component Variance

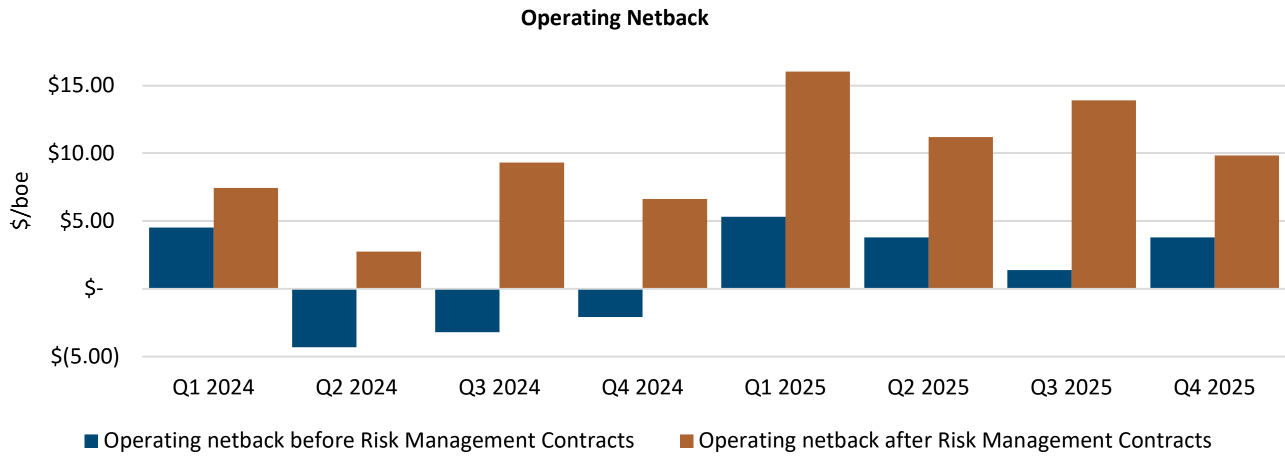


OPERATING NETBACK

The following table summarizes the Company's operating netback for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
($ per boe)	2025	2024	% Change	2025	2024	% Change
Revenue before Risk Management Contracts	**23.12**	20.08	15	**21.17**	19.23	10
Gain on physical commodity contracts	**0.28**	0.52	(46)	**0.36**	0.64	(44)
Realized gains on Financial Contracts	**5.77**	8.18	(29)	**8.76**	6.61	33
Revenue after Risk Management Contracts	**29.17**	28.78	1	**30.29**	26.48	14
Processing, marketing and other revenue (1)	**6.05**	2.68	126	**4.61**	2.05	125
Revenue	**35.22**	31.46	12	**34.90**	28.53	22
Royalties	**(2.40)**	(2.26)	6	**(1.17)**	(2.13)	(45)
Operating	**(20.64)**	(20.61)	-	**(18.88)**	(18.28)	3
Transportation	**(2.36)**	(1.98)	19	**(2.19)**	(1.77)	24
Operating netback ($/boe) (2)	**9.82**	6.61	49	**12.66**	6.35	99

(1) Other revenue includes transportation and gathering income.
(2) Refer to "Non-GAAP and Other Financial Measures" section of this MD&A for the definition of operating netback.



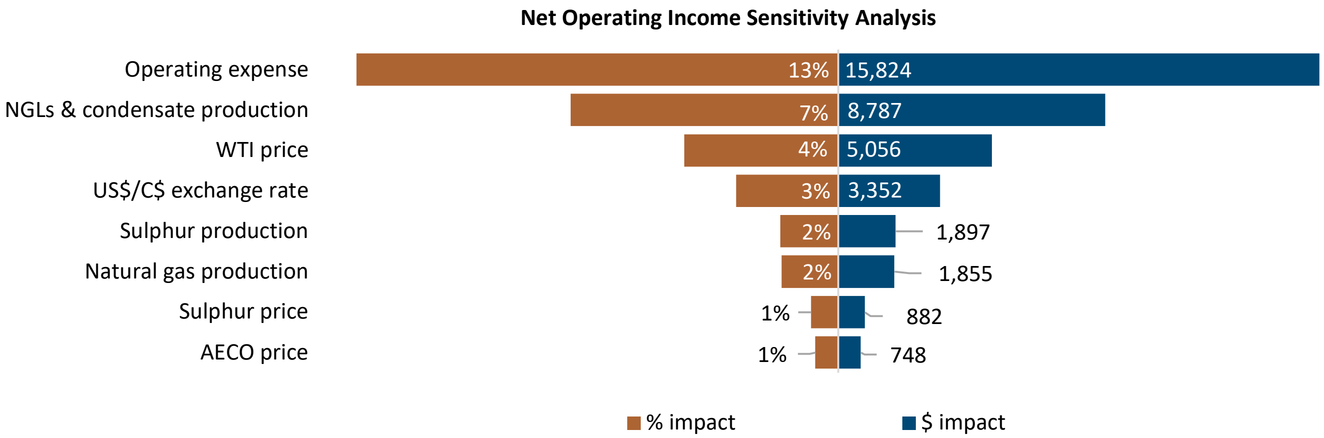
NET OPERATING INCOME SENSITIVITY ANALYSIS

The following table summarizes the Company's NOI sensitivity for the three months and years ended December 31, 2025:

	Three months ended December 31				Year ended December 31			
	2025	% Change	$ Impact	% Impact	2025	% Change	$ Impact	% Impact
Business Environment (1)(2)								
WTI price (USD/bbl) (3)	59.21	10	939	5	64.93	10	5,056	4
AECO price ($/mcf) (4)	2.25	10	228	1	1.68	10	748	1
Sulphur price (USD/mt)	414.47	10	230	1	285.35	10	882	1
USD/CAD average exchange rate (5)	0.7174	10	530	3	0.7159	10	3,352	3
Operational (1)(6)(7)								
NGLs & condensate production (bbl/d)	4,364	10	1,732	8	4,782	10	8,787	7
Natural gas (mcf/d)	111,834	10	2,438	12	114,730	10	1,855	2
Sulphur production (mt/d)	989	10	540	3	1,078	10	1,897	2
Royalty burden (% of sales revenue)	10%	1	328	2	5%	1	1,234	1
Operating expense ($/boe)	(20.64)	10	4,199	20	(18.88)	10	15,824	13

(1) Calculations are performed independently and may not be indicative of actual results that would occur when multiple variables change simultaneously.
(2) The indicative impact on NOI is only applicable within a limited range of these amounts as royalty burden is held constant.
(3) Includes the impact of WTI price on NGL (C3, C4) and condensate (C5) prices assuming a correlation to USD WTI.
(4) Includes the impact of AECO price on NGL (C2) price assuming a correlation to AECO.
(5) Includes the impact of foreign exchange on NGL and Condensate prices assuming a correlation to USD WTI.
(6) Includes the impact of commodity hedges that were in place during the period.
(7) Operational assumptions are based upon the results for the three and year ended December 31, 2025, and the calculated impact on NOI is only applicable within a limited range of these amounts.

The following chart represents the estimated 2025 NOI impact oof a 10% change in each input variable:

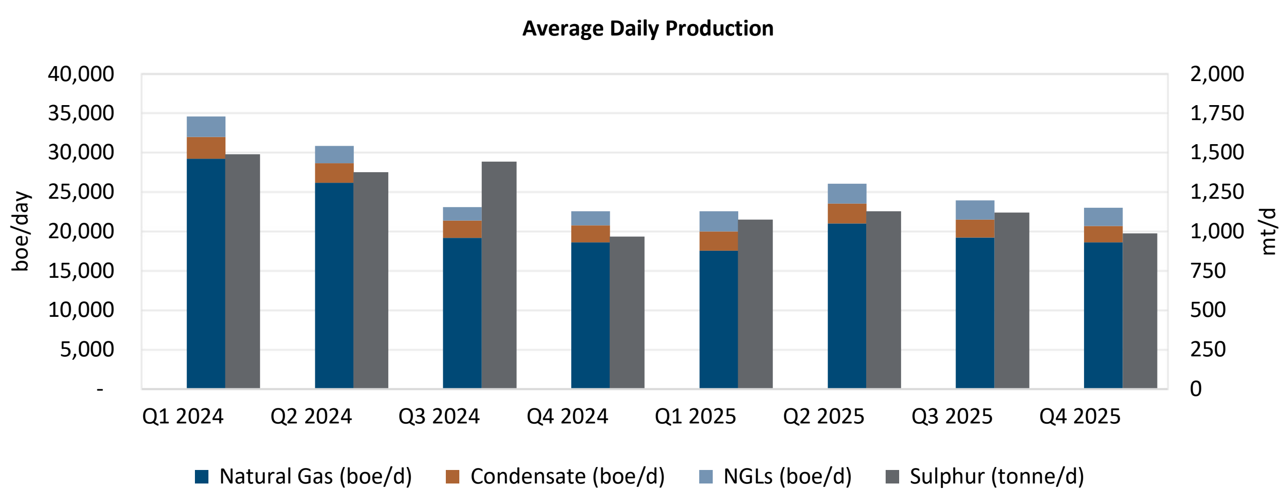


PRODUCTION

The following table summarizes the Company's production by commodity for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
(boe/d)	2025	2024	% Change	2025	2024	% Change
Natural gas (mcf/d)	**111,834**	111,787	(5)	**114,730**	139,710	(18)
Condensate (bbl/d)	**2,065**	2,149	(4)	**2,320**	2,397	(3)
NGLs (bbl/d)	**2,299**	1,788	29	**2,462**	2,081	18
Sulphur (mt/d)	**989**	968	2	**1,078**	1,319	(18)
Total production (boe/d) (1)	**23,003**	22,568	2	**23,904**	27,763	(14)
Natural gas production (%)	**81**	83	n/a	**80**	84	n/a
Liquids production (%)	**19**	17	n/a	**20**	16	n/a

(1) Total production excludes sulphur.

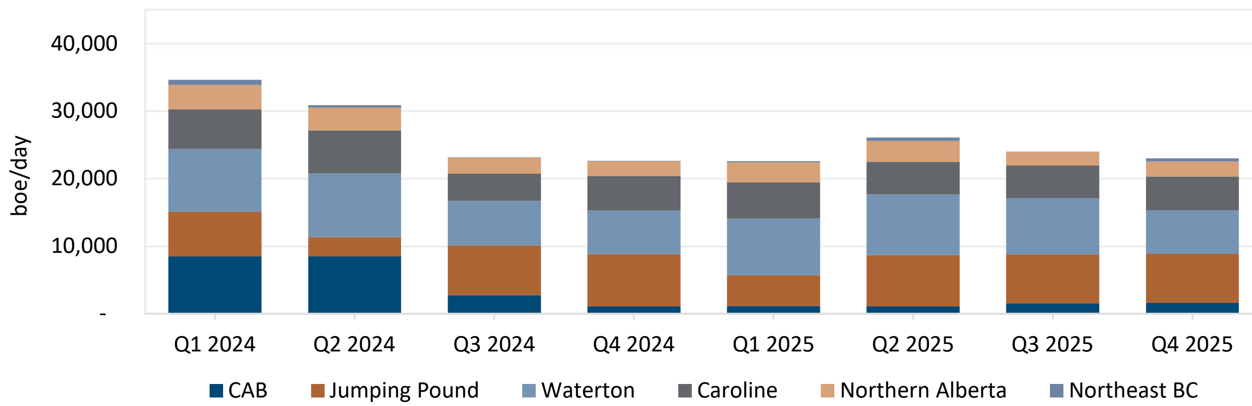


Production By Area

The following table summarizes the Company's production by core area for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
(boe/d)	**2025**	**2024**	**% Change**	**2025**	**2024**	**% Change**
Waterton	**6,448**	6,463	-	**8,032**	7,949	1
Jumping Pound	**7,233**	7,711	(6)	**6,648**	6,134	8
Caroline	**5,015**	5,110	(2)	**5,026**	5,334	(6)
CAB	**1,603**	1,085	48	**1,330**	5,169	(74)
Northern Alberta Foothills	**2,214**	2,179	2	**2,566**	2,887	(11)
Northeast BC	**490**	20	NM	**302**	290	4
Total production (boe/d)	**23,003**	22,568	2	**23,904**	27,763	(14)

Quarterly Production by Area



As discussed in the Highlights section of this MD&A, total production declined year-over-year primarily due to the continued shut-in of volumes in the CAB area which commenced in mid-2024. Other events that impacted quarterly production include:

- Certain non-operated CAB volumes which were shut-in in the fourth quarter of 2024 were restarted through 2025.
- Economic Northeast BC wells were restarted in the fourth quarter of 2025 increasing production for the three-month period.
- Jumping Pound volumes were impacted by field compressor maintenance resulting in higher downtime in the current period.
- Waterton volumes were impacted by planned maintenance outages in the fourth quarter of 2025 and 2024.

RESERVES

Cavvy's qualified independent reserves evaluator, Deloitte LLP, completed the evaluation of the Company's reserves effective December 31, 2025 and 2024 in accordance with NI 51-101. Selected highlights are discussed below and additional information is available in the Company's AIF.

	Year ended December 31 MMboe			Year ended December 31 $000, NPV10 (1)		
	2025	**2024**	**% Change**	**2025**	**2024**	**% Change**
Reserves Category (2)						
Net proved developed producing ("PDP") reserves	**106.6**	114.9	(7)	**711,083**	621,393	14
Net proved ("1P") reserves	**196.2**	183.2	7	**1,173,560**	961,491	22
Net proved plus probable ("2P") reserves	**260.5**	244.3	7	**1,505,907**	1,252,170	20

(1) Estimated pre-tax net present value of discounted cash flows from reserves using a 10% discount rate at evaluator consensus (IC4) price forecast dated January 1, 2026, excluding value of Risk Management Contracts.

(2) Net reserves reflect working interest share of the asset prior to the deduction of royalties.

PDP Reserve Highlights

- 2025 PDP reserves of 106.6 MMboe reflect positive technical revisions related to lower forecast net operating costs allocated to the Company's producing wells due to offsetting third-party gathering and processing revenue at Cavvy's Caroline and Jumping Pound Facilities, demonstrating the successful execution of Cavvy's midstream growth strategy and increasing the economic life of related PDP reserve entities, offset by volume decreases arising from produced reserves and the recategorization of certain prior PDP reserves into PDNP resulting from the extended shut-in of CAB properties.
- 2025 year-end PDP NPV10 of $711 million applies the IC4 price forecast at January 1, 2026 to the PDP reserves forecast and reflects an increase of 14% year over year, primarily due to higher forecast sulphur prices offsetting lower forecast hydrocarbon prices.
- Cavvy's PDP base decline rate decreased from 7.3% in 2024 to 5.9%, representing one of the lowest natural decline rates among peer companies.

1P Reserve Highlights

- 2025 year-end TP reserves of 196.2 MMboe reflect positive technical revisions related to lower forecast net operating costs allocated to the Company's producing wells due to offsetting third-party gathering and processing revenue, partially offset by produced reserves.
- 2025 year-end TP NPV10 of $1,174 million applies the IC4 price forecast at January 1, 2026 to the TP reserves forecast and reflects an increase of 22% year over year, primarily due to higher forecast sulphur prices and positive technical revisions noted above, offsetting lower forecast hydrocarbon prices.
- 29 Proven Undeveloped ("PUD") drilling locations are recognized in the 2025 reserve evaluation, consistent with 2024.

2P Reserve Highlights

- 2025 year-end 2P reserves of 260.5 MMboe reflect positive technical revisions related to lower forecast net operating costs allocated to the Company's producing wells due to offsetting third-party gathering and processing revenue, partially offset by produced reserves.
- 2025 year-end 2P NPV10 of $1,506 million applies the IC4 price forecast at January 1, 2026 to the 2P reserves forecast and reflects an increase of 20% year over year, primarily due to higher forecast sulphur prices and the positive technical revisions noted above, offsetting lower forecast hydrocarbon prices.
- 32 total booked P+PUD drilling locations (3 2P PUD locations) are recognized in 2025 reserve evaluation, consistent with 2024.
- Cavvy remains conservatively booked with a ratio of PDP to 2P reserves of 41% and a ratio of 1P to 2P reserves of 75%.

Additional information and a detailed reconciliation of Cavvy' 2025 NI51-101 reserves is available in the Company's AIF.

Reserve Life Index

The following table outlines the reserve life index for the years ended December 31, 2025 and 2024:

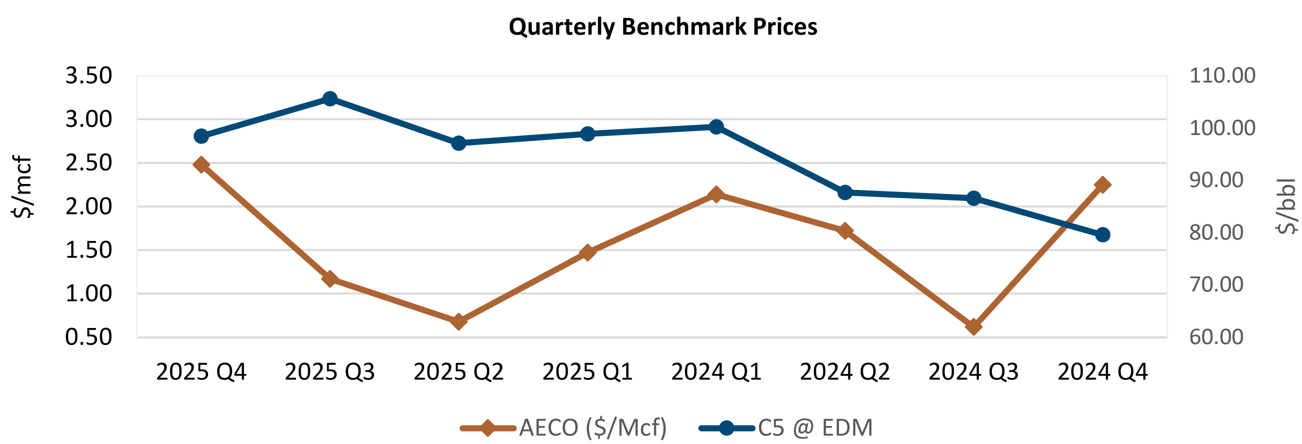
Years	Year ended December 31		
	2025	**2024**	**% Change**
Reserves Category (2)			
PDP reserves	**11.2**	12.4	(10)
1P reserves	**19.6**	19.1	3
2P reserves	**25.8**	25.1	3

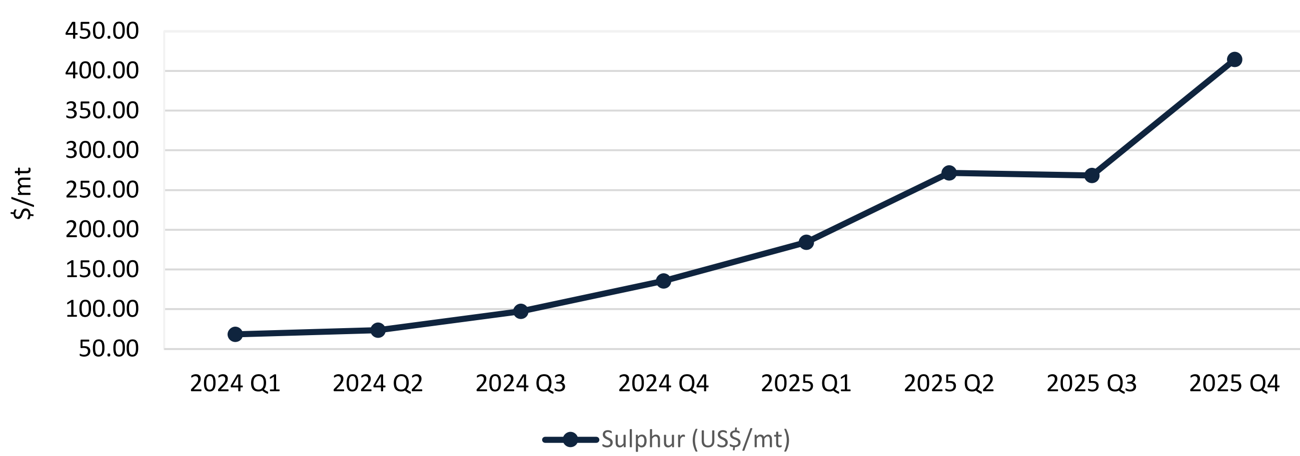
RLI decreased in the PDP reserves category due to the reclassification of certain temporarily shut-in CAB properties to PDNP but increased in the 1P and 2P reserves category due primarily to improved operating costs as described above, and increased sulphur pricing.

BENCHMARK PRICES

The following table summarizes benchmark commodity pricing for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31				Year ended December 31		
	Q4 2025	Q4 2024	% Change	Q3 2025	2025	2024	% Change
Natural Gas							
AECO ($/mcf)	**2.25**	1.46	54	0.62	**1.68**	1.45	16
Henry Hub (USD/MMbtu)	**3.72**	2.43	53	3.03	**3.53**	2.25	57
Chicago Citygate (USD/MMbtu)	**3.38**	2.21	53	2.79	**3.26**	2.10	55
Basis Differential AECO-NYMEX Premium (Discount) (USD/MMbtu)	**(2.10)**	(1.39)	51	(2.58)	**(2.33)**	(1.19)	96
Condensate							
C5 at Edmonton ($/bbl)	**79.61**	98.85	(19)	86.58	**88.54**	100.02	(11)
West Texas Intermediate ("WTI") crude oil (USD/bbl)	**59.21**	70.42	(16)	65.03	**64.93**	75.93	(14)
Sulphur							
Vancouver FOB Sulphur (USD/mt)	**414.47**	135.78	205	268.42	**285.35**	94.04	203
Relevant Foreign Exchange Rates							
USD/CAD average exchange rate	**0.7174**	0.7148	-	0.7262	**0.7159**	0.7301	2





Natural Gas: 100% of natural gas production is priced at AECO. AECO pricing is generally correlated with the Henry Hub and Chicago markets and adjusted for an AECO basis differential related to the transportation of Canadian gas into the US gas transportation system. The increase in AECO pricing during the fourth quarter of 2025 relative to the comparable period reflects an improvement in Western Canadian natural gas fundamentals from the prior year's oversupplied conditions. AECO prices in late 2024 were depressed by mild weather during the winter season, elevated natural gas storage levels, strong regional production and limited takeaway capacity, which constrained access to broader North American markets. During 2025, producers responded to periods of weak pricing and storage pressure through production curtailments, helping to rebalance the market. In addition, seasonal winter demand and the continued commissioning and ramp-up of LNG Canada's Kitimat export facility provided incremental demand support for Western Canadian gas. These factors contributed to stronger pricing in the fourth quarter of 2025 compared to the prior year.

Condensate: The primary market for Cavvy's condensate production into the Edmonton market for use as diluent to reduce the viscosity of heavy oil for transportation through pipelines. Condensate pricing is highly correlated to the WTI crude oil price. During the three months and year ended December 31, 2025, C5 and WTI pricing declined compared to the same periods in the prior year which was largely driven by reduced consumption and market volatility stemming from global trade tensions involving the US.

Sulphur: There are various markets for Cavvy's sulphur production including North American fertilizer manufacturers and mining entities, as well as international markets accessed through Vancouver or Tampa Bay sulphur export terminals. Worldwide sulphur markets are relatively illiquid, with poor price discovery. Typically, contracts are on a one-off basis between counterparties. Currently there are no financial instruments or futures markets which allow a sulphur producer to financially hedge prices, however physical fixed-price or collared contracts can provide price certainty during the contract period, typically not exceeding one or two years. Spot price benchmarks are based on price assessments from actual spot physical sales at the pricing point or implied from a remote pricing point by deducting applicable transportation and handling costs. During the second half of 2025 and the year-to-date, sulphur benchmark prices increased significantly as compared to the same periods in 2024. The sharp increase in sulphur prices in both periods was primarily driven by increased demand in the agriculture and mining sectors which are consumers of sulphur-derived inputs. Supply has also been constrained by maintenance outages, logistical disruptions, and reduced export volumes from key producers, creating tighter market conditions. Shifting trade flows supported sulphur prices throughout the year ended December 31, 2025.

REALIZED PRICES

The following table summarizes the Company's realized pricing for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31				Year ended December 31		
	Q4 2025	Q4 2024	% Change	Q3 2025	2025	2024	% Change
Realized Natural Gas Price							
Before Risk Management Contracts ($/mcf)	**2.41**	1.55	55	0.66	**1.74**	1.58	10
After Risk Management Contracts ($/mcf) (1)	**3.60**	3.36	7	3.25	**3.65**	3.15	16
Realized Condensate Price							
Before Risk Management Contracts ($/bbl)	**76.62**	94.87	(19)	82.65	**85.08**	94.48	(10)
After Risk Management Contracts ($/bbl)	**79.75**	90.61	(12)	83.66	**84.59**	86.73	(2)
NGLs ($/bbl)	**26.59**	35.92	(26)	27.89	**30.27**	33.08	(8)
Sulphur ($/mt) (2)	**43.22**	12.09	257	34.59	**31.68**	13.52	134

(1) The realized price of natural gas after Risk Management Contracts was normalized for the hedge monetization in the first quarter of 2025, which also affects the year ended December 31, 2025.
(2) The realized price of sulphur is net of deductions including transportation, processing and marketing.

The following table outlines volumes sold at spot price versus volumes sold under Risk Management Contracts for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31				Year ended December 31			
	2025		2024		2025		2024	
(% of product volume)	% spot	% hedge	% spot	% hedge	% spot	% hedge	% spot	% hedge
Natural gas	**2**	**98**	5	95	**4**	**96**	21	79
Condensate	**19**	**81**	19	81	**27**	**73**	29	71
NGLs	**100**	**-**	100	-	**100**	**-**	100	-
Sulphur	**12**	**88**	8	92	**14**	**86**	16	84
Total production (1)	**14**	**86**	14	86	**16**	**84**	28	72

(1) Total production excludes sulphur.

Marketing arrangements

Cavvy transacts with various counterparties under several short and long-term agreements to facilitate market access for its products. As a result, the custody transfer point for all products is at or near the relevant Cavvy facility gate.

The Company's hydrocarbon and sulphur sales are subject to various marketing agreements, as follows:

Commodity	Agreement Type	Pricing mechanism	Duration	Custody Transfer Point
Natural gas	Sales (1)	AECO NIT (2)	5a or 7a index	NOVA inlet
NGLs	Marketing	Market less marketing fees	Term, expires Q1 2027	Facility gate
Condensate	Marketing	Market less marketing fees	Annual, expires Q3	Facility gate
Sulphur	Sales (3)	FOB Vancouver less transportation, handling costs, and marketing fees (2)	Term, expires Q4 2028 (4)	Facility gate

(1) Natural gas sold to various counterparties.
(2) Other than volumes sold under fixed price physical sales contracts. Refer to Risk Management Contracts section
(3) Substantially all sulphur production is sold under this agreement.
(4) Buyer holds an option to renew this agreement for one additional year upon their achievement of certain performance criteria.

RISK MANAGEMENT CONTRACTS

The Company's risk management program is governed by its hedge policy. Cavvy's hedge policy is designed to manage risks associated with price volatility in natural gas, condensate, NGLs, sulphur, power, and fluctuations in both interest and foreign exchange rates. Risk management contracts are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. Management continuously reviews the need or requirement to utilize risk management contracts. As at December 31, 2025, future production is hedged in accordance with the thresholds of the Senior Facility agreements.

Financial Contracts are financial derivative instruments. Their impacts are recorded at fair value with changes in fair value and unrealized gains and losses being recognized in net income if hedge accounting is not applied and through other comprehensive income ("OCI") if hedge accounting is applied. Realized gains and losses are recognized in net income. Cavvy classifies AECO natural gas swaps and WTI crude oil collars and swaps as cash flow hedges and applies hedge accounting accordingly. There was no hedge ineffectiveness identified as of December 31, 2025.

Fixed price physical power purchase and various physical commodity sales contracts are recognized in the applicable financial statement line item they are associated with; physical power contracts are recognized in operating expense and physical commodity contracts are recognized in revenue. Physical risk management contracts are not considered to be derivative financial instruments as they are settled based on physical receipt or delivery of the product and therefore are not recorded at fair value.

During the first quarter of 2025, the Company elected to unwind and monetize certain in-the-money AECO natural gas financial contracts, originally scheduled to mature between January 2026 and May 2027. The transaction reduced the Company's hedge position by approximately 30% or 24,862 GJ/d over the 17-month future period. In addition, the strike price on the remaining AECO hedges between June 2026 and May 2027 was adjusted to $3.40/GJ from $3.78/GJ. This monetization transaction resulted in proceeds of $10.2 million, net of transaction costs, which was recognized as a realized gain on financial contracts in March 2025.

The following realized gains or losses were generated from risk management contracts for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
($ 000s)	2025	2024	% Change	2025	2024	% Change
(Loss) gain on physical power contracts	**(4,346)**	(2,158)	101	**(16,870)**	(3,164)	433
(Loss) on physical Legacy Sulphur Pricing Agreement	**(20,902)**	(2,446)	755	**(54,915)**	(13,434)	309
Gain on physical commodity contracts						
AECO	**596**	1,084	(45)	**3,187**	6,550	(51)
Realized gain (loss) on Financial Contracts						
AECO	**11,661**	17,503	(33)	**76,540**	73,686	4
WTI	**594**	(843)	(170)	**(420)**	(6,796)	(94)
Foreign exchange	**(36)**	329	(111)	**323**	329	(2)
Total realized gain on risk management contracts	**(12,433)**	13,649	(191)	**7,845**	57,171	(86)

The following unrealized gains or losses were generated from Financial Contracts for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
($ 000s)	2025	2024	% Change	2025	2024	% Change
Unrealized gain (loss) on Financial Contracts (1)						
Foreign exchange	-	520	(100)	**(520)**	520	(200)
Unrealized (loss) gain on Financial Contracts, net of tax (2)						
AECO	**(2,601)**	(3,946)	(34)	**(40,107)**	5,600	(816)
WTI	**3,992**	(6,455)	(162)	**13,934**	(3,481)	(500)
Total unrealized gain (loss) on Financial Contracts (3)	**1,391**	(9,881)	(114)	**(26,693)**	2,639	(1,111)

(1) Recognized in net income (loss) on the Consolidated Financial Statements.
(2) Recognized in OCI on the Consolidated Financial Statements.
(3) Unrealized gains on Financial Contracts include financial risk management contracts inclusive of cash flow hedges and are net of tax.

The following fixed price physical commodity sales contracts and power contracts were in place at December 31, 2025:

Type of contract	Average Quantity	Time Period	Average Contract Price
Fixed Price - Natural Gas Sales	8,000 GJ/d	Jan 2026	CAD $3.37/GJ
Fixed Price - Natural Gas Sales	5,000 GJ/d	Feb 2026 - Oct 2026	CAD $3.31/GJ
Fixed Price - Power Purchases	55 MW	Jan 2026 - Dec 2026	CAD $71.80/MWh
Fixed Price - Power Purchases	33 MW	Jan 2027 - Dec 2027	CAD $67.68/MWh
Fixed Price - Sulphur Sales	1/3 of Sulphur Sales	Jan 2026 – Dec 2026	USD $225/mt
Collar - Sulphur Sales	1/3 of Sulphur Sales	Jan 2026 – Dec 2026	USD $205.00 - $250.00/mt

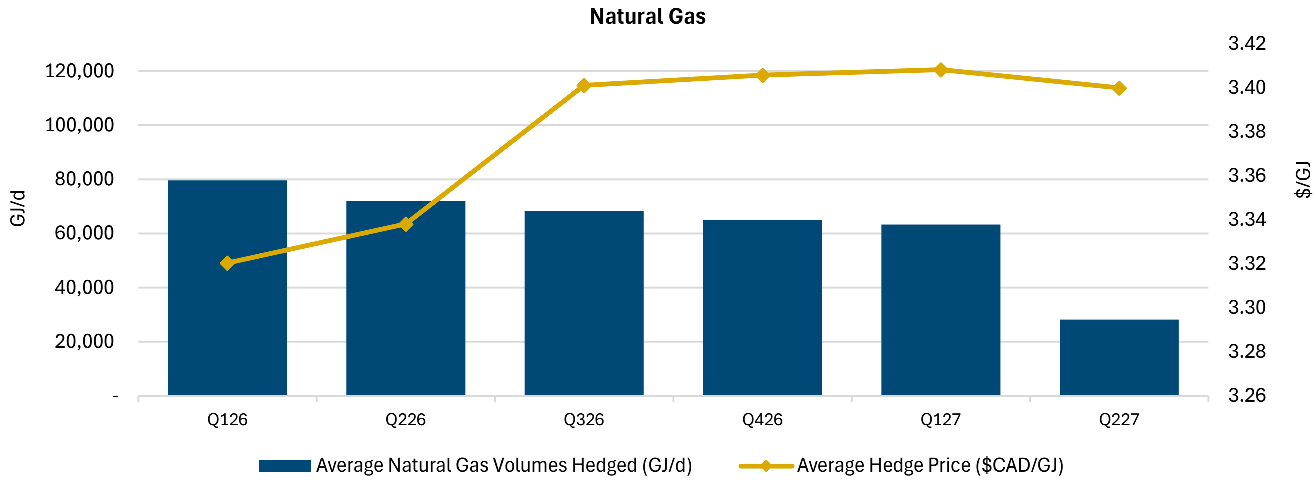
The following Financial Contracts, which hedge accounting was applied, were in place at December 31, 2025:

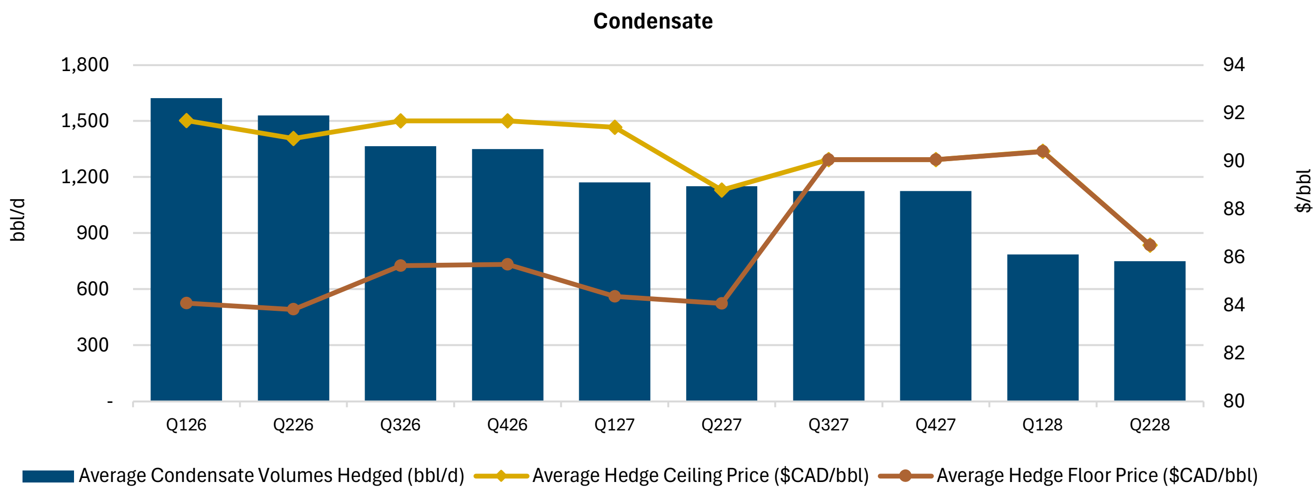
Type of contract	Average Quantity	Time Period	Average Contract Price
AECO Natural Gas Swap	73,500 GJ/d	Jan 2026 - May 2026	CAD $3.32/GJ
AECO Natural Gas Swap	53,340 GJ/d	Jun 2026	CAD $3.40/GJ
AECO Natural Gas Swap	63,340 GJ/d	Jul 2026 - Mar 2027	CAD $3.41/GJ
AECO Natural Gas Swap	42,000 GJ/d	Apr 2027 - May 2027	CAD $3.40/GJ
WTI Crude Oil Collar	917 bbl/d	Jan 2026 - Dec 2026	CAD $80.00 - $90.75/bbl
WTI Crude Oil Collar	761 bbl/d	Jan 2027 - May 2027	CAD $80.00 - $90.75/bbl
WTI Crude Oil Swap	549 bbl/d	Jan 2026 - Dec 2026	CAD $92.82/bbl
WTI Crude Oil Swap	828 bbl/d	Jan 2027 - Dec 2027	CAD $90.57/bbl
WTI Crude Oil Swap	768 bbl/d	Jan 2028 - Jun 2028	CAD $88.45/bbl

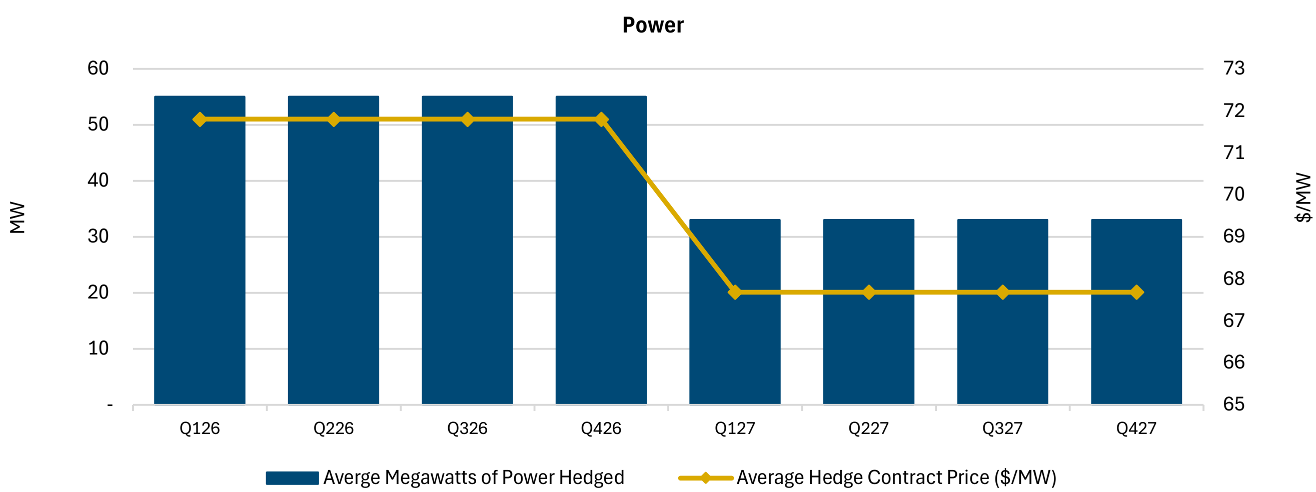
The following Risk Management Contracts were entered into subsequent to December 31, 2025:

Type of contract	Average Quantity	Time Period	Average Contract Price
Fixed Price - Power Purchases	8 MW	Jan 2027 - Dec 2027	CAD $53.01 /MWh
Fixed Price - Power Purchases	10 MW	Jan 2028 - Dec 2028	CAD $61.00 /MWh
WTI Crude Oil Swap	250 bbl/d	Oct 2026 - Dec 2026	CAD $86.10 /bbl
WTI Crude Oil Swap	650 bbl/d	Jan 2027 - Mar 2027	CAD $89.27 /bbl
WTI Crude Oil Swap	400 bbl/d	Apr 2027 - Dec 2027	CAD $91.25 /bbl
WTI Crude Oil Swap	600 bbl/d	Jan 2028 - Dec 2028	CAD $86.17 /bbl
WTI Crude Oil Swap	600 bbl/d	Jan 2029 - Dec 2029	CAD $84.67 /bbl

The following charts outline Cavvy's hedge position December 31, 2025:







PETROLEUM AND NATURAL GAS REVENUE

The following table summarizes the Company's revenue for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
($ 000s except per boe)	**2025**	**2024**	**% Change**	**2025**	**2024**	**% Change**
Natural gas	**25,421**	17,038	49	**76,255**	87,295	(13)
Condensate	**14,556**	18,754	(22)	**72,042**	82,879	(13)
NGLs	**5,625**	5,908	(5)	**27,200**	25,216	8
Sulphur	**3,933**	1,077	265	**12,470**	6,528	91
Petroleum and natural gas revenue (1)	**49,535**	42,777	16	**187,967**	201,918	(7)
Realized gain on Financial Contracts	**12,220**	16,989	(28)	**76,443**	67,219	14
Commodity revenue including Risk Management Contracts	**61,755**	59,766	3	**264,410**	269,137	(2)
Petroleum and natural gas revenue ($/boe)	**23.41**	20.60	14	**21.54**	19.87	8

(1) Petroleum and natural gas revenue includes gains and losses on physical commodity contracts.
(2) Other revenue includes road use income and operating income contract.

Petroleum and natural gas revenue is derived from the sale of natural gas, condensate, NGLs and sulphur. Fluctuations in revenue occur due to production variability and commodity price volatility which is mitigated through the Company's hedge policy.

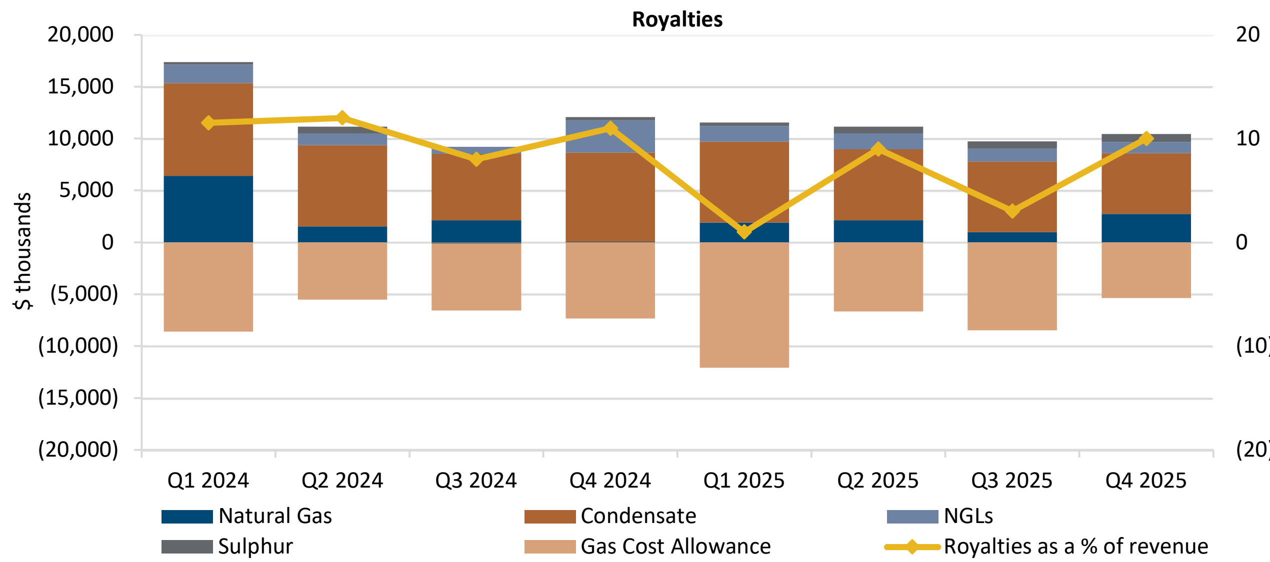
ROYALTIES

The following table summarizes the Company's royalty obligations for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
($ 000s except per boe)	**2025**	**2024**	**% Change**	**2025**	**2024**	**% Change**
Gross royalties	**10,441**	12,051	(13)	**42,834**	49,606	(14)
Gas cost allowance	**(5,363)**	(7,350)	(27)	**(32,593)**	(27,935)	17
Royalties	**5,078**	4,701	8	**10,241**	21,671	(53)
Royalties ($/boe)	**2.40**	2.26	6	**1.17**	2.13	(45)
Royalties as percentage of revenue (%)	**10**	11	(9)	**5**	11	(55)

Cavvy pays royalties to the Alberta and BC Crown ("Crown"), Indian Oil and Gas Commission ("IOGC"), and to various freehold and gross overriding royalty owners. Gross natural gas royalties are reduced by Gas Cost Allowance ("GCA"), which is provided by the Crown and IOGC to account for operating and capital expenses incurred to process and transport their royalty portion of natural gas production.

For the three months ended December 31, 2025, gross royalties and GCA decreased primarily due to lower commodity pricing in 2025 compared to 2024, GCA also decreased due to revisions to the prior period GCA estimate. For the year ended December 31, 2025 gross royalties decreased, primarily due to lower volumes and pricing compared to the prior year. GCA increased during the year ended December 31, 2025 due to revisions to underlying estimates.



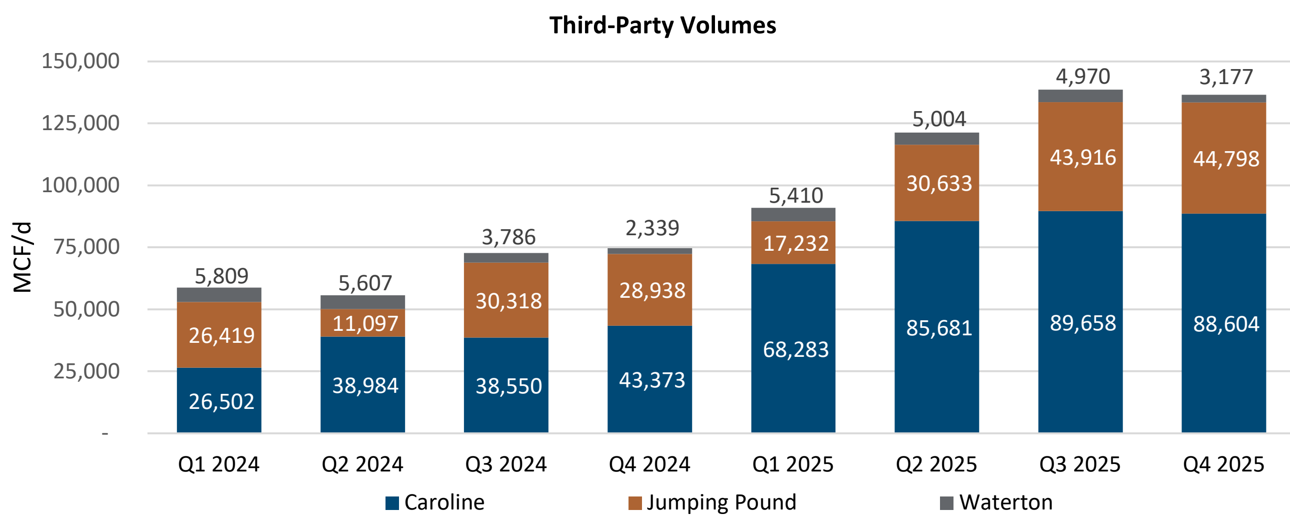
PROCESSING AND MARKETING VOLUMES

Cavvy owns and operates three gas processing facilities and related infrastructure located in southwest Alberta. In addition to Cavvy's produced volumes, these facilities process working interest owner production and third-party production and offer various services including raw gas sweetening, deep-cut NGL recovery, NGL fractionation, sulphur processing, and product marketing.

The following table summarizes the gross raw inlet third-party volumes processed by facility for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
(mcf/d) [1]	2025	2024	% Change	2025	2024	% Change
Caroline	**88,604**	43,373	104	**83,130**	36,875	125
Jumping Pound	**44,798**	28,938	55	**34,247**	24,223	41
Waterton	**3,177**	2,339	36	**4,636**	4,377	6
Total	**136,579**	74,650	83	**122,013**	65,475	86

(1) Volumes shown are reported on a raw basis by activity month, which does not include timing differences due to accounting accruals.



Processing and marketing volumes in 2025 were influenced by:

- Increased third-party volume additions at both the Caroline and Jumping Pound Facilities, reflecting continued commercial success in securing new processing customers and consolidating gas volumes from competing facilities.
- Jumping Pound Facility volumes were impacted in the second quarter of 2024 and the first quarter of 2025 by unplanned maintenance which reduced comparative throughput.

PROCESSING AND MARKETING REVENUE

Processing and marketing revenue is primarily derived from fees charged to third parties for processing and handling their produced volumes through the gas processing facilities.

The following table summarizes the Company's processing and marketing revenue by area for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
($ 000s except per boe)	2025	2024	% Change	2025	2024	% Change
Caroline	**3,965**	871	355	**17,217**	5,707	202
Jumping Pound	**8,110**	3,926	107	**18,511**	11,212	65
Waterton	**347**	392	(11)	**2,440**	2,459	(1)
Other [(1)]	**180**	164	10	**604**	810	(25)
Total	**12,602**	5,353	135	**38,772**	20,188	92

(1) Other contains third-party processing and transportation revenue that is not related to the three major gas processing facilities.

For the three months and year ended December 31, 2025 processing and marketing revenue increased by 135% and 92%, respectively. The increase in revenue is tied to additional third-party volumes, as previously discussed. Processing and marketing revenue is also influenced by market prices for G&P and marketing services, which are subject to various industry conditions.

During the fourth quarter of 2025 Cavvy entered into a multi-year take-or-pay agreement with an anchor processing customer at the Caroline Facility. Due to the growth of Cavvy's third-party processing business, utilization at the Caroline Facility is approaching nameplate capacity. As a result, Cavvy is evaluating further debottlenecking opportunities.

OPERATING EXPENSE

The following table summarizes the Company's operating expense for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
($ 000s except per boe)	2025	2024	% Change	2025	2024	% Change
Operating expense	**43,687**	42,797	2	**164,758**	185,747	(11)
Operating expense ($/boe)	**20.64**	20.61	-	**18.88**	18.28	3

Operating expense slightly increased in the fourth quarter 2025 compared with 2024 due primarily to higher average price of electricity and increased power consumption. For the year ended December 31, 2025, operating expense decreased by 11%, primarily due to lower processing costs incurred following the voluntary production shut-ins, lower realized carbon compliance costs, and various other operating expense reductions related to ongoing cost reduction efforts, partially offset by higher power costs related to both higher realized power prices and increased power consumption driven by higher gathering system and facility utilization.

Cavvy remains committed to reducing operating costs, in absolute and on a per boe basis, through cost reduction initiatives and by increasing facility throughput volumes. Ongoing and future cost reduction efforts are focused on:

- Reducing fuel gas consumption in the field and in facilities. Lower fuel gas use increases natural gas sales and decreases carbon emission intensity and associated emission compliance costs.
- Reducing power consumption through optimization while continuing to hedge power price exposure.
- Reducing dependence on third-party contractors for routine operations by training and empowering employees.
- Centralizing contracting and procurement and deploying category management to ensure efficiencies and economies of scale in the supply chain.
- Optimizing maintenance activities and costs while maintaining and improving operating reliability.

Adjusted Operating Expense

Cavvy incurs a significant component of total operating expense at its three deep cut sour processing facilities. These facilities are more complex and costly to operate than similar sweet-gas processing facilities because they offer acid gas extraction, deep-cut NGL recovery, NGL fractionation (at two of the three), and sulphur recovery. Processing third-party volumes does not add materially to the cost of operating the Company's gas processing facilities, in some cases additional volumes decrease absolute cost through process efficiency. Due to the high proportion of fixed operating costs, volume changes are highly impactful to per boe values.

As Cavvy's third-party processing business grows, the corresponding percentage of Cavvy-owned inlet gas decreases. As the percentage of Cavvy-owned inlet gas decreases, corporate operating expense per boe becomes a less useful measure of cost efficiency or of Cavvy's industry comparability because this calculation does not account for third-party owned gas or sulphur production, both of which contribute to operating netback. As a result, management calculates adjusted operating expense by netting third-party processing and sulphur revenue from operating expense, to more closely align Cavvy's operating expense to peer comparables.

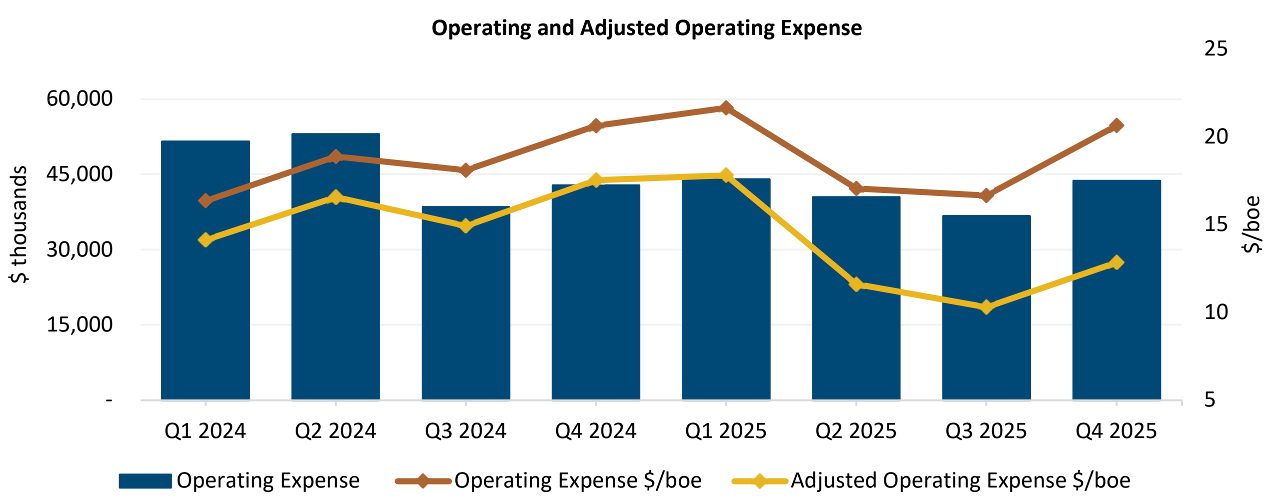
The following table outlines the facility utilization at Cavvy's three deep cut sour processing facilities for the three months end December 31, 2025 and 2024:

(Facility utilization %)	Three months ended December 31, 2025			Three months ended December 31, 2024		
	Caroline	Jumping Pound	Waterton	Caroline	Jumping Pound	Waterton
Cavvy	**29**	52	96	**44**	64	98
Other Owner	**5**	-	-	**9**	-	-
Third-Party	**67**	48	4	**47**	36	2

The following table outlines the facility utilization at Cavvy's three deep cut sour processing facilities for the years ended December 31, 2025 and 2024:

(Facility utilization %)	Year ended December 31, 2025			Year ended December 31, 2024		
	Caroline	Jumping Pound	Waterton	Caroline	Jumping Pound	Waterton
Cavvy	**30**	57	96	**47**	63	96
Other Owner	**6**	-	-	**10**	-	-
Third-Party	**64**	43	4	**43**	37	4

By disclosing adjusted operating expense, Cavvy is able to better demonstrate the significant value of its owned infrastructure, and the growing importance of sulphur production and third-party processing and marketing revenue to NOI.



The following table summarizes the Company's adjusted operating expense by area for the three months ended December 31, 2025:

Three months ended December 31 *($ per boe)*	**Caroline**	**Jumping Pound**	**Waterton**	**Other [(1)]**	**Total**
Operating expense	32.24	16.53	21.08	13.38	**20.64**
Less:					
Processing and marketing revenue [(2)]	8.59	12.19	0.59	0.45	**5.95**
Sulphur revenue	2.08	0.84	2.88	1.80	**1.86**
Adjusted operating expense [(3)] - 2025	**21.57**	**3.50**	**17.61**	**11.13**	**12.83**
Adjusted operating expense [(3)] - 2024	**12.15**	**9.99**	**18.67**	**11.62**	**17.52**

(1) Other is made up of CAB, Northern Alberta Foothills and Northeast BC, these areas were impacted by voluntary shut-ins in the three month and year periods.
(2) Caroline and Jumping Pound Facility revenue was impacted in the fourth quarter by prior period equalization settlements.
(3) Refer to "Non-GAAP and Other Financial Measures" section of this MD&A for the definition of adjusted operating expense.

The following table summarizes the Company's adjusted operating expense by area for years ended December 31, 2025:

Twelve months ended December 31 *($ per boe)*	**Caroline**	**Jumping Pound**	**Waterton**	**Other [(1)]**	**Total**
Operating expense	28.48	17.66	15.60	15.62	**18.88**
Less:					
Processing and marketing revenue	9.38	7.63	0.83	0.39	**4.44**
Sulphur revenue	2.20	0.65	1.75	1.12	**1.43**
Adjusted operating expense [(2)] - 2025	**16.90**	**9.38**	**13.02**	**14.11**	**13.01**
Adjusted operating expense [(2)] - 2024	**13.81**	**12.69**	**14.46**	**20.26**	**15.69**

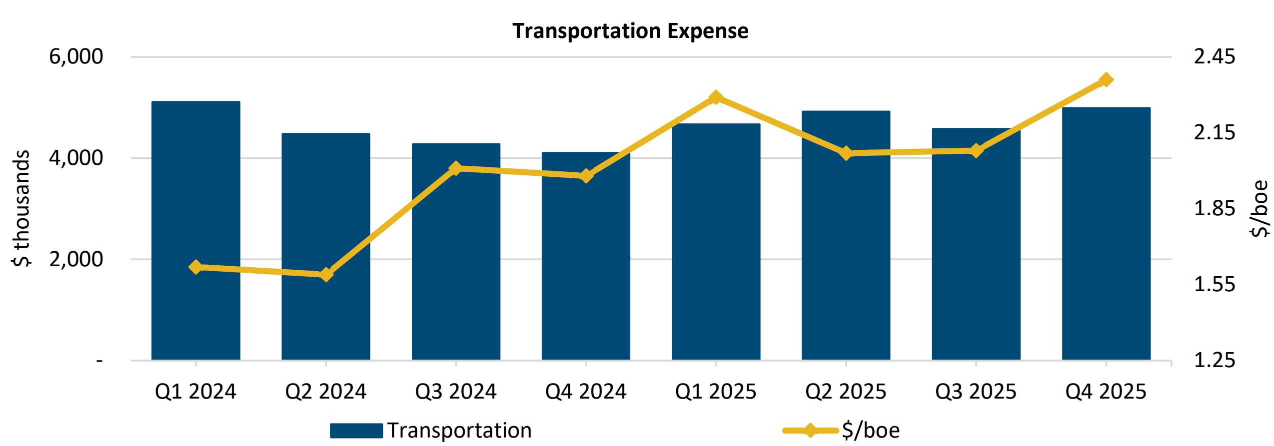
(1) Other is made up of CAB, Northern Alberta Foothills and Northeast BC, these areas were impacted by voluntary shut-ins in the three month and year periods.
(2) Refer to "Non-GAAP and Other Financial Measures" section of this MD&A for the definition of adjusted operating expense.

TRANSPORTATION EXPENSE

The following table summarizes the Company's transportation expense for the three months and years ended December 31, 2025, and 2024:

($ 000s except per boe)	**Three months ended December 31**			**Twelve months ended December 31**		
	2025	**2024**	**% Change**	**2025**	**2024**	**% Change**
Transportation expense	**4,985**	4,104	21	**19,143**	17,965	7
Transportation expense ($/boe)	**2.36**	1.98	19	**2.19**	1.77	24

Substantially all of Cavvy's natural gas production is shipped under firm service transport contracts, which provide Cavvy guaranteed fixed cost access to firm pipeline transportation capacity. Transportation expense is partially influenced by the cost of fuel gas, which is based on AECO pricing. Transportation expense for the quarter ended December 31, 2025 increased on a total and per boe basis primarily due to higher volumes in the current periods. Transportation expense per boe increased during the year ended December 31, 2025 primarily due to the voluntary shut-in of uneconomic production.

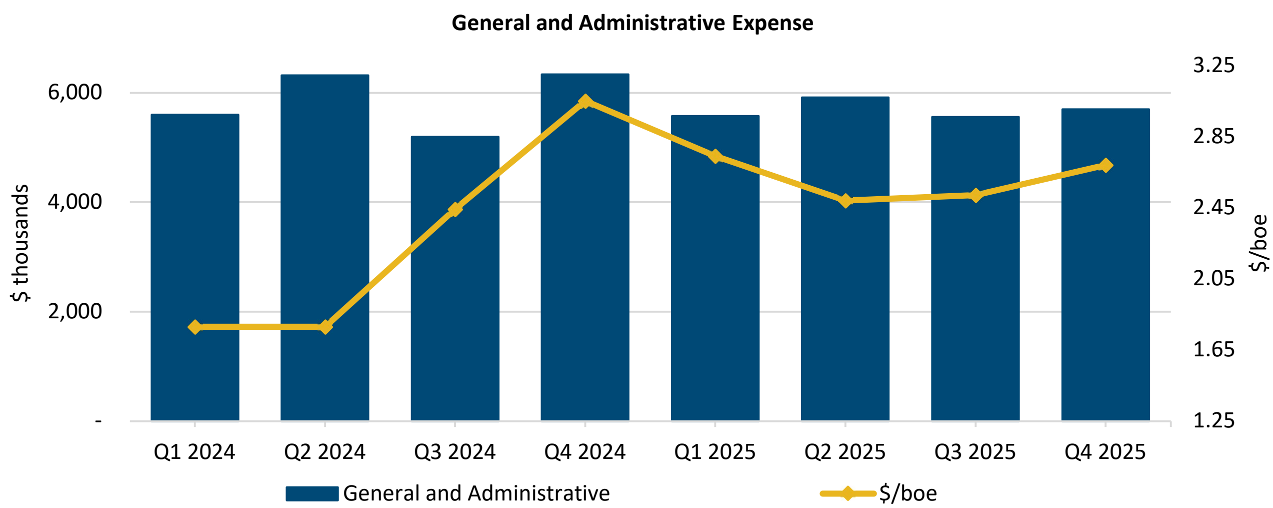


GENERAL AND ADMINISTRATIVE EXPENSE

The following table summarizes the Company's general and administrative ("G&A") expense for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
($ 000s except per boe)	**2025**	**2024**	**% Change**	**2025**	**2024**	**% Change**
General and administrative expense	**5,696**	6,332	(10)	**22,743**	23,438	(3)
General and administrative expense ($/boe)	**2.69**	3.05	(12)	**2.61**	2.31	13

G&A expenses for the quarter ended December 31, 2025 declined on both a total and per boe basis due to larger capital spending resulting in more capitalized G&A costs. On a per boe basis, the year ended December 31, 2025 period is higher due to the voluntary shut-in of uneconomic production.



FINANCE EXPENSE

The following table summarizes the Company's finance expense for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
($ 000s)	**2025**	**2024**	**% Change**	**2025**	**2024**	**% Change**
Cash portion of interest expense	**4,798**	4,453	8	**18,385**	20,853	(12)
Non-cash interest paid in-kind	**-**	1,452	(100)	**1,577**	3,901	(60)
	4,798	5,905	(19)	**19,962**	24,754	(19)
Accretion of financing costs	**1,275**	1,135	12	**4,913**	4,893	-
Accretion of decommissioning obligations	**641**	644	-	**2,590**	2,381	9
Interest on lease liabilities	**137**	186	(26)	**544**	362	50
Other charges	**(42)**	(351)	(88)	**427**	196	118
Total finance expense	**6,809**	7,519	(9)	**28,436**	32,586	(13)

The majority of Cavvy's interest expense relates to variable rate debt tied to the Secured Overnight Financing Rate ("SOFR") plus 6.75%. Total interest expense has declined in both periods due to a combination of lower outstanding debt levels and a reduction in the SOFR rate.

Under the debt facilities, interest is incurred in USD and is subject to fluctuations in the USD/CAD exchange rates.

DEPLETION AND DEPRECIATION

The following table summarizes the Company's depletion and depreciation for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
($ 000s)	**2025**	**2024**	**% Change**	**2025**	**2024**	**% Change**
Depletion and depreciation	**365**	16,015	(98)	**41,057**	59,559	(31)

Depletion and depreciation expense decreased during the three months and year ended December 31, 2025 due to a refinement in the classification type of future development costs included in the depletion base under the unit-of-production method.

SHARE-BASED COMPENSATION

The following table summarizes the Company's share-based compensation for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
($ 000s)	**2025**	**2024**	**% Change**	**2025**	**2024**	**% Change**
Share-based compensation	**3,050**	932	NM	**12,926**	2,403	NM

Share-based compensation is comprised of expense recognized under the Stock Option Plan, Restricted Share Unit ("RSU") Plan and Deferred Share Unit ("DSU") Plan. Share based compensation expense is primarily made up of expenses related to the RSU Plan. Share-based compensation increased in the three months and year ended December 31, 2025 reflecting a higher share price compared to the prior period, resulting in a higher fair value of outstanding units.

RSUs and DSUs are non-dilutive, cash settled and valued based on the five-day volume-weighted average share price and the number of awards outstanding at each reporting period.

TAXES

Deferred income tax assets are recognized to the extent that the realization of the related tax benefit through future taxable profits is probable based on current tax pools and estimated future taxable income. As at December 31, 2025, a deferred tax asset in the amount of $85.0 million (December 31, 2024 – $83.6 million) was recognized as management believes it is probable that the benefit of the associated tax basis will be realized. Included in this tax basis are estimated non-capital loss carry-forwards that expire in the years 2034 through 2045.

The following table summarizes the Company's estimated tax pools at December 31, 2025 and 2024:

($ 000s)	**December 31, 2025**	**December 31, 2024**
Canadian oil and gas property expenses	**143,510**	156,772
Canadian development expenses	**21,646**	25,679
Canadian exploration expenses	**25,381**	25,359
Undepreciated capital costs	**61,091**	54,973
Non-capital and capital losses	**337,400**	350,057
Other	**7,092**	10,831
Estimated tax pools	**596,120**	623,671

CAPITAL EXPENDITURES

The following table summarizes the Company's capital expenditures for the three months and years ended December 31, 2025, and 2024:

	Three months ended December 31			Year ended December 31		
($ 000s)	**2025**	**2024**	**% Change**	**2025**	**2024**	**% Change**
Turnarounds	**2,278**	4,807	(53)	**6,780**	18,210	(63)
Facilities and well optimization	**4,270**	394	NM	**8,698**	3,859	125
Facilities maintenance	**1,124**	-	100	**1,745**	120	NM
Land	**190**	101	88	**521**	437	19
Development	**294**	-	100	**244**	-	100
Corporate	**2,248**	498	351	**5,371**	3,071	75
Capital expenditures	**10,404**	5,800	79	**23,359**	25,697	(9)
Reclamation and abandonment	**5,765**	559	NM	**7,431**	5,549	34
Total capital expenditures	**16,169**	6,359	154	**30,790**	31,246	(1)

Cavvy's focus during the current and prior year was on field and facility optimization and capital preservation.

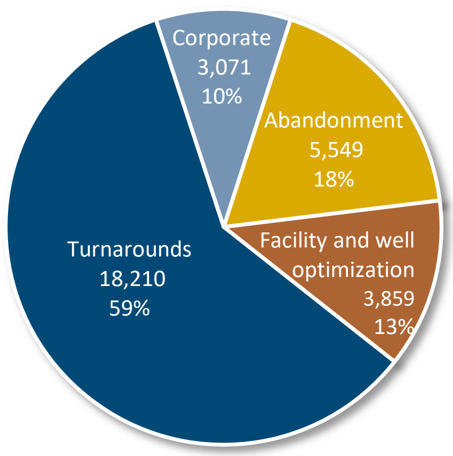
Notably, in 2024 following completion of the rights offering, Cavvy allocated $15.3 million to high impact, quick payout field and facility optimization projects, of which $10.8 million has been incurred to date. This investment generated an aggregate 147% return on investment in 2025. The following table outlines the Company's spend on Rights Offering Projects for years ended December 31, 2025 and 2024:

	Year ended December 31	
($ 000s)	**2025**	**2024**
Facilities and well optimization	**8,698**	1,430
Development	**244**	-
Capital expenditures	**8,942**	1,430
Expense projects	**431**	-
Total Rights Offering capital expenditures	**9,373**	1,430

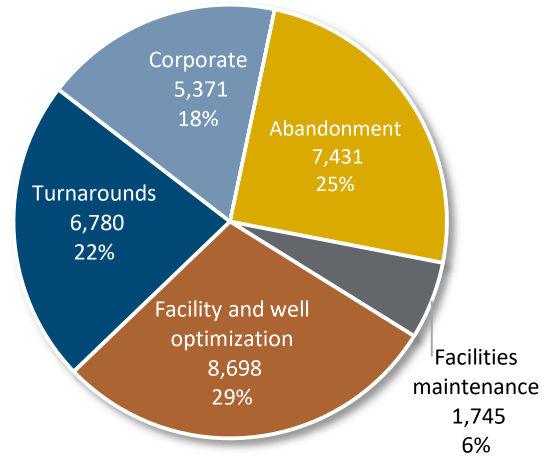
Notable additional capital spending during 2025 included:

- Turnarounds – Capital was expended during the fourth quarter at the Waterton Facility for a major equipment replacement project, during the third quarter at a non-operated facility in northern Alberta in which Cavvy owns a small non-operating working interest, and during the first quarter at the Jumping Pound Facility for repairs to a sulphur condenser
- Corporate – Comprised primarily of information and operational technology modernization investments, and capitalized G&A.
- Reclamation and Abandonment – Cavvy's reclamation and abandonment expenditures were allocated 34% to Alberta liability reduction and 66% to BC.

Capital Expenditures by Classification
Year Ended December 31, 2024



Capital Expenditures by Classification
Year Ended December 31, 2025



LIQUIDITY AND CAPITAL RESOURCES

Capital Resources

As at December 31, 2025, Cavvy's capital structure was comprised of adjusted working capital (deficit), long-term debt and share capital.

The following table summarizes the capital structure at December 31, 2025, and December 31, 2024:

($ 000s)	**December 31, 2025**	**December 31, 2024**
Adjusted working capital (deficit) (1)	**(19,769)**	(29,777)
Current portion of long-term debt	**(9,704)**	(9,885)
Long-term debt	**(141,144)**	(157,902)
Net debt (1)	**(170,617)**	(197,564)
Shareholders' equity	**138,547**	168,428

(1) Refer to "Non-GAAP and Other Financial Measures" section of this MD&A for the definition of adjusted working capital (deficit) and net debt.

Working Capital

The following table summarizes the Company's working capital position at December 31, 2025, and December 31, 2024:

($ 000s)	**December 31, 2025**	**December 31, 2024**
Cash and cash equivalents	**5,799**	8,576
Accounts receivable	**45,830**	50,166
Prepaids expenses and other	**6,122**	7,311
Total current assets	**57,751**	66,053
Accounts payable	**31,068**	32,997
Accrued liabilities	**46,452**	62,833
Total current liabilities	**77,520**	95,830
Adjusted working capital (deficit) (1)	**(19,769)**	(29,777)

(2) Refer to "Non-GAAP and Other Financial Measures" section of this MD&A for the definition of adjusted working capital (deficit).

Cavvy manages to a modest sustainable working capital deficit due to timing differences between cash inflows and outflows. Adjusted working capital (deficit) at December 31, 2025 decreased compared to December 31, 2024, primarily driven by lower accrued liabilities partially offset by lower accounts receivable. Management monitors working capital on a continuous basis with a focus on strengthening the balance sheet through sustaining production, and rigorous cost control across operations and administration.

Long-Term Debt

The table below summarizes long-term debt obligations as of December 31, 2025, and December 31, 2024:

($ 000s)	Maturity		December 31, 2025	December 31, 2024
Senior Facility				
Revolving Loan $22,000	March 2027	USD	**18,100**	15,000
Term Notes $81,500	March 2027	USD	**64,150**	78,230
Subordinated Notes $33,606 (1)	September 2027	USD	**33,606**	32,509
Total debt (2)		USD	**115,856**	125,739
USD/CAD exchange rate (3)			**1.3706**	1.4394
Total principal outstanding		CAD	**158,792**	180,989

(1) Excludes unamortized deferred financing fees of USD $3.2 million (December 31, 2024 – USD $4.6 million), which includes warrants issued in concurrence with the debt refinancing. Includes interest payable in-kind of USD $2.1 million.
(2) As at December 31, 2025, and as at the date of this MD&A, the Company was in compliance with all debt covenants.
(3) USD to CAD exchange rate at December 31, 2025 and 2024, respectively.

Guarantee Facility from Export Development Canada

Cavvy holds a $12.0 million unsecured guarantee facility with Export Development Canada ("EDC"). In July 2025 a portion of this facility previously allocated to a foreign exchange facility was repurposed back to the trade and commercial facility. This facility provides for 100% guarantee to the issuing bank of the Company's existing and future letters of credit of which $10.0 million was drawn at December 31, 2025.

Liquidity

The Company's principal sources of liquidity are cash, the undrawn balance of the Revolving Loan, available capacity on the EDC guarantee facility, and any future debt and equity offerings. The table below summarizes available liquidity as of December 31, 2025and 2024:

($ 000s)	December 31, 2025	December 31, 2024
Cash and cash equivalents	**5,799**	8,576
Undrawn Revolving Loan (1)	**5,345**	10,072
Undrawn EDC guarantee facility	**2,000**	3,603
Total available liquidity (2)	**13,144**	22,251

(1) Converted to CAD using the December 31, 2025 month end exchange rate.
(2) Refer to "Non-GAAP and Other Financial Measures" section of this MD&A for the definition of liquidity.

SHARE CAPITAL, WARRANTS AND STOCK OPTIONS OUTSTANDING

The following table outlines the Company's share capital, stock options and warrants outstanding at March 18, 2026, December 31, 2025, and 2024:

	March 18, 2026	December 31, 2025	December 31, 2024
Share capital	**296,005,505**	**290,680,270**	290,387,642
Stock options	**6,081,209**	**6,286,209**	6,948,475
Stock options – weighted average exercise price ($/option)	**0.48**	**$0.48**	$0.49
Warrants (1)	**19,804,414**	**24,804,414**	24,804,414
Warrants – weighted average exercise price ($/warrant)	**0.45**	**$0.50**	$0.50

(1) Warrants may be accounted for as a liability or as equity depending on their specific terms and conditions. As of December 31, 2025, 5,000,000 outstanding warrants are accounted for as equity and 19,804,414 are accounted for as a liability.

Subsequent to December 31, 2025, 5,000,000 warrants, classified in equity in the Consolidated Financial Statements, were exercised resulting in the issuance of 5,120,235 common shares and proceeds of $3.5 million.

COMMITMENTS, PROVISIONS AND CONTINGENCIES

The Company has entered into several financial obligations during the normal course of business. As at December 31, 2025, these obligations and the expected timing of their settlement, are detailed below:

($ 000s)	2026	2027	2028	Thereafter	Total
Firm transportation	13,315	5,298	38	-	18,651

Provisions and Contingencies

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain, Management believes that any liabilities that may arise from such matters are not likely to have a material effect on the Interim Financial Statements.

Off Balance Sheet Transactions

Cavvy does not have any financial arrangements that are excluded from the Consolidated Financial Statements, nor are any such arrangements outstanding as of the date at this MD&A.

NON-GAAP AND OTHER FINANCIAL MEASURES

Non-GAAP and other financial measures are defined as follows:

Adjusted operating expense

Adjusted operating expense is calculated by netting third-party processing and sulphur revenue from operating expense. This more closely aligns Cavvy's operating expense to peer comparables.

Adjusted working capital or deficit

Adjusted working capital or deficit is calculated as cash, accounts receivable, and prepaid expenses and other, less accounts payable and accrued liabilities. Management considers adjusted working capital or deficit an important measure to evaluate operational liquidity.

Funds flow from operations ("FFO")

FFO equals cash provided by operating activities, less settlement of decommissioning obligations and changes in non-cash working capital. Management considers FFO an important measure to evaluate operational performance as it demonstrates ability to generate cash from operations.

Liquidity

Total available liquidity equals cash and cash equivalents plus the undrawn portions of the delayed draw term loan, the undrawn portion of the Revolving Loan and available capacity on the EDC guarantee facility. Management considers total available liquidity an important measure to evaluate Cavvy's cash available to meet financial obligations.

Net debt

Net debt is calculated as adjusted working capital or deficit less the current and long-term portions of debt. Management considers net debt an important measure as it demonstrates the ability to pay off debt and take on new debt, if necessary.

Net operating income ("NOI")

NOI equals revenue including realized gains (losses) on Financial Contracts, less royalties, operating expenses, and transportation expenses. Management considers NOI an important measure as it reflects the profitability of the Company's core operations before the impact of capital structure and other non-operating items.

Operating netback

Operating netback equals NOI on a per BOE basis. Management considers operating netback an important measure as it provides a comparable metric to evaluate operating performance and profitability on a per-unit basis.

DEFINITIONS AND ABBREVIATIONS

Mcf	Thousand cubic feet	**MWh**	Megawatt hour
Mcf/d	Thousand cubic feet per day	**NGLs**	Natural gas liquids
MMcf	Million cubic feet	**C2**	Ethane
MMcf/d	Million cubic feet per day	**C3**	Propane
Bcf	Billion cubic feet	**C4**	Butane
MMBtu	Million British thermal units	**C5/C5+**	Condensate or pentane
GJ	Gigajoules	**AECO**	Alberta benchmark price for natural gas
GJ/d	Gigajoules per day	**WTI**	West Texas Intermediate benchmark for crude oil
Bbl	Barrel	**AB**	Alberta
Boe	Barrel of oil equivalent	**BC**	British Columbia
Boe/d	Barrel of oil equivalent per day	**US**	United States
mt	Metric tonne	**USD**	United States Dollars
mt/d	Metric tonne per day	**FOB**	Free on Board
MW	Megawatt		
NM	Not meaningful is used to indicate that the current and prior year figures are not comparable or not meaningful.		

RISK FACTORS

The Company complies with current government regulations that affect its activities, although operations may be adversely affected by changes in government policy, regulations, or taxation. In addition, Cavvy maintains a level of liability, and property and business interruption insurance, which is believed adequate for its size and activities, but it is unable to obtain insurance to cover all risks within the business or in amounts to cover all possible claims. Risk to the business and operations include, but are not limited to:

Operational Risks
Adverse Economic Conditions
Operational Matters and Hazards
Development and Production
Co-Ownership of Assets
Reliance on Other Assets, Facilities and Third-Party Services
Facilities Throughput and Utilization
Health and Safety
Regulatory Permits, Licenses and Approvals
Information Technology Systems, Cyber-Security and Technological Change
Skilled Workforce
Labour Relations
Political Uncertainty and Geo-Political Risk
Project Execution
Climate Change
Carbon Pricing
Environmental Regulations
Reputation
Competition
Conflicts of Interest
Indigenous Land Rights Claims
Breach of Confidentiality
Financial Risks
Prices, Volatility and Marketing of Production
Capital Market Access and Liquidity
Cost Management
Hedging Activities
Decommissioning, Abandonment and Reclamation Costs
Reserve Estimates
Variations in Foreign Exchange and Interest Rates
Royalty Regimes

Third-Party Credit Risk
Litigation
Common Share Market Price and Volatility
Insurance Coverage
Dilution
Common Share Liquidity
Internal Controls

Refer to the Company's AIF for the year ended December 31, 2025, for fulsome discussion of these risks. See also "Cautionary Note Regarding Forward-Looking Information" in this MDA.

SIGNIFICANT ACCOUNTING JUDGEMENTS AND ESTIMATES

The timely preparation of the Consolidated Financial Statements requires management to make judgments, estimates and assumptions. These estimates and judgements are subject to change and 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 period in which the estimates are revised and in any future periods affected.

The key sources of estimation uncertainty that have a significant risk of causing material adjustment to the carrying amounts of assets, liabilities, revenues and expenses are discussed below:

a. Identification of cash-generating units

Some of the Company's assets are aggregated into CGUs for the purpose of calculating depletion and impairment. A CGU is comprised of assets that are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. By their nature, these estimates and assumptions are subject to measurement uncertainty and may impact the carrying value of the Company's assets in future periods.

b. Impairment of petroleum and natural gas assets

For the purposes of determining whether impairment of petroleum and natural gas assets has occurred and the extent of any impairment or its reversal, the key assumptions the Company uses in estimating future cash flows are forecasted petroleum and natural gas prices, expected production volumes and anticipated recoverable quantities of proved and probable reserves. These assumptions are subject to change as new information becomes available. Changes in economic conditions can also affect the rate used to discount future cash flow estimates. Changes in the aforementioned assumptions could affect the carrying amounts of assets. Impairment charges and reversals are recognized in statements of income. The rates used to discount future cash flows are based on judgment of economic, regulatory and operating factors. Changes in these factors could increase or decrease the discount rate which may result in material changes.

c. Debt instruments

Debt instruments are initially recognized at fair value based on consideration received and adjusted in respect of any transaction costs that are incremental and directly attributable to the issue of the instrument. Subsequent measurement is at amortized cost and the effective interest rate method. Certain financing arrangements contain options which may revise future estimated cash outflow and result in an adjustment to the carrying value of the financial liability. At each reporting period, the Company will estimate whether such options will be exercised and if an adjustment to the financial liability is required. All adjustments arising from such changes in estimates are recognized immediately in profit or loss.

d. Reserves

The assessment of reported recoverable quantities of proved and probable reserves include estimates regarding production profile, commodity prices, carbon compliance costs, potential tariff changes, exchange rates, remediation costs, timing and amount of future development costs and production, transportation and marketing costs for future cash flows. It also requires interpretation of geological, engineering and geophysical models in anticipated recoveries. The economical, geological and technical factors used to estimate reserves may change from period to period. Changes in reported reserves can impact the carrying values of the Company's PP&E, the calculation of depletion, the provision for decommissioning obligations and the recognition of deferred tax assets due to changes in expected future cash flows. The recoverable quantities of proved and probable reserves and associated estimated cash flows are independently evaluated by qualified reserve evaluators at least annually.

The Company's petroleum and natural gas reserves represent the estimated quantities of petroleum and natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered economically producible. Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon (i) a reasonable assessment of the future economics of such production; (ii) a reasonable expectation that there is a market for all or substantially all the expected petroleum and natural gas production; and (iii) evidence that the necessary production, transmission and transportation facilities are available or can be made available. Reserves may only be considered proven and probable if the ability to produce is supported by either production or conclusive formation tests. The Company's petroleum and gas reserves are determined pursuant to National Instrument 51-101, Standard for Disclosures for Oil and Gas Activities.

e. Decommissioning obligations

The Company estimates future decommissioning and remediation costs of production facilities, processing facilities, wells and pipelines at the end of their economic lives based on current legislation and operating practices. In most instances, abandonment and reclamation of these assets occurs many years into the future. In estimating future decommissioning obligations, the Company makes assumptions concerning:

- The nature and scope of work required to abandon and reclaim properties and the costs thereof, which incorporate the Company's prior experience in abandoning properties with similar characteristics, any site-specific liability assessments and other available benchmarks
- The dates that abandonment and reclamation work will be performed in the future, which incorporates expectations of the productive lives of properties and the requirements of applicable laws: and
- The inflation and risk-free discount rate.

The actual amount and timing of payments to settle decommissioning obligations may materially differ from estimates due to, among other things, changes in laws and regulations, changes in technology and operating practices and changes in life of proven and probable reserves. These differences may have a material impact on the decommissioning obligation provision in the future.

f. Deferred Taxes

Tax provisions are based on enacted or substantively enacted laws. Changes in those laws could affect amounts recognized in statements of income in the period of change, which would include any impact on cumulative provisions and in future periods. Judgments are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings. To the extent that assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amount recognized in statements of income for the period in which the change occurs.

CONTROL ENVIRONMENT

Disclosure Controls and Procedures

As of December 31, 2025, an internal evaluation was carried out of the effectiveness of the Company's disclosure controls and procedures as defined in Canada by National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109"). Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Company files or submits under Canadian Securities Legislation is recorded, processed, summarized, and reported, within the time periods specified in the rules and forms therein. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that the information required to be disclosed by the Company in the reports that it files or submits under Canadian Securities Legislation is accumulated and communicated to Cavvy's Management as appropriate to allow timely decisions regarding the required disclosure.

It should be noted that while the Company's disclosure controls and procedures are intended to provide a reasonable level of assurance that information required to be disclosed is recorded, processed, summarized and reported within the time periods specified in securities legislation, disclosure controls and procedures cannot be expected to prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met

Internal Controls over Financial Reporting

Internal controls over financial reporting ("ICFR") is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable, and timely 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 Organizations of the Treadway Commission. Management concluded that the Company's ICFR was effective as of December 31, 2025. No changes were made to the Company's internal control over financial reporting during the year ended December 31, 2025, that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statements preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may deteriorate.

NEW ACCOUNTING POLICIES

Disclosures about Uncertainty in Financial Statements

On November 27, 2025, the International Accounting Standards Board ("IASB") published final illustrative examples to support disclosures about uncertainty in financial statements. These examples were developed in response to stakeholder concerns regarding the reporting of the effects of climate-related risks and were broadened by the IASB to address uncertainties more generally.

The illustrative examples are intended to assist entities in the consistent application of existing IFRS Accounting Standards and to enhance the quality, clarity, and usefulness of disclosures about the effects of uncertainties, including those arising from significant judgements and estimation uncertainty. The examples do not introduce new recognition or measurement requirements but provide guidance on how existing disclosure requirements may be applied in circumstances where uncertainty could reasonably influence users' understanding of the financial statements. Management has considered and applied these amendments, where necessary, in the Consolidated Financial Statements.

FUTURE ACCOUNTING PRONOUNCEMENTS

IFRS 18 Presentation and Disclosure in Financial Statements

In April 2024, the IASB issued IFRS 18 – Presentation and Disclosure in Financial Statements, which replaces IAS 1 – Presentation of Financial Statements and establishes a revised structure for the financial statements, required disclosures for certain management-defined performance measures and enhanced requirements for grouping of information in the financial statements. IFRS 18 is effective for years beginning on or after January 1, 2027, with early adoption permitted. The Company is currently in the process of assessing its impact on its Consolidated Financial Statements.

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

In May 2024, the IASB issued Amendments to the Classification and Measurement of Financial Instruments (Amendments to IFRS 7 and IFRS 9). The amendments issued to IFRS 7 and IFRS 9 clarify the date of recognition and detection of some financial assets and liabilities, with new exceptions for some liabilities settled through electronic cash transfer. The amendments also clarify and add further guidance for assessment of whether a financial asset meets the "solely payments of principal and interest criteria", as well as adds new disclosures for certain instruments with contractual terms that can change cash flows. Finally, this amendment also updates the disclosures for equity instruments designated at fair value through other comprehensive income. These amendments take effect on or after January 1, 2026, with early adoption permitted. These amendments will not have a material impact on the Consolidated Financial Statements.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING INFORMATION

Certain of the statements contained in this MD&A constitute forward-looking information relating to, without limitation, management expectations, intentions and assessments of future plans, strategies and operations, the Company's expected capital budget, the Company's future business plan and strategy, the Company's criteria for evaluating acquisitions and other opportunities, intentions with respect to future acquisitions and other opportunities, plans and timing for development of undeveloped and probable resources, timing of when the Company may be taxable, estimated abandonment and reclamation costs, plans regarding hedging, wells to be drilled, the weighting of commodity expenses, expected production and performance of oil and natural gas properties, results and timing of projects, access to adequate pipeline capacity and third-party infrastructure, growth expectations, supply and demand for oil, NGLs, and natural gas, industry conditions, government regulations and regimes, and capital expenditures and the nature of capital expenditures and the timing and method of financing thereof, may constitute "forward-looking statements" or "forward-looking information" within the meaning of Applicable Securities Laws (as defined herein) (collectively "forward-looking statements"). Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "focus", "plan", "ensure", "grow", "sustain", "potential", "continue", "estimate", "expect", "project", "forecast", "target", "future", and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs, estimates and opinions regarding the Company's future growth, results of operations, performance and plans and timing for development of business prospects and opportunities and are based on information currently available to management.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the earlier of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products, and volatility of and assumptions regarding crude oil, natural gas, and NGL prices.

Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to: general economic and business conditions, tariffs or other trade restrictions imposed on Canada by the United States, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices and interest rates, currency fluctuations, imprecision of resources estimates, environmental risks, competition from other producers, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, expectations on leveraging ability to increase third-party utilization and associated revenues, delays resulting from or inability to obtain required regulatory approvals, ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and resource estimates of the Company's reserves provided herein are estimates only and there is no guarantee that the estimated resources will be recovered. Consequently, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements are based on a number of factors and assumptions which have been used to develop such forward-looking statements, but which may prove to be incorrect. Although the Company believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because the Company can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which the Company operates; the timely receipt of any required regulatory approvals; the Company's ability to obtain qualified staff, equipment and services in a timely and cost efficient manner; the feasibility of and effectiveness of management's mitigation plans; the expectations that the current claims and litigation of the Company will not materially affect the Company's Interim Financial Statements, the ability of the operator of the projects which the Company has an interest in to operate the field in a safe, efficient and effective manner; the Company's ability to obtain financing on acceptable terms; the ability to replace and expand oil and natural gas resources through acquisition, development and exploration; the timing and costs of pipeline, storage and facility construction and expansion and the Company's ability to secure adequate product transportation; expectations on future oil and natural gas prices and anticipated production volumes and recoverable quantities; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Cavvy operates; timing and amount of capital expenditures, future sources of funding, production levels, weather conditions, success of exploration and development activities, access to gathering, processing and pipeline systems, advancing technologies, and the Company's ability to successfully market oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Cavvy's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedarplus.com), and on Cavvy's website (www.cavvyenergy.com). Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Company assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements contained herein concerning the oil and gas industry and the Company's general expectations concerning this industry are based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research, industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on numerous factors.