2025 ANNUAL RESULTS

TO SHAREHOLDERS

2025 was a year of strong execution that validated our strategy and reinforced Rubellite's potential. We delivered meaningful financial progress, marked by free funds flow generation, and consistent operational performance, while advancing key value-creation initiatives across our asset base. We enter 2026 with positive momentum, a deep inventory of opportunities and a disciplined plan to build on that progress.

Rubellite Energy's strategy is to build a highly profitable heavy-oil business centered on the application of multi-lateral drilling technology and enhanced oil recovery to economically develop resources in the Clearwater and Mannville Stack, and other attractive zones within the Western Canadian Sedimentary Basin. We seek to create long-term shareholder value by identifying large-scale resource fairways well suited to these techniques, capturing prospects at a low cost, and advancing them through disciplined evaluation, appraisal, and development. By minimizing risked capital and applying technical rigor and operational excellence, we aim to unlock sizable assets capable of generating durable free funds flow. Our capital structure objectives remain clear: ensure liquidity to fund operations and capital programs in the context of underlying commodity price cycles and volatility, and preserve financial flexibility to pursue strategic opportunities to maximize long-term shareholder value.

Our strategy translated into tangible results in 2025. We delivered significant year-over-year growth in production and adjusted funds flow per share, reflecting the scalability and repeatability of our core heavy oil assets. Our operations generated meaningful free funds flow, providing the flexibility to reinvest in high-return development, advance enhanced oil recovery pilot initiatives, strengthen the balance sheet, and continue capturing opportunities for long-term value. Importantly, this growth was underpinned by ongoing gains in operating cost efficiency and disciplined capital allocation, leading to a 7% reduction in net debt.

Operationally, our core heavy oil assets continued to perform well. Capital was directed to our highest-return development opportunities at Figure Lake, as well as to unlocking new zones at both Figure Lake and Frog Lake, and to accelerating the evaluation of the secondary recovery potential at Figure Lake. Encouraging early performance from the Sparky test at Figure Lake, together with promising results and ongoing well design optimization in the General Petroleum zone at Frog Lake, supported a 30% increase to our booked(1) plus internally-recognized inventory of 396 high confidence development locations. Enhanced oil recovery remains a central value lever for Rubellite, and during the year we advanced multiple pilots scheduled for implementation in 2026 and designed to increase heavy oil recovery factors. If successfully implemented at scale, waterflood will reduce base declines, lower maintenance capital, extend asset life, and increase free funds flow from our core heavy oil assets.

At year-end 2025, Rubellite's reserve-based net asset value(1) is estimated at $5.95 per share. In addition to the ongoing efficient development of our total proved plus probable reserves(1), focus also lies on converting our deep inventory of over 240 net unbooked development locations that are not yet captured in the independent reserve assessment into production, reserves, adjusted funds flow and value through primary development, while at the same time advancing secondary recovery pilots and de-risking our pipeline of exploration opportunities.

To this end, our strategic priorities for 2026 outlined below reflect our conviction that excellence in execution, disciplined capital allocation and active risk management are critical to compounding value through cycles.

1. Optimize value and free funds flow generation from base assets;
2. Improve capital efficiencies;
3. Accelerate advancement of enhanced oil recovery in core assets;
4. De-risk exploration prospects and grow potential asset value;
5. High-grade land portfolio and expand prospect inventory for chosen play strategies;
6. Establish pristine balance sheet and manage risk; and
7. Drive operational excellence and capture cost efficiencies.

Rubellite's progress is underpinned by the strength of our people and our culture. With 2026 underway, we are focused on disciplined execution across all elements of our strategy that creates lasting value for our shareholders as well as for the broader communities connected to our business. Thank you for your continued confidence and support.

Susan Riddell Rose

SUE RIDDELL ROSE
President and Chief Executive Officer

March 10, 2026

(1) See *"Year-End 2025 Reserves"* and "*Net Asset Value*" on pages 6 to 10 in this Annual Results report.

SUMMARY OF ANNUAL RESULTS

($ thousands, except as noted)	2025	2024	2023	2022
Financial				
Oil and natural gas revenue	**241,700**	168,384	88,968	54,491
Net income and comprehensive income	**32,557**	49,973	18,561	24,605
Per share – basic(1)	**0.35**	0.73	0.31	0.47
Per share – diluted(1)	**0.34**	0.72	0.30	0.47
Total Assets	**578,509**	562,612	271,153	204,030
Cash flow from operating activities	**128,796**	95,788	55,391	23,870
Adjusted funds flow, including transaction costs(2)(6)	**142,073**	93,777	54,154	23,036
Per share – basic(1)(2)	**1.52**	1.37	0.90	0.44
Per share – diluted(1)(2)	**1.48**	1.35	0.89	0.44
Adjusted funds flow, before transaction costs(2)(6)	**142,073**	100,010	54,304	23,036
Per share – basic(1)(2)	**1.52**	1.46	0.90	0.44
Per share – diluted(1)(2)	**1.48**	1.43	0.89	0.44
Q4 annualized adjusted funds flow(2)(10)	**132,660**	143,420	68,280	32,580
Net debt to Q4 annualized adjusted funds flow ratio(2)(10)	**1.1**	1.1	0.7	0.9
Net debt(2)	**143,143**	154,020	50,984	28,228
Capital expenditures(2)				
Total capital expenditures(2)	**130,502**	108,906	71,530	94,207
Acquisitions(7)(8)	**—**	179,247	33,173	—
Dispositions(9)(11)	**—**	—	(7,990)	—
Total capital expenditures, after acquisitions and dispositions	**130,502**	288,153	96,713	94,207
Wells Drilled(3) – gross (net)	**53 / 43.8**	46 / 41.5	30 / 29.5	45 / 39.5
Common shares outstanding(1) *(thousands)*				
Weighted average – basic	**93,283**	68,667	60,346	52,093
Weighted average – diluted	**96,036**	69,716	61,075	52,471
End of period	**93,593**	93,044	62,456	54,826
Sales Production				
Heavy oil (bbl/d)(4)	**8,402**	5,685	3,302	1,670
Natural gas (MMcf/d)	**22.4**	3.6	—	—
NGL (bbl/d)(5)	**365**	69	—	—
Daily average sales production (boe/d)	**12,494**	6,349	3,302	1,670
Reference prices				
West Texas Intermediate ("WTI") ($US/bbl)	**64.81**	75.72	77.62	94.22
Western Canadian Select ("WCS") ($CAD/bbl)	**75.14**	83.52	79.46	98.49
AECO 5A Daily Index ($CAD/Mcf)	**1.71**	1.46	2.64	5.34
Rubellite average realized prices(2)(7)				
Oil ($/bbl)	**71.38**	78.92	73.82	89.38
Natural gas ($/Mcf)	**1.84**	2.01	—	—
NGL ($/bbl)	**58.18**	61.32	—	—
Total average realized price(2) ($/boe)	**53.00**	72.46	73.82	89.38
Average realized price, after risk management contracts(2) ($/boe)	**55.49**	73.57	73.56	67.82
Operating netback ($/boe)				
Revenue	**53.00**	72.46	73.82	89.38
Royalties	**(7.12)**	(8.72)	(7.06)	(9.37)
Net operating costs(2)	**(6.48)**	(7.11)	(6.12)	(7.22)
Transportation costs	**(5.18)**	(7.03)	(7.50)	(7.30)
Operating netback(2)	**34.22**	49.60	53.14	65.49
Realized gain (loss) on risk management contracts	**2.49**	1.11	(0.26)	(21.56)
Total operating netback, after risk management contracts(2)	**36.71**	50.71	52.88	43.93

(1) Per share amounts are calculated using the weighted average number of basic or diluted common shares.
(2) Non-GAAP measure or ratio. See "Non-GAAP and Other Financial and Reserves Measures" contained in this Annual Results report.
(3) Well count reflects wells rig released during the period.
(4) Heavy oil sales production excludes tank inventory volumes.
(5) Liquids means oil, condensate, ethane and butane.
(6) Transaction costs of $6.2 million in 2024 (BMEC Acquisition and Recombination Transaction), and $0.1 million in 2023 (Clearwater Acquisition).
(7) The Recombination Transaction closed on October 31, 2024 for share consideration of $51.7 million. The BMEC Acquisition closed on August 2, 2024 for total consideration of $73.1 million.
(8) Clearwater Acquisition closing on November 8, 2023 for cash consideration of $34.0 million, prior to purchase price adjustments.
(9) Royalty sale closed on December 8, 2023 for cash consideration of $8.0 million, prior to purchase price adjustments.
(10) Based on fourth quarter annualized adjusted funds flow before transaction costs relative to year-end net debt.

(11) In 2025, the Company disposed of non-producing acreage for cash consideration of $7.8 million with a net book value of nil, resulting in a gain on disposition of assets of $7.8 million reported in the Company's statement of income and other comprehensive income.

ADVISORIES

This letter to shareholders, 2025 annual highlights and Annual Results report refer to certain non-GAAP measures and metrics commonly used in the oil and natural gas industry and provides forward-looking information and statements. Further detailed information regarding these measures is provided in this Annual Results report in "Management's Discussion and Analysis – NON-GAAP AND OTHER FINANCIAL MEASURES" on pages 28 to 31, "Management's Discussion and Analysis – FORWARD-LOOKING INFORMATION" on pages 33 and 34.

In addition to the disclosure set out in the Company's Management's Discussion and Analysis for the period ended December 31, 2025 we provide certain supplementary disclosure throughout this Annual Results report in respect of certain specified financial measures (as such term is defined in National Instrument 51-112 – *Non-GAAP and Other Financial Measures*) and in respect of certain oil and gas metrics.

2025 FOURTH QUARTER AND ANNUAL FINANCIAL AND OPERATING HIGHLIGHTS

Sales Production Volumes

- **Heavy oil:** Averaged 8,295 bbl/d in the fourth quarter of 2025, up 7% from 7,754 bbl/d in the fourth quarter of 2024. Achieved record annual heavy oil sales production of 8,402 bbl/d, up 48% from 5,685 bbl/d in 2024 and above guidance of 8,325 to 8,400 bbl/d.

- **Total sales production:** Delivered record fourth quarter average sales production of 13,042 boe/d (67% heavy oil and natural gas liquids ("NGL")), up 26% from 10,386 boe/d (77% heavy oil and NGL) in the fourth quarter of 2024, and record annual sales production of 12,494 boe/d (70% heavy oil and NGL), up 97% from 6,349 boe/d (91% heavy oil and NGL) in 2024 and exceeding guidance of 12,325 to 12,400 boe/d.

- **Heavy oil new wells:** Brought 14 (12.5 net) heavy oil wells onstream at Figure Lake and Frog Lake in the fourth quarter, for a total of 46 (39.0 net) new heavy oil wells contributing to sales in 2025.

- **West Central natural gas new wells:** Added 2 (1.0 net) liquids-rich conventional natural gas wells to production at East Edson at the end of the third quarter and 2 (1.0 net) additional wells late in the fourth quarter of 2025.

- **Figure Lake gas plant:** With the initial facility start up in January and subsequent expansion in the second half of 2025, natural gas sales averaged 5.6 MMcf/d in the fourth quarter and 3.4 MMcf/d in 2025.

Capital Expenditures

- **Exploration and development spending[(1)]:** Spent $34.8 million in the fourth quarter and $114.6 million for 2025, at the high end of the guided range of $110.0 to $115.0 million. Fourth quarter spending included the drilling, completion, equipping and tie-in of 6 (6.0 net) multi-lateral horizontal Clearwater development wells and 1 (1.0 net) multi-lateral horizontal Sparky well at Figure Lake; 4 (3.0 net) multi-lateral horizontal Waseca development wells and 3 (2.5 net) single leg horizontal wells in new zones at Frog Lake; and 2 (1.0 net) liquids-rich conventional natural gas wells at East Edson, bringing total 2025 drilling activity to 53 (43.8 net) wells.

- **Figure Lake gas plant:** Spent $0.7 million in the fourth quarter and $4.1 million in 2025 to finish initial construction and expand the gas plant and gas gathering system at Figure Lake, bringing processing capacity to 6.4 MMcf/d by the fourth quarter of 2025.

- **Land:** Spent $0.3 million in the fourth quarter, bringing total land costs to $10.5 million in 2025. In the fourth quarter, the Company sold 7 sections of undeveloped land, subject to a retained gross overriding royalty, for $2.3 million, bringing total proceeds from the disposition of non-producing acreage in 2025 to $7.8 million, which funded other capital activities.

- **Geological and geophysical costs:** Spent $3.8 million in the fourth quarter and $4.9 million in 2025 to shoot new 3D seismic and acquire trade data to support the development of the Clearwater and other Mannville Stack prospects, including the evaluation of new zones.

- **Abandonment and Reclamation:** Spent $0.6 million in the fourth quarter and $1.9 million in 2025 on decommissioning, abandonment and reclamation activities and received seven reclamation certificates from the Alberta Energy Regulator ("AER") (2024 - one), with two additional reclamation certificates received subsequent to year-end.

Financial Performance

- **Adjusted funds flow[(1)]:**
    - $33.2 million ($0.35 per share) in the fourth quarter of 2025, up 5% from $31.6 million ($0.36 per share) in the fourth quarter of 2024.
    - $142.1 million ($1.52 per share) in 2025, up 52% (12% per share) from 2024 driven by a 97% increase in sales volumes and 20% lower cash costs, partially offset by a 10% decrease in average realized prices.

- **Cash costs[(1)]:**
    - $18.5 million or $15.41/boe in the fourth quarter of 2025, 21% lower on a per boe basis than the fourth quarter of 2024 (Q4 2024 - $18.6 million or $19.45/boe).
    - $78.6 million or $17.24/boe in 2025, 20% lower on a per boe basis than 2024 (2024 - $50.4 million or $21.68/boe).

- **Net income:**
    - $9.7 million ($0.10 per share) in fourth quarter of 2025 (Q4 2024 - $26.7 million net income or $0.31 per share).
    - $32.6 million ($0.35 per share) in 2025 (2024 - $50.0 million or $0.73 per share).

Balance Sheet and Liquidity

- **Net debt[(1)]:** $143.1 million at December 31, 2025, down 7% from $154.0 million at December 31, 2024, driven by $11.6 million of positive free funds flow[(1)] used to reduce net debt and other obligations.

- **Available liquidity[(2)]:** $46.0 million at December 31, 2025, based on a $140.0 million first-lien credit facility borrowing limit, less $92.6 million of bank borrowings and $1.4 million in letters of credit.

(1) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial and Reserves Measures" in this Annual Results report.
(2) See "Liquidity, Capitalization and Financial Resources - Capital Management" in the MD&A.

2025 GUIDANCE RECONCILIATION

During 2025, Rubellite recorded strong growth from a successful drilling program, which saw both heavy oil and total sales production exceed the high end of the 2025 guidance range. A comparison of the Company's most recent 2025 guidance metrics to actual results is provided below.

	2025 Guidance(1)	2025 Actuals
Sales Production (boe/d)	12,325 - 12,400	12,494
Production mix (% liquids)(2)	70%	70%
Heavy oil sales production (bbl/d)	8,325 - 8,400	8,402
Exploration and development spending ($ millions)(3)(4)	$110 - $115	$114.6
Heavy oil wellhead differential ($/bbl)(3)	$3.75 - $4.00	$3.76
Royalties (% of revenue)(3)	13% - 14%	13%
Production and operating costs ($/boe)(3)	$6.50 - $7.00	$6.48
Transportation costs ($/boe)(3)	$5.25 - $5.50	$5.18
General and administrative costs ($/boe)(3)	$3.00 - $3.50	$3.48

(1) 2025 guidance dated November 5, 2025.
(2) Liquids means oil, condensate, ethane, propane and butane.
(3) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial and Reserves Measures".
(4) Excludes abandonment and reclamation spending, land and acquisitions and geological expenditures, if any.

YEAR-END 2025 RESERVES HIGHLIGHTS

As presented in the McDaniel Report[1], Rubellite's total proved plus probable reserves[1] at year-end 2025 were 53.1 MMboe, comprised of 55% heavy crude oil (2024 year-end total proved plus probable reserves were 53.0 MMboe, 51% heavy crude oil). The Company's total proved plus probable reserves grew by 0.1 MMboe (0.1%) year-over-year, resulting in production replacement[4] of 4.6 MMboe by 1 times.

Growth in reserves is attributed to the successful drilling programs at Figure Lake and Frog Lake which combined to add 6.1 MMboe to the year-end proved plus probable reserves balance. This organic growth through the drill bit in the Clearwater, Sparky, Waseca and GP plays accounted for all additions of 6.1 MMboe, and resulted in production replacement[4] from the Company's heavy oil properties of 3.3 MMboe by 1.9 times.

Other highlights from the McDaniel Report[1] include:

- Total proved reserves increased 0.5% (0.2 MMboe) to 32.9 MMboe from 32.7 MMboe and representing 62% of the Company's proved plus probable reserves (2024 – 62%).

- Proved developed producing reserves were 18.1 MMboe, an increase of 2% and representing 34% of the Company's proved plus probable reserves (2024 year-end proved developed producing reserves were 17.7 MMboe; 33% of total proved plus probable reserves).

- Proved plus probable developed producing reserves were 23.3 MMboe, representing 44% of total proved plus probable reserves (2024 year-end proved plus probable developed producing 23.0 MMboe; 43% of proved plus probable reserves).

- Rubellite's total capital expenditures[4] of $130.0 million (which excludes $0.5 million of corporate capital) resulted in total proved plus probable additions of 4.6 MMboe and included a change in future development capital of $21.2 million. The reserve additions resulted in finding and development ("F&D") costs[4] of $32.73/boe. Higher than normal cost of reserve additions were observed this year due to a negative technical revision in the Edson Joint Venture property, which offset the positive additions in the heavy oil properties. Rubellite had cash proceeds from dispositions of undeveloped land of $7.8 million which had no reserves assigned prior to the disposition.

- At the Eastern Heavy Oil cash generating unit ("CGU") level, exploration and development expenditures[4] totalled $100.5 million, land expenditures of $10.5 million, after adjusting for the $7.8 million of cash proceeds related to the sale of land with no reserves assigned or net book value, geological and geophysical spending was $4.9 million, and the change in future development capital for Rubellite's heavy oil assets was $36.4 million. With heavy oil reserve additions of 6.3 MMboe, the Adjusted Heavy Oil F&D costs per boe[4] on a 2P basis were $22.93/boe with a recycle ratio[4] of 2.0, based on a 2025 heavy oil operating netback[4] of $45.15/boe. For more details see section *"Adjusted F&D Ratios"*.

- The McDaniel Report includes a total of 214 (167.2 net) booked undeveloped drilling locations, which are comprised of 139 (109.2 net) proved undeveloped and 75 (58.0 net) probable undeveloped locations. Of these, 111 (109.7 net) are in the Figure Lake area with 72 (71.1 net) that are proved undeveloped and 39 (38.6 net) probable undeveloped.

- Continued drilling success in 2025 in the Figure Lake property resulted in outperformance, in aggregate, relative to the 2024 type curves. In the McDaniel Report, IP30 rates were increased on Figure Lake Tier 1 and Tier 2 type curves to 201 bbl/d (2024 - 177 bbl/d) and 144 bbl/d (2024 - 120 bbl/d), respectively. In the Edwand sub-area of Figure Lake, which has it's own type curves, IP30 rates were also increased to 191 bbl/d (2024 - 175 bbl/d), as were proved plus probable estimated ultimate recoverable ("EUR") volumes to 125 Mboe per well (2024 - 115 Mboe per well).

- At Frog Lake, success in drilling, and executing well operational strategies to deal with sand production, resulted in both developed producing and undeveloped reserve adds in the GP formation. Four (3.0 net) GP wells were drilled in 2025 with developed producing reserves, with an additional 17 (8.5 net) booked undeveloped locations. Of these undeveloped locations, 7 (3.5 net) are proved undeveloped and 10 (5.0 net) are probable undeveloped. In the McDaniel Report, the GP type curve has an IP30 rate of 73 bbl/d and proved plus probable reserves of 85 Mboe.

- All abandonment, decommissioning and reclamation obligations are included in the McDaniel Report, consistent with year-end 2024. Decommissioning obligations for wells assigned reserves are forecast to occur at end of life while the additional costs expected to be incurred to abandon and reclaim non-reserve wells, facilities and pipelines are forecast in accordance with regulatory asset retirement obligation spending requirements for inactive wells.

- Rubellite's undeveloped land was independently assessed in the Seaton-Jordan Report[3], at $59.6 million, an increase of 22% from $48.8 million.

- Based on the three consultant average price (McDaniel, GLJ Ltd., Sproule Associates Limited) forecasts (the "Consultant Average Price Forecast") used by McDaniel, the net present value ("NPV") of Rubellite's total proved plus probable reserves (discounted at 10%) before income tax, was $651.5 million (2024 – $721.5 million). The 10% NPV10 decrease from year-end 2024 is related directly to the reduction in commodity price forecasts based on the Consultant Average Price Forecast, and to a lesser degree, the negative technical revisions in the Edson Joint Venture property, offset by positive reserve revisions and additions in the Company's heavy oil properties.

- Based on the Consultant Average Price Forecast, Rubellite's reserve-based net asset value ("NAV")[4] (discounted at 10%) at year-end 2025, is estimated at $556.6 million ($5.95 per share) as compared to $601.1 million ($6.47 per share) at year-end 2024. The reserve-based NAV is inclusive of the independent assessment of undeveloped land and net of the Company's total net debt[4] and other obligations[4], which includes $143.1 million of net debt and $16.2 million for the undiscounted amount of the other provision[4].

(1) "McDaniel Report" means the independent engineering evaluation of the Company's heavy crude oil, conventional natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026.
(2) Type curve assumptions are based on the total proved plus probable Undeveloped reserves contained in the McDaniel Report as disclosed in the Company's AIF which will be available under the Company's profile on SEDAR+ at www.sedarplus.ca.
(3) The value of Rubellite's undeveloped land was assessed by an independent third party, Seaton-Jordan & Associates Ltd., as at December 31, 2025 in a report dated January 26, 2026 (the "Seaton-Jordan Report"). Estimates of the value of Rubellite's undeveloped acreage was prepared in accordance with NI 51-101 5.9(1)(e) for purposes of the net asset value calculation and is based on past Crown land sale activity, adjusted for tenure and other considerations. No undeveloped land value is assigned where reserves have already been booked, even if the corresponding lease contains multiple prospective formations that have not yet been assigned reserves .
(4) Non-GAAP financial measure or non-GAAP ratio. See "Non-GAAP and Other Financial and Reserves Measures" in this Annual Results report.

YEAR-END 2025 RESERVES DATA

The following presentation summarizes the Company's crude oil, natural gas liquids and conventional natural gas reserves and the net present values before income tax of future net revenue for the Company's reserves using the forecast prices and costs reflected in the McDaniel Report. The McDaniel Report has been prepared in accordance with definitions, standards, and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). McDaniel prepared the McDaniel Report using their own technical assumptions and interpretations, methodologies and cost assumptions and the equal weighting of the Consultant Average Price Forecast as outlined in the table below entitled "Price Forecast". See "Reserves Data and Industry Metrics" for additional cautionary language, explanations and discussion and "Forward-Looking Information" for principal assumptions and risks that may apply.

Corporate Reserves

	Light & Medium Crude Oil	Natural Gas Liquids	Conventional Natural Gas	Barrels of oil equivalent
	(Mbbl)	(Mbbl)	(MMcf)	(Mboe)
Proved				
Developed Producing	8,485	878	52,212	18,065
Developed Non-producing	48	14	742	185
Undeveloped	9,078	548	29,954	14,619
Total Proved ("1P")(1)	**17,610**	**1,441**	**82,907**	**32,869**
Total Probable	11,608	826	46,596	20,199
Total Proved plus Probable ("2P")(1)	**29,218**	**2,266**	**129,504**	**53,068**

(1) May not add due to rounding.

Reserves Value

The estimated before tax net present value ("NPV") of future net revenues associated with Rubellite's reserves effective December 31, 2025, and based on the McDaniel Report and the Consultant Average Price Forecast, are summarized in the following table:

($ thousands)	**0%**	**5%**	**10%**	**15%**	**20%**
Proved					
Developed Producing	318,180	297,581	268,892	244,180	224,027
Developed Non-producing	3,844	3,233	2,775	2,434	2,171
Undeveloped	231,446	163,672	116,809	83,536	59,265
Total Proved(1)	**553,471**	**464,485**	**388,476**	**330,150**	**285,463**
Total Probable	519,985	360,275	263,019	200,268	157,698
Total Proved plus Probable(1)	**1,073,455**	**824,760**	**651,496**	**530,418**	**443,160**

(1) May not add due to rounding.

Price Forecast

The Consultant Average Price Forecast December 31, 2025 price forecast used for the purposes of preparing the McDaniel Report is summarized as follows:

Year	WTI @ Cushing	WCS @ Hardisty	AECO/NIT spot	Exchange Rate
	(US$/bbl)	(C$/bbl)	(C$/MMbtu)	($US/$CDN)
2026	59.92	65.13	3.00	0.728
2027	65.10	70.43	3.30	0.737
2028	70.28	76.90	3.49	0.740
2029	71.93	78.71	3.58	0.740
2030	73.37	80.29	3.65	0.740
2031	74.84	81.90	3.72	0.740
2032	76.34	83.53	3.80	0.740
2033	77.87	85.20	3.88	0.740
2034	79.42	86.91	3.95	0.740
2035	81.01	88.65	4.03	0.740
2036+	+2%	+2%	+2%	constant

For comparison purposes, the Consultant Average Price Forecast December 31, 2024 price forecast used for the purposes of preparing the 2024 McDaniel Report is summarized below:

Year	WTI @ Cushing	WCS @ Hardisty	AECO/NIT spot	Exchange Rate
	(US$/bbl)	(C$/bbl)	(C$/MMbtu)	($US/$CDN)
2025	71.58	82.69	2.36	0.712
2026	74.48	84.27	3.33	0.728
2027	75.81	83.81	3.48	0.743
2028	77.66	85.70	3.69	0.743
2029	79.22	87.45	3.76	0.743
2030	80.80	89.25	3.83	0.743
2031	82.42	91.04	3.91	0.743
2032	84.06	92.85	3.99	0.743
2033	85.74	94.71	4.07	0.743
2034	87.46	96.61	4.15	0.743
2035+	+2%	+2%	+2%	constant

Reserves Reconciliation

The following reconciliation of Rubellite's gross reserves compares changes in the Company's independently evaluated reserves as at December 31, 2025, relative to the reserves as at December 31, 2024:

	Mboe		
	Total Proved	**Total Probable**	**Total Proved+Probable**
December 31, 2024	32,690	20,318	53,009
Extensions and Improved Recoveries	4,005	2,085	6,089
Discoveries	—	—	—
Technical Revisions	984	(2,138)	(1,154)
Acquisitions	—	—	—
Dispositions	—	—	—
Production	(4,560)	—	(4,560)
Economic Factors	(250)	(65)	(316)
December 31, 2025(1)	**32,869**	**20,199**	**53,068**

(1) May not add due to rounding.

The 2025 drilling program resulted in proved plus probable producing extensions of 1,504 Mboe and proved plus probable undeveloped extensions of 4,585 Mboe attributed to the addition 52 (38.0 net) undeveloped locations.

The negative proved plus probable reserves technical revision was driven by performance adjustments in the Edson property (-1,668 Mboe) while Heavy Oil properties had positive revisions. Figure Lake had positive revisions, in aggregate, from producing well performance, gas conservation, and increase to Edwand sub-area type curve EURs (+407 Mboe). Other positive technical revisions in Frog Lake, Ukalta and Marten Hills (+107 Mboe) further offset the negative revision from Edson.

F&D Costs and Ratios[1]

($ thousands, except as noted)	2025 PDP	2025 1P	2025 2P	2024 PDP	2024 1P	2024 2P
Total Capital Expenditures[1]	**129,973**	**129,973**	**129,973**	95,373	95,373	95,373
Acquisitions (net of Dispositions)	**—**	**—**	**—**	189,683	189,683	189,683
Change in Future Development Capital ("FDC")	**—**	**5,470**	**21,216**	—	187,586	291,180
Exploration and Development	**—**	**5,470**	**21,216**	—	77,762	121,363
Acquisitions (net of Dispositions)	**—**	**—**	**—**	—	109,824	169,817
Reserves Additions with Revisions and Economic Factors (Mboe)	**4,966**	**4,739**	**4,619**	14,636	25,058	39,319
Exploration and Development (Mboe)	**4,966**	**4,739**	**4,619**	3,231	4,877	7,271
Acquisitions (net of Dispositions) (Mboe)	**—**	**—**	**—**	11,405	20,180	32,047

(1) Non-GAAP financial or reserve measure or non-GAAP ratio. See "Non-GAAP and Other Financial and Reserves Measures" in this Annual Results report.

	2025 PDP	2025 1P	2025 2P	2024 PDP	2024 1P	2024 2P
Finding & Development Costs[1][2] ("F&D")($ per boe)	**26.17**	**28.58**	**32.73**	29.52	35.50	29.81
Finding, Development & Acquisition Costs[1][2][3] ("FD&A")($ per boe)	**26.17**	**28.58**	**32.73**	19.48	18.86	14.66
Recycle Ratio (F&D)[2]	**1.3**	**1.2**	**1.0**	2.5	2.6	3.4
Reserve Replacement[2]	**1.1**	**1.0**	**1.0**	6.3	10.8	16.9

(1) Includes change in future development capital ("FDC") for 1P and 2P.
(2) Non-GAAP financial or reserve measure or non-GAAP ratio. See "Non-GAAP and Other Financial and Reserves Measures" in this Annual Results report.
(3) No lands with reserves assigned were acquired or disposed of in 2025.

Total capital expenditures[1], less corporate spending, of $130.0 million, plus the change in FDC of $21.2 million for newly recognized drilling locations, resulted in total proved plus probable additions of 6.1 MMboe for year-end 2025, offset by negative technical revisions of 1.2 MMboe and negative economic factors of 0.3 MMboe, for total additions year-over-year of 4.6 MMboe.

The 2P additions of 4.6 MMboe and total capital expenditures[1], less corporate spending, of $130.0 million, plus the change in FDC of $21.2 million, result in corporate F&D costs of $32.73/boe with a recycle ratio[1] of 1.0 based on 2025 operating netbacks[1] of $34.22/boe.

F&D costs per boe[1] for the Eastern Heavy Oil CGU were $27.08/boe on a PDP basis and $25.56/boe on a P+PDP basis with a recycle ratio[1] of 1.7 and 1.8, respectively. F&D costs per boe calculated using exploration and development spending only, results in a ratio of $22.16/boe on a P+PDP basis (the calculation includes all capital and reserves related to wells drilled in 2025 including drilling, completions, pad-site construction, and associated facilities), with a recycle ratio of 2.0 based on 2025 heavy oil operating netbacks[1] of $45.15/boe.

(1) Non-GAAP financial or reserve measure or non-GAAP ratio. See "Non-GAAP and Other Financial and Reserves Measures" in this Annual Results report.

Adjusted F&D Ratios[1]

For Rubellite, if total capital expenditures of $130.0 million were reduced by the cash proceeds of $7.8 million received for undeveloped land with no reserves assigned, the Adjusted F&D costs per boe[1] on a 2P basis were $31.05/boe with a recycle ratio[1] of 1.1 based on 2025 operating netbacks[1] of $34.22/boe.

In the Eastern Heavy Oil CGU, if total capital expenditures of $115.9 million were reduced by the cash proceeds of $7.8 million received for undeveloped land, including a $36.4 million change in FDC and 2P reserve additions of 6.3 MMboe, the Adjusted F&D costs per boe[1] on a 2P basis were $22.93/boe with a recycle ratio[1] of 2.0 based on 2025 heavy oil operating netbacks of $45.15/boe.

Adjusted F&D costs per boe[1] in 2025 for the Eastern Heavy Oil CGU were $25.26/boe on a PDP basis and $23.85/boe on a P+PDP basis with a recycle ratio[1] of 1.8 and 1.9, respectively based on 2025 heavy oil operating netbacks[1] of $45.15/boe.

(1) Non-GAAP financial or reserve measure or non-GAAP ratio. See "Non-GAAP and Other Financial and Reserves Measures" in this Annual Results report.

NET ASSET VALUE ("NAV")

The following reserve-based NAV[1] table shows what is referred to as a "produce-out" NAV calculation under which the Company's proved plus probable reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It should not be assumed that the NAV represents the fair market value of Rubellite's shares. The calculations below do not reflect the value of the Company's prospect inventory to the extent that the prospects are not recognized within the NI 51-101 compliant reserve assessment, except as they are valued through the estimate of the fair market value of undeveloped land.

Pre-tax NAV[1] at December 31, 2025[2]

		Discounted at		
($ millions, except as noted)	**Undiscounted**	**5%**	**10%**	**15%**
Developed reserves[3]	477.1	416.1	362.0	320.4
Undeveloped reserves[3]	601.3	413.5	294.4	214.9
Fair market value of undeveloped land[4]	59.6	59.6	59.6	59.6
Net debt[1][2]	(143.1)	(143.1)	(143.1)	(143.1)
Other provision[2]	(16.2)	(16.2)	(16.2)	(16.2)
NAV[1]	**978.6**	**729.9**	**556.6**	**435.5**
Common shares outstanding (million)[5]	93.6	93.6	93.6	93.6
NAV per share ($/share)[1][5][6]	**$ 10.46**	**$ 7.80**	**$ 5.95**	**$ 4.65**

(1) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial and Reserves Measures".
(2) Financial information is per Rubellite's 2025 audited consolidated financial statements.
(3) Proved plus probable developed and proved plus probable undeveloped reserve values per the McDaniel Report, including adjustments for risk management contracts. All abandonment and reclamation obligations, including future abandonment and reclamation costs for pipelines and facilities and non-reserve wells, are included in the McDaniel Report.
(4) Independent third-party estimate as per the Seaton-Jordan Report; excludes undeveloped lands where reserves are assigned.
(5) Common shares outstanding are net of shares held in trust.
(6) NAV per share is calculated by dividing the NAV by the number of issued and outstanding common shares, net of shares held in trust, at December 31, 2025.

OUTLOOK AND GUIDANCE

For the first quarter of 2026, Rubellite is forecasting a total of $30 to $32 million in exploration and development spending[1]. In addition to development drilling in its core operating areas, capital spending in Q1 2026 will support longer term strategic initiatives including: (1) advancing multiple EOR pilots in the Clearwater, with water injection at six waterflood pilots expected to have been initiated by mid-2026; (2) the producer-injector pair drilled for a polymer flood pilot planned to begin injection in Q4 2026; (3) additional injection/production cycles in the novel gas injection EOR pilot at Figure Lake; and (4) ongoing exploration activities.

First quarter capital projects in the Company's core properties include:

At Figure Lake:
- Drilling and completion of 4 (4.0 net) 15,000m, 12 leg, Clearwater development wells on the 8-26 Pad;
- Drilling and completion of 1 (1.0 net) 10,000m, 8 leg, waterflood pilot producer-injector pair on the 8-26 Pad;
- Drilling of 1 (1.0 net) 10,000m, 8 leg, polymer flood pilot producer-injector pair on the 8-26 Pad, the producer is expected to be drilled over quarter end and included in the Q2 2026 well count and the injector drilled in Q2 2026;
- Completion and initiation of water injection at the 9-35 Pad waterflood pilot producer-injector pair drilled in Q4 2025;
- Conversion of up to two existing mature multi-lateral producers to waterflood injectors; and
- Additional core testing to continue to inform EOR initiatives.

At Ukalta:
- Conversion of an existing mature multi-lateral producer to waterflood injector with water injection expected to begin in Q2 2026.

At Frog Lake:
- Drilling and completion of 3 (2.5 net) South Waseca wells; and
- Spending to finish shooting and processing the 3D seismic survey initiated in Q4 2025 to assist in positioning wells in the geologically complex Mannville Stack targets.

At East Edson:
- Participation in the drilling, completion, equipping and tie-in of 2 (1.0 net) Wilrich development wells initiated in late 2025.

In addition, first quarter 2026 spending will include capital to drill 1 (1.0 net) exploration well on a new venture prospect.

Factoring in the positive initial performance from the fourth quarter of 2025 and first quarter of 2026 drilling program to date, heavy oil sales volumes are expected to average between 8,300 to 8,400 bbl/d in the first quarter of 2026, while total production sales volumes, including natural gas and NGL volumes at East Edson and Figure Lake, are forecast to average 13,300 to 13,400 boe/d in the first quarter of 2026, for growth of approximately 2% relative to the fourth quarter of 2025.

Rubellite will closely monitor the production performance of the recent drilling program and anticipates providing full year guidance with the issuance of its Q1 2026 results in May.

Capital spending activity is expected to be funded from adjusted funds flow[(1)], with any excess free funds flow[(1)] used to reduce net debt[(1)] and for other balance sheet obligations.

Initiatives to improve field operating costs and reduce transportation costs in Rubellite's Clearwater and Mannville Stack production will continue to keep operating costs low at $6.50 to $7.25/boe guided for the first quarter of 2026 and transportation costs are expected to be in the $4.50 to $5.00/boe range. Blending demand for Clearwater and Mannville Stack heavy oil is expected to continue to translate into attractive offsets to WCS benchmark pricing, resulting in heavy oil wellhead differential guidance in the range of $3.50 to $4.00 per bbl.

Rubellite will continue to address end of life asset retirement obligations ("ARO"), with total abandonment and reclamation expenditures of approximately $0.8 million planned for the first quarter of 2026 to progress its AER area-based mandatory spending requirement for 2026 of $1.4 million.

(1) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial and Reserves Measures".

Planned exploration and development spending and drilling activity for the first quarter of 2026 is summarized in the table below:

	Q1 2026	
	Exploration and Development Spending ($ millions)[(2)]	**# of wells (gross/net)**
Figure Lake[(1)]		6 / 6.0
Frog Lake		3 / 2.5
Marten Hills		-/-
East Edson		2 / 1.0
Exploration		1 / 1.0
Total	**$30 - $32**	**12 /10.5**

(1) Includes one waterflood injection well.
(2) Excludes abandonment and reclamation spending, acquisitions and land and geological expenditures, if any.

Rubellite’s financial and operational guidance for the first quarter of 2026 is presented in the table below:

	Q1 2026 Guidance
Sales Production (boe/d)	13,300 - 13,400
Production mix (% oil and liquids)[(1)]	67%
Heavy Oil Production (bbl/d)	8,300 - 8,400
Exploration and Development spending ($ millions)[(2)(3)]	$30 - $32
Heavy oil wellhead differential ($/bbl)[(2)]	$3.50 - $4.00
Royalties (% of revenue)[(2)]	13% - 14%
Production and operating costs ($/boe)[(2)]	$6.50 - $7.25
Transportation costs ($/boe)[(2)]	$4.50 - $5.00
General and administrative costs ($/boe)[(2)]	$3.00 - $3.50

(1) Liquids means oil, condensate, ethane, propane and butane.
(2) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial and Reserves Measures".
(3) Excludes abandonment and reclamation, land, geological and acquisition expenditures, if any.

MANAGEMENT’S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of Rubellite Energy Corp.'s ("Rubellite", the "Company" or the "Corporation") operating and financial results for the three months and year ended ended December 31, 2025, as well as the information and estimates concerning the Corporation's future outlook based on currently available information. This discussion should be read in conjunction with the Corporation's audited consolidated financial statements and accompanying notes for the years ended December 31, 2025 and 2024. The Corporation's financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using IFRS Accounting Standards ("IFRS") as issued by the International Accounting Standards Board. The date of this MD&A is March 10, 2026.

This MD&A contains specified financial measures that are not recognized by GAAP and used by management to evaluate the performance of the Corporation and its business. Since certain specified financial measures may not have a standardized meaning, securities regulations require that specified financial measures are clearly defined, qualified and, where required, reconciled with their nearest GAAP measure. See "Non-GAAP and Other Financial Measures" for further information on the definition, calculation and reconciliation of these measures. This MD&A also contains "Forward-Looking Information". Readers are also referred to the other advisory sections at the end of this MD&A for additional information.

NATURE OF BUSINESS

The Company is a Canadian energy company headquartered in Calgary, Alberta engaged in the exploration, development, production and marketing of heavy crude oil from the Clearwater and Mannville Stack Formations in Eastern Alberta, as well as liquids-rich conventional natural gas assets in the deep basin of West Central Alberta, and undeveloped bitumen leases in Northern Alberta. The Company is pursuing a robust growth plan focused on heavy oil exploration and development utilizing multi-lateral, horizontal drilling technology, targeting superior corporate returns and free funds flow generation while maintaining a conservative capital structure and prioritizing operational excellence. Additional information on the Company can be accessed on the Company's website at www.rubelliteenergy.com or on SEDAR+ at www.sedarplus.ca.

The Company's common shares trade on the Toronto Stock Exchange under the symbol "RBY".

Prior Transactions

Recombination Transaction

On October 31, 2024, the Company, Rubellite Energy Inc. and Perpetual Energy Inc. ("Perpetual") closed a recombination transaction by way of an arrangement under Section 193 of the Business Corporations Act (Alberta) (the "Recombination Transaction"). Comparative figures in the MD&A include Rubellite Energy Inc.'s results prior to the business combination and do not reflect any historical data from Perpetual. The conventional natural gas assets at East Edson acquired through the Recombination Transaction are included in the West Central cash generating unit ("CGU"). This MD&A contains certain information pertaining to the Company before and after giving effect to the Recombination Transaction. Any reference to information prior to October 31, 2024 are references to Rubellite Energy Inc. and any reference to information subsequent to October 31, 2024 are references to the Company. Accordingly, unless the context otherwise requires, references to the Company subsequent to October 31, 2024 shall mean "Rubellite Energy Corp." and references to the Corporation prior to October 31, 2024 shall mean "Rubellite Energy Inc.".

Buffalo Mission Acquisition

On August 2, 2024, Rubellite closed the acquisition of Buffalo Mission Energy Corp. ("Buffalo Mission") (the “BMEC Acquisition”), a private Mannville Stack-focused heavy oil producer in the Frog Lake area. The total consideration paid was $96.6 million, inclusive of $23.5 million of assumed net debt, which consisted of $62.7 million in cash and the issuance of 5.0 million common shares of Rubellite to certain shareholders of Buffalo Mission.

FOURTH QUARTER AND ANNUAL 2025 OPERATIONAL AND FINANCIAL HIGHLIGHTS

Sales Production Volumes

- **Heavy oil:** Averaged 8,295 bbl/d in the fourth quarter of 2025, up 7% from 7,754 bbl/d in the fourth quarter of 2024. Achieved record annual heavy oil sales production of 8,402 bbl/d, up 48% from 5,685 bbl/d in 2024 and above guidance of 8,325 to 8,400 bbl/d.
- **Total sales production:** Delivered record fourth quarter average sales production of 13,042 boe/d (67% heavy oil and natural gas liquids ("NGL")), up 26% from 10,386 boe/d (77% heavy oil and NGL) in the fourth quarter of 2024, and record annual sales production of 12,494 boe/d (70% heavy oil and NGL), up 97% from 6,349 boe/d (91% heavy oil and NGL) in 2024 and exceeding guidance of 12,325 to 12,400 boe/d.
- **Heavy oil new wells:** Brought 14 (12.5 net) heavy oil wells onstream at Figure Lake and Frog Lake in the fourth quarter, for a total of 46 (39.0 net) new heavy oil wells contributing to sales in 2025.
- **West Central natural gas new wells:** Added 2 (1.0 net) liquids-rich conventional natural gas wells to production at East Edson at the end of the third quarter and 2 (1.0 net) additional wells late in the fourth quarter of 2025.
- **Figure Lake gas plant:** With the initial facility start up in January and subsequent expansion in the second half of 2025, natural gas sales averaged 5.6 MMcf/d in the fourth quarter and 3.4 MMcf/d in 2025.

Capital Expenditures

- **Exploration and development spending[(1)]:** Spent $34.8 million in the fourth quarter and $114.6 million for 2025, at the high end of the guided range of $110.0 to $115.0 million. Fourth quarter spending included the drilling, completion, equipping and tie-in of 6 (6.0 net) multi-lateral horizontal Clearwater development wells and 1 (1.0 net) multi-lateral horizontal Sparky well at Figure Lake; 4 (3.0 net) multi-lateral horizontal Waseca development wells and 3 (2.5 net) single leg horizontal wells in new zones at Frog Lake; and 2 (1.0 net) liquids-rich conventional natural gas wells at East Edson, bringing total 2025 drilling activity to 53 (43.8 net) wells.
- **Figure Lake gas plant:** Spent $0.7 million in the fourth quarter and $4.1 million in 2025 to finish initial construction and expand the gas plant and gas gathering system at Figure Lake, bringing processing capacity to 6.4 MMcf/d by the fourth quarter of 2025.
- **Land:** Spent $0.3 million in the fourth quarter, bringing total land costs to $10.5 million in 2025. In the fourth quarter, the Company sold 7 sections of undeveloped land, subject to a retained gross overriding royalty, for $2.3 million, bringing total proceeds from the disposition of non-producing acreage in 2025 to $7.8 million, which funded other capital activities.

- **Geological and geophysical costs:** Spent $3.8 million in the fourth quarter and $4.9 million in 2025 to shoot new 3D seismic and acquire trade data to support the development of the Clearwater and other Mannville Stack prospects, including the evaluation of new zones.

- **Abandonment and Reclamation:** Spent $0.6 million in the fourth quarter and $1.9 million in 2025 on decommissioning, abandonment and reclamation activities and received seven reclamation certificates from the Alberta Energy Regulator ("AER") (2024 - one), with two additional reclamation certificates received subsequent to year-end.

Financial Performance

- **Adjusted funds flow[(1)]:**
  - $33.2 million ($0.35 per share) in the fourth quarter of 2025, up 5% from $31.6 million ($0.36 per share) in the fourth quarter of 2024.
  - $142.1 million ($1.52 per share) in 2025, up 52% (12% per share) from 2024 driven by a 97% increase in sales volumes and 20% lower cash costs, partially offset by a 10% decrease in average realized prices.

- **Cash costs[(1)]:**
  - $18.5 million or $15.41/boe in the fourth quarter of 2025, 21% lower on a per boe basis than the fourth quarter of 2024 (Q4 2024 - $18.6 million or $19.45/boe).
  - $78.6 million or $17.24/boe in 2025, 20% lower on a per boe basis than 2024 (2024 - $50.4 million or $21.68/boe).

- **Net income:**
  - $9.7 million ($0.10 per share) in fourth quarter of 2025 (Q4 2024 - $26.7 million net income or $0.31 per share).
  - $32.6 million ($0.35 per share) in 2025 (2024 - $50.0 million or $0.73 per share).

Balance Sheet and Liquidity

- **Net debt[(1)]:** $143.1 million at December 31, 2025, down 7% from $154.0 million at December 31, 2024, driven by $11.6 million of positive free funds flow[(1)] used to reduce net debt and other obligations.

- **Available liquidity[(2)]:** $46.0 million at December 31, 2025, based on a $140.0 million first-lien credit facility borrowing limit, less $92.6 million of bank borrowings and $1.4 million in letters of credit.

(1) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(2) See "Liquidity, Capitalization and Financial Resources - Capital Management".

2025 GUIDANCE RECONCILIATION

During 2025, Rubellite recorded strong growth from a successful drilling program, which saw both heavy oil and total sales production exceed the high end of the 2025 guidance range. A comparison of the Company's most recent 2025 guidance metrics to actual results is provided below.

	2025 Guidance[(1)]	2025 Actuals
Sales Production (boe/d)	12,325 - 12,400	12,494
Production mix (% liquids)[(2)]	70%	70%
Heavy oil sales production (bbl/d)	8,325 - 8,400	8,402
Exploration and development spending ($ millions)[(3)(4)]	$110 - $115	$114.6
Heavy oil wellhead differential ($/bbl)[(3)]	$3.75 - $4.00	$3.76
Royalties (% of revenue)[(3)]	13% - 14%	13%
Production and operating costs ($/boe)[(3)]	$6.50 - $7.00	$6.48
Transportation costs ($/boe)[(3)]	$5.25 - $5.50	$5.18
General and administrative costs ($/boe)[(3)]	$3.00 - $3.50	$3.48

(1) 2025 guidance dated November 5, 2025.
(2) Liquids means oil, condensate, ethane, propane and butane.
(3) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(4) Excludes abandonment and reclamation spending, land and acquisitions and geological expenditures, if any.

OPERATIONS UPDATE

Figure Lake

Rubellite drilled and rig released 4 (4.0 net) Clearwater development horizontal wells targeting the Wabiskaw Member of the Clearwater Formation in the fourth quarter, using the optimized 33 meter inter-leg spacing and 15,000 meters open hole length, bringing the 2025 total to 15 (15.0 net) development wells drilled with this design. Initial well performance continues to exceed expectations, with average[(1)] IP30/60 rates of 205 bbl/d (15 wells)/192 bbl/d (14 wells), as compared to the 2025 McDaniel Tier 1 type curve[(2)] IP30/60 of 201/193 bbl/d[(2)], which was revised up from the 2024 McDaniel Tier 1 type curve[(2)] IP30/60 of 177/169 bbl/d.

A waterflood pilot was also advanced in the fourth quarter, with an 8-leg horizontal multi-lateral producer and a dedicated 1-leg injection well drilled from the 9-35-63-18W4 Pad (the '9-35 Pad'). Each 4-leg set was drilled with 33 meter inter-leg spacing with a total open hole length for the 8 legs of approximately 8,500 meters. Water injection began in early March.

The Company continued its natural-gas re-injection pilot at the 01-13-063-18W4 pad (the '1-13 Pad'), on the same site as the Figure Lake 1-13 Gas Plant. The pilot injected ~25 MMcf into an existing multi-lateral well to confirm injectivity, followed by controlled flow back ahead of a second injection cycle planned for early 2026.

A well targeting the Sparky Formation (1.0 net) drilled in the fourth quarter is delivering encouraging results, with an IP30 rate of 286 bbl/d and water cuts below 10%. The well has 6 legs and approximately 7,750 meters of horizontal length. Follow up development on this discovery, and continuous production of the initial well, will require the construction of a permanent all season access road and expansion of the pad which is planned for second half 2026. The well will be shut in during spring breakup and will require interim temporary infrastructure to allow for production from the well to restart late in Q2 2026.

Subsequent to the end of the year, a single rig drilling program is continuing at the 8-26-61-16W4 pad (the '8-26 Pad') following up two successful step-out delineation wells drilled in 2024. During the first quarter of 2026, a total of 4 (4.0 net) primary producers, 1 (1.0 net) waterflood pilot producer and 1 (1.0 net) injector pair are expected to be drilled at the 8-26 Pad. A polymer producer and injector pilot pair is also planned for the 8-26 Pad, which are scheduled to drill over quarter end. Results to date on the 8-26 Pad have been positive, with the first well drilled recording an IP30 of 286 bbl/d and the second drill recording an IP15 of 335 bbl/d in the early stages of production.

In addition, two multi-lateral horizontal producer-to-injector conversions on two separate pads are also planned for the first quarter of 2026 to evaluate the impact of waterflood where historical production has occurred through primary multi-lateral drilling development. Learnings regarding the performance of the multiple Enhanced Oil Recovery ("EOR") pilot schemes being evaluated will inform future development plans.

Frog Lake

Rubellite drilled and rig released 7 (5.5 net) wells during the fourth quarter, which included 4 (3.0 net) Waseca South wells, 2 (1.5 net) General Petroleum ("GP") wells and 1 (1.0 net) Sparky well. The Waseca drilling program for 2025 on average slightly exceeded McDaniel type curve(2) assumptions as per the below:

- **Waseca North program:** 14 (10.0 net) wells achieved average IP30/IP60 rates of 133/112 bbl/d, as compared to the 2025 McDaniel type curve(2) of 122/117 bbl/d and the 2024 McDaniel type curve(2) of 107/104 bbl/d

- **Waseca South program:** 7 (5.5 net) wells achieved average IP30/IP60 rates of 153/145 bbl/d, as compared to the 2025 McDaniel type curve(2) of 145/145 bbl/d and the 2024 McDaniel type curve(2) of 150/150 bbl/d.

Four (3.0 net) GP wells were drilled using both single-leg and fishbone designs. All the wells were equipped with recycle strings to aid in the recovery of solids and sand from the horizontal section of the wells with the exception of an unlined fishbone well. Early IP30(1) performance across the completed wells ranged between 44–134 bbl/d, averaging 78 bbl/d. The McDaniel year-end 2025 type curve(2) for GP has an IP30/IP60 of 73/72 bbl/d. The Company is encouraged by the early performance of the GP wells and nearby offset activity, and continues to optimize well design for future development.

One (1.0 net) Sparky well was drilled but encountered lost circulation after ~40 meters of horizontal lateral length and drilling was suspended. After obtaining a bottom hole pressure, the well was equipped for an extended test period.

Approximately 26 km^2 of new 3D seismic was acquired in the fourth quarter of 2025 and into the first quarter of 2026 to support future drilling plans at Frog Lake. The 3D seismic shoot was originally planned for first quarter of 2026, but was accelerated into fourth quarter due to crew availability.

Rubellite continued its drilling program at Frog Lake over year-end and into the first quarter of 2026, completed the program, and then paused drilling activity in early February to allow the rig, which has been operating continuously for several years, to be serviced and recertified over the next several months. The recess is expected to be approximately 90 days and will: (1) allow Rubellite to observe performance from the recent secondary zone wells; (2) evaluate well design and operational learnings in these early stages of delineation of the GP and Sparky zones; and (3) understand partner elections for participation in the drilling program planned at Frog Lake in mid-2026.

East Edson

Net production at East Edson was 3,802 boe/d (11% liquids) for the fourth quarter and averaged 3,517 boe/d (10% liquids) in 2025, as 2 (1.0 net) wells drilled at the end of third quarter and two (1.0 net) wells drilled in the fourth quarter were fracked and placed on production. Subsequent to the reporting period, 2 (1.0 net) additional wells were rig released, completed, equipped and tied-in with a portion of capital spending and activity occurring in the fourth quarter of 2025.

Other Exploration

In addition to activity in the GP and Sparky zones at Frog Lake and the Sparky zone at Figure Lake, Rubellite continued advancing multiple new venture exploration prospects, including land capture and play concept de-risking initiatives while minimizing risked capital exposure.

(1) No development wells were excluded from the calculation of average results except by the criteria for producing days.
(2) Type curve assumptions are based on the total proved plus probable undeveloped reserves contained in the McDaniel Report as disclosed in the AIF available under the Company's profile on SEDAR+ at www.sedarplus.ca. Year-end 2024 McDaniel Figure Lake Tier 1 Type Curve type curve of 177 bbl/d (IP30) and 169 bbl/d (IP60) based on the reserves contained in the 2024 McDaniel Report, as disclosed in the Company's 2024 AIF. "McDaniel Report" means the independent engineering evaluation of the heavy crude oil and conventional natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026.

OUTLOOK AND GUIDANCE

For the first quarter of 2026, Rubellite is forecasting a total of $30 to $32 million in exploration and development spending(1). In addition to development drilling in its core operating areas, capital spending in Q1 2026 will support longer term strategic initiatives including: (1) advancing multiple EOR pilots in the Clearwater, with water injection at six waterflood pilots expected to have been initiated by mid-2026; (2) the producer-injector pair drilled for a polymer flood pilot planned to begin injection in Q4 2026; (3) additional injection/production cycles in the novel gas injection EOR pilot at Figure Lake; and (4) ongoing exploration activities.

First quarter capital projects in the Company's core properties include:

At Figure Lake:
- Drilling and completion of 4 (4.0 net) 15,000m, 12 leg, Clearwater development wells on the 8-26 Pad;
- Drilling and completion of 1 (1.0 net) 10,000m, 8 leg, waterflood pilot producer-injector pair on the 8-26 Pad;
- Drilling of 1 (1.0 net) 10,000m, 8 leg, polymer flood pilot producer-injector pair on the 8-26 Pad, the producer is expected to be drilled over quarter end and included in the Q2 2026 well count and the injector drilled in Q2 2026;
- Completion and initiation of water injection at the 9-35 Pad waterflood pilot producer-injector pair drilled in Q4 2025;
- Conversion of up to two existing mature multi-lateral producers to waterflood injectors; and
- Additional core testing to continue to inform EOR initiatives.

At Ukalta:
- Conversion of an existing mature multi-lateral producer to waterflood injector with water injection expected to begin in Q2 2026.

At Frog Lake:
- Drilling and completion of 3 (2.5 net) South Waseca wells; and
- Spending to finish shooting and processing the 3D seismic survey initiated in Q4 2025 to assist in positioning wells in the geologically complex Mannville Stack targets.

At East Edson:
- Participation in the drilling, completion, equipping and tie-in of 2 (1.0 net) Wilrich development wells initiated in late 2025.

In addition, first quarter 2026 spending will include capital to drill 1 (1.0 net) exploration well on a new venture prospect.

Factoring in the positive initial performance from the fourth quarter of 2025 and first quarter of 2026 drilling program to date, heavy oil sales volumes are expected to average between 8,300 to 8,400 bbl/d in the first quarter of 2026, while total production sales volumes, including natural gas and NGL volumes at East Edson and Figure Lake, are forecast to average 13,300 to 13,400 boe/d in the first quarter of 2026, for growth of approximately 2% relative to the fourth quarter of 2025.

Rubellite will closely monitor the production performance of the recent drilling program and anticipates providing full year guidance with the issuance of its Q1 2026 results in May.

Capital spending activity is expected to be funded from adjusted funds flow(1), with any excess free funds flow(1) used to reduce net debt(1) and for other balance sheet obligations.

Initiatives to improve field operating costs and reduce transportation costs in Rubellite's Clearwater and Mannville Stack production will continue to keep operating costs low at $6.50 to $7.25/boe guided for the first quarter of 2026 and transportation costs are expected to be in the $4.50 to $5.00/boe range. Blending demand for Clearwater and Mannville Stack heavy oil is expected to continue to translate into attractive offsets to WCS benchmark pricing, resulting in heavy oil wellhead differential guidance in the range of $3.50 to $4.00 per bbl.

Rubellite will continue to address end of life asset retirement obligations ("ARO"), with total abandonment and reclamation expenditures of approximately $0.8 million planned for the first quarter of 2026 to progress its AER area-based mandatory spending requirement for 2026 of $1.4 million.

(1) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial and Reserves Measures".

Planned exploration and development spending and drilling activity for the first quarter of 2026 is summarized in the table below:

	Q1 2026	
	Exploration and Development Spending ($ millions)(2)	**# of wells (*gross/net*)**
Figure Lake(1)		6 / 6.0
Frog Lake		3 / 2.5
Marten Hills		-/-
East Edson		2 / 1.0
Other Exploration		1 / 1.0
Total	**$30 - $32**	**12 /10.5**

(1) Includes one waterflood injection well.
(2) Excludes abandonment and reclamation spending, land and acquisitions and geological expenditures, if any.

Rubellite's financial and operational guidance for the first quarter of 2026 is presented in the table below:

	Q1 2026 Guidance
Sales Production (boe/d)	13,300 - 13,400
Production mix (% liquids)(1)	67%
Heavy oil sales production (bbl/d)	8,300 - 8,400
Exploration and development spending ($ millions)(2)(3)	$30 - $32
Heavy oil wellhead differential ($/bbl)(2)	$3.50 - $4.00
Royalties (% of revenue)(2)	13% - 14%
Production and operating costs ($/boe)(2)	$6.50 - $7.25
Transportation costs ($/boe)(2)	$4.50 - $5.00
General and administrative costs ($/boe)(2)	$3.00 - $3.50

(1) Liquids means oil, condensate, ethane, propane and butane.
(2) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(3) Excludes abandonment and reclamation spending, land and acquisitions and geological expenditures, if any.

FOURTH QUARTER 2025 FINANCIAL AND OPERATING RESULTS

Capital Expenditures

Rubellite uses capital expenditures to measure its capital investments compared to the Company's annual budgeted expenditures related to both property, plant and equipment assets ("PP&E") and exploration and evaluation assets ("E&E") assets. The capital budget excludes acquisition and disposition activities. "Capital Expenditures" is not a standardized measure; therefore, may not be comparable with the calculation of similar measures by other entities. For a reconciliation of cash flow used in investing activities to capital expenditures, refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A.

The following tables summarize capital expenditures for both PP&E and E&E assets, excluding non-cash items:

	Three months ended December 31,					
	2025			2024		
($ thousands)	**E&E**	**PP&E**	**Total**	E&E	PP&E	Total
Drilling and completions	**89**	**30,503**	**30,592**	2,028	26,684	28,712
Facilities	**—**	**4,196**	**4,196**	255	5,431	5,686
Exploration and development spending(1)	**89**	**34,699**	**34,788**	2,283	32,115	34,398
Land and other	**346**	**—**	**346**	561	450	1,011
Geological and geophysical	**276**	**3,494**	**3,770**	—	—	—
Corporate	**—**	**133**	**133**	—	128	128
Total capital expenditures(1)	**711**	**38,326**	**39,037**	2,844	32,693	35,537

(1) Non-GAAP financial measure or supplementary financial measure. See "Non-GAAP and Other Financial Measures".

	Twelve months ended December 31,					
	2025			2024		
($ thousands)	**E&E**	**PP&E**	**Total**	E&E	PP&E	Total
Drilling and completions	**1,168**	**96,000**	**97,168**	10,831	74,365	85,196
Facilities	**236**	**17,166**	**17,402**	747	15,789	16,536
Exploration and development spending(1)	**1,404**	**113,166**	**114,570**	11,578	90,154	101,732
Land and other	**4,516**	**5,940**	**10,456**	3,495	526	4,021
Geological and geophysical	**1,453**	**3,494**	**4,947**	56	—	56
Corporate(2)	**—**	**529**	**529**	—	3,097	3,097
Total capital expenditures(1)	**7,373**	**123,129**	**130,502**	15,129	93,777	108,906

(1) Non-GAAP financial measure or supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(2) Prior to the Recombination Transaction, Rubellite had a MSA in place with Perpetual whereby Rubellite made payments for certain technical, capital and administrative services provided to Rubellite on a relative production split cost sharing basis. Corporate assets in 2024 include costs billed under the MSA for shared office leasehold improvements.

Exploration and Development Spending by CGU

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands)	**2025**	2024	**2025**	2024
Eastern Heavy Oil	**27,713**	33,699	**100,487**	101,033
West Central	**7,075**	699	**14,083**	699
Capital expenditures(1)	**34,788**	34,398	**114,570**	101,732

(1) Excludes land, geological and geophysical, corporate and other capital expenditures; Non-GAAP measure. See "Non-GAAP and Other Financial Measures".

Wells drilled by area

	Three months ended December 31,		Twelve months ended December 31,	
(gross/net)	**2025**	2024	**2025**	2024
Development				
Figure Lake(1)	**7 / 7.0**	9 / 9.0	**21 / 21.0**	34 / 34.0
Frog Lake(2)(3)	**7 / 5.5**	5 / 3.0	**26 / 19.5**	10 / 5.5
Marten Hills waterflood injection(4)	**-/-**	- / -	**1 / 0.3**	- / -
Edson(5)	**2 / 1.0**	- / -	**4 / 2.0**	- / -
Exploration				
Other exploratory(6)	**- / -**	1 / 1.0	**1 / 1.0**	2 / 2.0
Total	**16 / 13.5**	15 / 13.0	**53 / 43.8**	46 / 41.5

(1) 1 (1.0 net) well drilled at Figure Lake was spud on December 30, 2025 and rig released January 17, 2026 and not included in the Q4 2025 well count.
(2) 1 (1.0 net) well drilled at Frog Lake was spud on December 16, 2025 and rig released on January 10, 2026 and not included in the Q4 2025 well count.
(3) Four wells drilled in Q4 2025 and thirteen wells drilled in 2025 were at 100% working interest. Frog Lake Energy Resources Corp. ("FLERC") has the option on wells drilled in Frog lake to elect for a 50% working interest in a well or earn a gross overriding royalty.
(4) 1 (0.3 net) injection waterflood well was drilled at Marten Hills on the 12-35 Pad during Q1 2025.
(5) 2 (1.0 net) wells drilled at East Edson were spud in December 2025 and rig released in January 2026 and not included in the Q4 2025 well count.
(6) 1 (1.0 net) horizontal evaluation well was drilled in Q1 2025 and 1 (1.0 net) vertical stratigraphic evaluation well was drilled in Q1 2024. The costs associated with these two wells were transferred to E&E expense in Q1 2025.

Capital Expenditures

During 2025, the Company spent $114.6 million on exploration and development spending, before land, geological and geophysical and other corporate spending (2024 - $101.7 million). Capital program activities in 2025 included the following:

- At Figure Lake, the Company drilled 21 (21.0 net) wells at Figure Lake and completed and brought on production 21 (21.0 net) wells. At Figure Lake all of the wells drilled targeted the Clearwater formation, with the exception of 1 (1.0 net) Sparky multi-lateral drilled late in the fourth quarter. In addition, facilities spending included $4.1 million to expand the gas plant and gas gathering system.
- At Frog Lake, 26 (19.5 net) wells were drilled and 25 (18.0 net) wells were bought on production. The Company drilled 21 (16.0 net) Waseca South wells, 4 (2.5 net) GP wells, and 1 (1.0 net) Sparky well.
- At Marten Hills, the Company drilled 1 (0.3 net) waterflood injection well.
- At East Edson, 4 (2.0 net) Wilrich horizontal multi-stage frac stimulated wells were drilled, completed and brought on production. In addition, $2.9 million was spent at East Edson for lease construction, facility improvements and pipelines to support the ongoing drilling program with the Company's 50% joint venture partner.
- A portion of capital to drill 1 (1.0 net) additional well at Figure Lake, 1 (1.0 net) additional well at Frog Lake and 2 (1.0 net) additional wells at East Edson was spent during the fourth quarter with all wells rig released early in the first quarter of 2026.

Land spending totalled $10.5 million in 2025 to capture acreage in core areas and for exploration prospects (2024 - $4.0 million). Geological and geophysical spending totaled $4.9 million (2024 - $0.1 million) and was primarily related to purchasing or shooting seismic to assess core area lands prospective for development in the Clearwater and Mannville Stack formations.

The Company disposed of undeveloped lands for proceeds of $7.8 million in 2025, recording a corresponding gain on disposition.

Rubellite spent $1.9 million (2024 - $0.5 million) on abandonment and reclamation projects and received seven reclamation certificates from the AER (2024 - one). Subsequent to December 31, 2025, the Company received two additional reclamation certificates.

Sales Production

	Three months ended December 31,		Twelve months ended December 31,	
	2025	2024	**2025**	2024
Sales volumes				
Heavy oil (bbl/d)	**8,295**	7,754	**8,402**	5,685
Natural gas (Mcf/d)(1)	**25,884**	14,140	**22,361**	3,570
NGL (bbl/d)(2)	**433**	275	**365**	69
Total sales volumes (boe/d)	**13,042**	10,386	**12,494**	6,349

(1) Conventional natural gas production at East Edson yielded a heat content of 1.18 GJ/Mcf during the three and twelve months ended December 31, 2025 (three and twelve months ended December 31, 2025 - 1.18 GJ/Mcf) resulting in higher realized natural gas prices on a $/Mcf basis.
(2) Primarily from West Central CGU which produces liquids-rich conventional natural gas.

Sales production for the three and twelve months ended December 31, 2025 by CGU:

	Three months ended December 31,		Twelve months ended December 31,	
	2025	2024	**2025**	2024
Sales volumes by CGU				
Eastern Heavy Oil (boe/d)(1)	**9,240**	7,759	**8,977**	5,689
West Central (boe/d)(2)	**3,802**	2,627	**3,517**	660
Total sales volumes (boe/d)	**13,042**	10,386	**12,494**	6,349

(1) Primarily from the Clearwater and Mannville Stack formations in Eastern Alberta and includes natural gas sales at Figure Lake.
(2) Acquired through the Recombination Transaction with Perpetual in Q4 2024, which includes assets at East Edson that produce liquids-rich conventional natural gas.

Sales production for the three and twelve months ended December 31, 2025 increased by 2,656 boe/d (26%) and 6,145 boe/d (97%) from the comparative periods in 2024. Growth was driven by the Company's successful drilling program, solution gas tie-in at Figure Lake gas plant, the BMEC Acquisition at Frog Lake in the third quarter of 2024 and the Recombination Transaction with Perpetual in the fourth quarter of 2024. Heavy oil sales averaged 8,402 bbl/d in 2025, exceeding guidance of 8,325 to 8,400 bbl/d, while total sales averaged 12,494 boe/d, above guidance of 12,325 to 12,400 boe/d.

During 2025, 46 (39.0 net) Eastern Heavy Oil wells were added to sales, including 14 (12.5 net) wells added in the fourth quarter. At year end, 3 (3.0 net) additional wells were recovering OBM drilling fluid and not yet contributing to sales. In the West Central area, 2 (1.0 net) liquids-rich conventional natural gas wells were added to sales at the end of the third quarter, followed by 2 (1.0 net) wells added at the end of the fourth quarter.

At Figure Lake, the gas plant contributed an average of 5.6 MMcf/d and 3.4 MMcf/d of natural gas sales on average during the three and twelve months ended December 31, 2025.

Assets acquired through the Recombination Transaction at East Edson contributed 3,802 boe/d and 3,517 boe/d of natural gas and NGL sales for the three and twelve months ended December 31, 2025 (Q4 2024 - 2,627 boe/d and 2024 - 660 boe/d). Assets acquired at Frog Lake through the BMEC Acquisition added 2,985 bbl/d and 2,663 bbl/d of heavy oil sales for the three and twelve months ended December 31, 2025 (Q4 2024 - 2,210 bbl/d; 2024 - 940 bbl/d).

Rubellite's 2025 sales product mix averaged 70% heavy oil and NGL and 30% natural gas (2024 - 91% and 9%, respectively), reflecting the full-year impact of the Recombination Transaction and increased solution gas conservation at Figure Lake. The fourth quarter product mix was 67% heavy oil and NGL and 33% natural gas (Q4 2024 - 77% and 23%, respectively) driven by increased solution gas at Figure Lake and the East Edson drilling program in the second half of 2025.

Revenue

($ thousands, except as noted)	Three months ended December 31, **2025**	2024	Twelve months ended December 31, **2025**	2024
Oil and natural gas revenue				
Oil	**48,319**	54,912	**218,918**	164,206
Natural gas	**5,874**	2,618	**15,030**	2,627
NGL	**2,068**	1,551	**7,752**	1,551
Oil and natural gas revenue	**56,261**	59,081	**241,700**	168,384
Reference prices				
West Texas Intermediate (WTI) (US$/bbl)	**59.14**	70.27	**64.81**	75.72
Foreign Exchange rate (CAD$/US$)	**1.39**	1.40	**1.40**	1.37
WTI (CAD$/bbl)	**82.20**	98.38	**90.73**	103.74
Western Canadian Select (WCS) differential (US$/bbl)	**(11.20)**	(12.56)	**(11.13)**	(14.76)
WCS (CAD$/bbl)	**66.88**	80.74	**75.14**	83.52
Heavy oil wellhead differential (CAD$/bbl)	**3.56**	3.77	**3.76**	4.60
AECO 5A Daily Index (CAD$/GJ)	**2.21**	1.40	**1.62**	1.38
AECO 5A Daily Index (CAD$/Mcf)(1)	**2.34**	1.48	**1.71**	1.46
Rubellite average realized prices(2)				
Oil ($/bbl)	**63.32**	76.97	**71.38**	78.92
Natural gas ($/Mcf)	**2.47**	2.01	**1.84**	2.01
NGL ($/bbl)	**51.93**	61.32	**58.18**	61.32
Average realized price ($/boe)	**46.89**	61.83	**53.00**	72.46

(1) Converted from $/GJ using a standard energy conversion rate of 1.06 GJ:1 Mcf.
(2) Before risk management contracts; supplementary financial measure. See "Non-GAAP and Other Financial Measures".

Rubellite’s oil and natural gas revenue decreased by $2.8 million (5%) in the fourth quarter of 2025, reflecting lower realized prices driven by weaker benchmark prices and a shift in the product mix, partially offset by a 26% increase in sales volumes. For the twelve months ended December 31, 2025, revenue increased by $73.3 million (44%), driven primarily by a 97% increase in sales volumes, partially offset by lower realized prices on weaker benchmark pricing and changes in the product mix.

Oil revenue for the fourth quarter of 2025 was $48.3 million, representing 86% of total revenue, while heavy oil was 64% of total sales volumes. The 12% decline in oil revenue was due to an 18% reduction in average realized oil prices which offset the 7% increase in heavy crude oil sales volumes. The WCS price averaged $66.88/bbl in the fourth quarter (Q4 2024 - $80.74/bbl), reflecting the 16% decline in WTI oil prices and a slightly stronger Canadian dollar (CAD$/US$ rate $1.39 vs $1.40 in Q4 2024), partially offset by a narrowing of the WCS differential to US$11.20/bbl (Q4 2024 - US$12.56/bbl).

For the twelve months ended December 31, 2025, oil revenue was $218.9 million, representing 91% of total revenue, while heavy oil production was 67% of total sales volumes. The 33% increase in oil revenue was driven by the 48% increase in heavy oil sales volumes, partially offset by a 10% decline in average realized oil prices. The WCS price averaged $75.14/bbl (2024 - $83.52/bbl), reflecting a 14% decline in WTI oil prices, partially offset by a weaker Canadian dollar (CAD$/US$ rate $1.40 vs $1.37 in 2024) and the narrowing of the WCS differential to US$11.13/bbl (2024 - US$14.76/bbl).

Rubellite's realized oil price reflects quality adjustments and optimization of sales delivery points, resulting in lower price offsets that averaged $3.56/bbl and $3.76/bbl for the three and twelve months ended December 31, 2025 (Q4 2024 - $3.77/bbl; 2024 - $4.60/bbl).

Natural gas revenue in the fourth quarter of 2025 was $5.9 million, representing 10% of total revenue, while natural gas production was 33% of total sales volumes. Natural gas pricing reflected an average AECO Daily Index price of $2.34/Mcf (Q4 2024 - $1.48/Mcf). For the twelve months ended December 31, 2025, natural gas revenue totaled $15.0 million, or 6% of total revenue, while natural gas production was 30% of total sales volumes and reflected an average AECO Daily Index price of $1.71/Mcf (2024 - $1.46/Mcf).

NGL revenue was $2.1 million in the fourth quarter of 2025, representing 4% of total revenue and 3% of total sales volumes. For the twelve months ended December 31, 2025, NGL revenue was $7.8 million, representing 3% of both total revenue and total sales volumes.

Risk Management Contracts

The Company uses “average realized prices after risk management contracts” which is not a standardized measure, and therefore may not be comparable with the calculation of similar measures by other entities. The measure is used by management to calculate Rubellite’s net realized price, taking into account the monthly settlements of financial crude oil and natural gas forward sales, differentials and foreign exchange contracts. These contracts are put in place to protect Rubellite’s adjusted funds flow from potential downside risk and volatility and to lock in economics on drilling programs and acquisitions.

The following table details realized and unrealized gains and losses on risk management contracts:

	Three months ended December 31,		Twelve months ended December 31,	
(*$ thousands, except as noted*)	**2025**	2024	**2025**	2024
Unrealized gain (loss) on risk management contracts				
Unrealized gain (loss) on oil contracts(1)	**2,413**	(9,840)	**4,598**	(8,744)
Unrealized loss on natural gas contracts	**(1,102)**	(3,508)	**(6,319)**	(3,508)
Unrealized gain (loss) on risk management contracts	**1,311**	(13,348)	**(1,721)**	(12,252)
Realized gain on risk management contracts				
Realized gain on oil contracts(1)	**1,721**	822	**4,456**	244
Realized gain on natural gas contracts	**1,049**	2,338	**6,915**	2,338
Realized gain on risk management contracts	**2,770**	3,160	**11,371**	2,582

(1) Includes gain (loss) on CAD/USD foreign exchange risk management contracts.

The following table calculates average realized prices after risk management contracts, which is not a standardized measure:

	Three months ended December 31,		Twelve months ended December 31,	
	2025	2024	**2025**	2024
Realized gain (loss) on risk management contracts				
Realized gain (loss) on oil contracts ($/bbl)(1)	**2.26**	1.15	**1.45**	0.12
Realized gain on natural gas contracts ($/Mcf)	**0.44**	1.80	**0.85**	1.79
Realized gain (loss) on risk management contracts ($/boe)	**2.31**	3.31	**2.49**	1.11
Average realized prices after risk management contracts(2)				
Oil ($/bbl)(1)	**65.58**	78.12	**72.83**	79.04
Natural gas ($/Mcf)	**2.91**	3.81	**2.69**	3.80
NGL ($/bbl)	**51.93**	61.32	**58.18**	61.32
Average realized price ($/boe)(2)	**49.20**	65.14	**55.49**	73.57

(1) Includes CAD/USD foreign exchange risk management contracts.
(2) Supplementary financial measure. See "Non-GAAP and Other Financial Measures".

The realized gain on risk management contracts was $2.8 million or $2.31/boe for the fourth quarter of 2025 (Q4 2024 - realized gain of $3.2 million or $3.31/boe). For the twelve month period ending December 31, 2025, realized gains totaled $11.4 million or $2.49/boe (2024 - realized gain of $2.6 million or $1.11/boe). Realized gains or losses reflect fluctuations relative to pricing on commodity contracts driven by changes in AECO, WTI and WCS differential benchmark prices as well as fluctuations in foreign exchange rates and the percentage of production volumes hedged.

The unrealized gain on risk management contracts was $1.3 million for the fourth quarter of 2025 (Q4 2024 – $13.3 million unrealized loss) and the unrealized loss was $1.7 million for the twelve month period ended December 31, 2025 (2024 - $12.3 million unrealized loss). Unrealized gains and losses represent the change in the mark-to-market value of risk management contracts for future periods as forward commodity prices and foreign exchange rates change. Unrealized gains and losses on risk management contracts are excluded from the Company's calculation of cash flow from operating activities as non-cash items. Risk management contract gains and losses vary depending on commodity prices and the nature and extent of the risk management contracts in place, which in turn, vary with the Company's assessment of commodity price risk, committed capital spending and other factors.

Royalties

	Three months ended December 31,		Twelve months ended December 31,	
(*$ thousands, except as noted*)	**2025**	2024	**2025**	2024
Royalty expenses	**7,371**	7,743	**32,454**	20,272
$/boe	**6.14**	8.10	**7.12**	8.72
Royalties *(% of revenue)(1)*	**13.1**	13.1	**13.4**	12.0

(1) Non-GAAP ratio. See "Non-GAAP and Other Financial Measures".

Royalties payable by the Company include Crown royalties payable to the Alberta provincial government, royalties payable to Indian Oil and Gas Canada ("IOGC") and freehold and gross overriding royalties ("GORR"). The relative mix between Crown, IOGC, freehold and GORR production as a percentage of total production can change the composition of royalties from one period to the next. Under the Alberta Modernized Royalty Framework ("MRF") and the Indian Oil and Gas Act, Crown and IOGC royalties range from 5% to 40% on wells where mineral rights are leased from either the Crown or through IOGC. The remainder of royalties relate to freehold and GORR interests, some of which are price sensitive and fluctuate with commodity pricing.

Total royalties were $7.4 million in the fourth quarter of 2025, a decrease from $7.7 million in the fourth quarter of 2024 on lower commodity prices, partially offset by higher production. In 2025, royalties totaled $32.5 million, an increase from $20.3 million in 2024, driven by higher production and an increased number of wells subject to a GORR, partially offset by weaker pricing.

On a per boe basis, royalties averaged $6.14/boe and $7.12/boe for the three and twelve months ended December 31, 2025, a decrease relative to 2024 as higher sales volumes and lower prices more than offset the increased GORR exposure.

In the fourth quarter of 2025, royalties as a percentage of revenue were consistent with the fourth quarter of 2024. In 2025, royalties as a percentage of revenue increased to 13.4% (2024 - 12.0%) driven by more wells reaching payout and therefore moving to higher GORR and post-payout Crown royalty rates and was within the guided range of 13% to 14%.

Net operating costs[1]

($ thousands, except as noted)	Three months ended December 31, **2025**	2024	Twelve months ended December 31, **2025**	2024
Net operating costs[1]	**6,957**	6,536	**29,550**	16,514
$/boe	**5.80**	6.84	**6.48**	7.11

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".

Total net operating costs increased to $7.0 million and $29.6 million for the three and twelve months ended December 31, 2025, compared to $6.5 million and $16.5 million in the comparative periods of 2024, reflecting higher production volumes.

On a per boe basis, net operating costs decreased by 15% to $5.80/boe in the fourth quarter of 2025 and 9% to $6.48/boe for 2025 (Q4 2024 - $6.84/boe; 2024 - $7.11/boe). The decrease reflects lower carbon taxes associated with the Figure Lake gas plant, with further reductions following April 2025 legislative changes, and operational efficiencies at Frog Lake. In addition, the largely fixed nature of the Company's operating cost structure allowed fixed costs to be spread over significantly higher production volumes relative to 2024. Net operating costs for 2025 averaged $6.48/boe, below the guided range $6.50/boe to $7.00/boe.

Transportation costs

($ thousands, except as noted)	Three months ended December 31, **2025**	2024	Twelve months ended December 31, **2025**	2024
Oil and NGL transportation costs	**4,803**	5,450	**21,019**	16,031
Natural gas transportation costs[1]	**681**	297	**2,604**	297
Total transportation costs	**5,484**	5,747	**23,623**	16,328
$/boe	**4.57**	6.01	**5.18**	7.03

(1) Natural gas transportation is comprised of the transportation costs associated with the Figure Lake gas plant and East Edson assets.

Transportation costs include clean oil trucking, NGL transportation and natural gas transportation from plant gate to commercial sales points. In the fourth quarter of 2025, transportation costs decreased to $5.5 million (Q4 2024 - $5.7 million) due to a reduction in trucking rates at both Figure Lake and Frog Lake, partially offset by higher sales volumes. In 2025, transportation costs were $23.6 million, up from $16.3 million in the comparative periods of 2024 as a result of higher sales volumes.

On a per boe basis, transportation costs of $4.57/boe were 24% lower than the fourth quarter of 2024 (Q4 2024 - $6.01/boe) and 26% lower in 2025 (2024 - $7.03/boe). These reductions were driven by improved trucking rates realized at Figure Lake and Frog Lake, as well as the addition of natural gas volumes which incur lower transportation costs than heavy oil assets. Transportation costs in 2025 averaged $5.18/boe lower than the guided range of $5.25/boe to $5.50/boe.

Operating netbacks

The following tables highlight Rubellite's operating netbacks for the three and twelve months ended December 31, 2025 and 2024**:**

	Three months ended December 31, 2025			Three months ended December 31, 2024		
($ thousands)	**Eastern Heavy Oil**	**West Central**	**Total**	Eastern Heavy Oil	West Central	Total
Revenue	**49,567**	**6,694**	**56,261**	54,915	4,166	59,081
Royalties	**(6,334)**	**(1,037)**	**(7,371)**	(6,950)	(793)	(7,743)
Net operating costs[1]	**(5,769)**	**(1,188)**	**(6,957)**	(5,492)	(1,044)	(6,536)
Transportation costs	**(4,844)**	**(640)**	**(5,484)**	(5,326)	(421)	(5,747)
Operating netback[1]	**32,620**	**3,829**	**36,449**	37,147	1,908	39,055
Realized gain on risk management contracts[2]	**—**	**—**	**2,770**	—	—	3,160
Total operating netback, after risk management contracts[1]	**32,620**	**3,829**	**39,219**	37,147	1,908	42,215

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized gain on risk management contracts in the fourth quarter of 2025 is comprised of $1.7 million gain on oil contracts and $1.0 million gain on gas contracts (Q4 2024 - $0.8 million gain on oil contracts and $2.3 million gain on gas contracts).

	Twelve months ended December 31, 2025			Twelve months ended December 31, 2024		
($ thousands)	**Eastern Heavy Oil**	**West Central**	**Total**	Eastern Heavy Oil	West Central	Total
Revenue	**221,386**	**20,314**	**241,700**	164,218	4,166	168,384
Royalties	**(29,342)**	**(3,112)**	**(32,454)**	(19,479)	(793)	(20,272)
Net operating costs[1]	**(22,961)**	**(6,589)**	**(29,550)**	(15,470)	(1,044)	(16,514)
Transportation costs	**(21,142)**	**(2,481)**	**(23,623)**	(15,907)	(421)	(16,328)
Operating netback[1]	**147,941**	**8,132**	**156,073**	113,362	1,908	115,270
Realized gain on risk management contracts[2]	**—**	**—**	**11,371**	—	—	2,582
Total operating netback, after risk management contracts[1]	**147,941**	**8,132**	**167,444**	113,362	1,908	117,852

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized gain on risk management contracts in 2025 is comprised of a $4.5 million gain on oil contracts and a $6.9 million gain on gas contracts (2024 - $0.2 million gain on oil contracts and $2.3 million gain on gas contracts).

($/boe)	Three months ended December 31, 2025 **Eastern Heavy Oil**	 **West Central**	 **Total**	Three months ended December 31, 2024 Eastern Heavy Oil	 West Central	 Total
Revenue	**58.31**	**19.14**	**46.89**	76.93	17.23	61.83
Royalties	**(7.45)**	**(2.96)**	**(6.14)**	(9.74)	(3.28)	(8.10)
Net operating costs[1]	**(6.79)**	**(3.40)**	**(5.80)**	(7.69)	(4.32)	(6.84)
Transportation costs	**(5.70)**	**(1.83)**	**(4.57)**	(7.46)	(1.74)	(6.01)
Operating netback[1]	**38.37**	**10.95**	**30.38**	52.04	7.89	40.88
Realized gain on risk management contracts[2]	**—**	**—**	**2.31**	—	—	3.31
Total operating netback, after risk management contracts[1]	**38.37**	**10.95**	**32.69**	52.04	7.89	44.19

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized gain on risk management contracts in the fourth quarter of 2025 is comprised of a $2.26/bbl gain on oil contracts and a $0.44/Mcf gain on gas contracts (Q4 2024 - $1.15/bbl gain on oil contracts and $1.80/Mcf gain on gas contracts).

($/boe)	Twelve months ended December 31, 2025 **Eastern Heavy Oil**	 **West Central**	 **Total**	Twelve months ended December 31, 2024 Eastern Heavy Oil	 West Central	 Total
Revenue	**67.57**	**15.82**	**53.00**	78.87	17.23	72.46
Royalties	**(8.96)**	**(2.42)**	**(7.12)**	(9.36)	(3.28)	(8.72)
Net operating costs[1]	**(7.01)**	**(5.13)**	**(6.48)**	(7.43)	(4.32)	(7.11)
Transportation costs	**(6.45)**	**(1.93)**	**(5.18)**	(7.64)	(1.74)	(7.03)
Operating netback[1]	**45.15**	**6.34**	**34.22**	54.44	7.89	49.60
Realized gain on risk management contracts[2]	**—**	**—**	**2.49**	—	—	1.11
Total operating netback, after risk management contracts[1]	**45.15**	**6.34**	**36.71**	54.44	7.89	50.71

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized gain on risk management contracts in 2025 is comprised of a $1.45/bbl gain on oil contracts and a $0.85/Mcf gain on gas contracts (2024 - $0.12/bbl gain on oil contracts and $1.79/Mcf gain on gas contracts).

Rubellite's Eastern Heavy Oil operating netback in the fourth quarter of 2025 decreased to $32.6 million (Q4 2024 - $37.1 million) driven primarily by lower revenue given the drop in oil prices combined with higher net operating costs, partially offset by lower royalty and transportation costs. In 2025, the Eastern Heavy Oil operating netback increased to $147.9 million (2024 - $113.4 million) as a result of higher sales volumes. On a per boe basis, operating netbacks declined on lower realized oil prices, partially offset by lower royalties, net operating costs and transportation costs.

Rubellite's West Central operating netback for the three and twelve months ended December 31, 2025 increased to $3.8 million and $8.1 million (Q4 2024 and 2024 - $1.9 million). On a per boe basis, the West Central operating netback in the fourth quarter of 2025 increased to $10.95/boe (Q4 2024 - $7.89/boe) reflecting higher prices and lower royalties and net operating costs, partially offset by higher transportation costs. In 2025, the West Central operating netback on a per boe basis decreased to $6.34/boe (2024 - $7.89/boe) reflecting lower prices and higher net operating and transportation costs, partially offset by lower royalties.

Rubellite's total operating netback for the three and twelve months ended December 31, 2025 were $36.4 million and $156.1 million (Q4 2024 - $39.1 million; 2024 $115.3 million). On a per boe basis, the decline reflects lower realized prices from lower oil pricing and the addition of natural gas into the sales mix. These impacts were partially offset by reduced royalties, net operating costs and transportation costs.

For the three and twelve months ended December 31, 2025, the operating netback, after realized gains on risk management contracts, was $32.69/boe and $36.71/boe (Q4 2024 – $44.19/boe; 2024 - $50.71/boe).

General and administrative ("G&A") expenses

($ thousands, except as noted)	Three months ended December 31, **2025**	 2024	Twelve months ended December 31, **2025**	 2024
G&A expenses – before MSA costs & recoveries	**5,837**	4,698	**21,784**	7,292
G&A recoveries	**(2,006)**	(1,687)	**(5,909)**	(1,687)
MSA costs[1]	**—**	511	**—**	5,011
Total G&A expenses	**3,831**	3,522	**15,875**	10,616
$/boe	**3.19**	3.69	**3.48**	4.57

(1) Prior to the Recombination Transaction, Rubellite Energy Inc. and Perpetual were considered related parties due to the existence of a Management and Operating Services Agreement ("MSA") and certain officers and directors being key management of, and having significant influence over, Rubellite Energy Inc. while also being key management of and having deemed control over Perpetual. Under the MSA, Rubellite Energy Inc. made payments to Perpetual for certain technical, capital and administrative services provided to Rubellite Energy Inc. on a relative cost sharing basis.

G&A expenses for the three and twelve months ended December 31, 2025 increased to $5.8 million and $21.8 million (Q4 2024 – $4.7 million; 2024 - $7.3 million). Prior to the Recombination Transaction, G&A expenses, excluding MSA costs, consisted primarily of legal fees, computer software licenses, insurance, professional fees and public company costs. Following completion of the Recombination Transaction, Rubellite's G&A expenses increased to include all G&A costs previously billed through the MSA including people, office and computer costs and recoveries.

On a per boe basis, G&A costs for the three and twelve months ended December 31, 2025 decreased to $3.19/boe and $3.48/boe from $3.69/boe and $4.57/boe in the comparative periods of 2024. The decrease reflects Rubellite's predominately fixed G&A cost structure being allocated over higher sales volumes in 2025. G&A costs in 2025 averaged $3.48/boe, in line with 2025 guidance of $3.00/boe to $3.50/boe.

Depletion

(*$ thousands, except as noted*)	Three months ended December 31, **2025**	2024	Twelve months ended December 31, **2025**	2024
Depletion	**23,761**	18,645	**92,181**	49,192
Depreciation	**532**	443	**2,062**	655
Total depletion and depreciation	**24,293**	19,088	**94,243**	49,847
($/boe)				
Depletion	**19.80**	19.51	**20.21**	21.17
Depreciation	**0.44**	0.46	**0.45**	0.28
$/boe	**20.24**	19.97	**20.66**	21.45

The Company calculates depletion using the net book value of the asset, future development costs associated with proved and probable reserves, salvage values on associated production equipment, as well as proved plus probable reserves. As at December 31, 2025, depletion was calculated on a $514.8 million depletable balance (December 31, 2024 – $473.4 million), $457.6 million in future development costs (December 31, 2024 – $436.3 million) and excluded an estimated $12.4 million of salvage value (December 31, 2024 – $8.7 million).

Depletion and depreciation expense for the fourth quarter of 2025 was $24.3 million or $20.24/boe (Q4 2024 – $19.1 million or $19.97/boe). For 2025, depletion and depreciation expense was $94.2 million or $20.66/boe (2024 - $49.8 or $21.45/boe). The increases for both periods reflect a higher depletable base driven by the BMEC Acquisition and the Recombination Transaction, which added significant producing assets and associated future development costs. On a per boe basis, fourth quarter 2025 depletion increased on higher production relative to reserves. In 2025, depletion per boe was lower as the Recombination Transaction added West Central assets with higher reserves relative to production resulting in a lower depletion rate when compared to Rubellite's Eastern Heavy Oil assets.

Depletion will fluctuate from one period to the next depending on the amount of capital spent, reserves additions and production volumes.

Impairment

Eastern Heavy Oil CGU

At December 31, 2025 and December 31, 2024, the Company assessed its Eastern Heavy Oil CGU for indicators of impairment and concluded that the estimation of recoverable amount was not required, therefore no impairment test was required.

The Company transferred $20.8 million of E&E to PP&E during 2024 and performed the required impairment test to estimate the recoverable amount of the CGU. It was determined that the recoverable amount of the CGU exceeded its carrying value, resulting in no impairment. The Company did not transfer E&E to PP&E during 2025, therefore no impairment test was required.

West Central CGU

At December 31, 2025, the Company completed an assessment to determine if indicators of impairment existed within the West Central CGU. As a result of the assessment, the Company determined that indicators of impairment existed at December 31, 2025 as the carrying amount of the CGU may exceed the recoverable amount. The Company performed the required impairment test using the value-in-use ("VIU") approach incorporating benchmark pricing based on the average of the three independent reserve evaluators' forecast and utilizing a discount rate of 15%. The test determined that the recoverable amount of the West Central CGU exceeded its carrying value as at December 31, 2025 and as a result, no impairment was recognized.

Finance expense

($ thousands)	Three months ended December 31, **2025**	2024	Twelve months ended December 31, **2025**	2024
Cash finance expense				
Interest on bank debt	**1,565**	2,149	**6,973**	5,897
Interest on term loan	**580**	580	**2,300**	952
Interest on lease liabilities	**78**	55	**316**	55
Total cash finance expense	**2,223**	2,784	**9,589**	6,904
$/boe	**1.85**	2.91	**2.10**	2.97
Non-cash finance expense				
Amortization of debt issue costs	**44**	62	**170**	63
Accretion on decommissioning obligations	**293**	108	**1,104**	316
Accretion on other provision	**114**	69	**480**	93
Total non-cash finance expense	**451**	239	**1,754**	472
$/boe	**0.38**	0.25	**0.38**	0.20
Finance expense	**2,674**	3,023	**11,343**	7,376

In the fourth quarter of 2025, total cash finance expense decreased to $2.2 million (Q4 2024 - $2.8 million) due to lower average outstanding bank debt and lower effective interest rates. For the twelve months ended December 31, 2025, total cash finance expense increased to $9.6 million (2024 - $6.9 million) as a result of the full year of interest expense related to the addition of the term loan in the third quarter of 2024, interest on lease liabilities assumed from the Recombination Transaction, and higher interest on bank debt driven by increased average borrowings in 2025. The effective aggregate interest rate on the Company's bank line averaged 5.6% in the fourth quarter and 6.0% in 2025 (Q4 2024 - 6.7%; 2024 - 8.2%). The interest rate on the term loan is 11.5%.

For the three and twelve months ended December 31, 2025, cash finance expense on a per boe basis decreased due to higher sales volumes.

Non-cash finance expense represents accretion on decommissioning obligations, accretion on the other provision and amortization of debt issue costs. For the three and twelve months ended December 31, 2025, non-cash finance expense increased over the comparative periods of 2024 due to higher decommissioning obligations and the addition of the other provision from the Recombination Transaction.

Deferred Income Taxes

	Three months ended December 31,		Twelve months ended December 31,	
	2025	2024	**2025**	2024
Income before income tax	**$ 9,123**	$ 28,839	**$ 41,441**	$ 59,033
Combined federal and provincial tax rate	**23%**	23%	**23%**	23%
Computed income tax expense	**2,098**	6,633	**9,532**	13,577
Increase (decrease) in income taxes resulting from:				
Non-deductible expenses	**38**	315	**524**	763
Non-taxable gain on acquisition	**—**	(7,272)	**—**	(7,272)
Other	**(204)**	(292)	**2**	(550)
Change in unrecognized deferred tax assets	**(2,509)**	2,876	**(1,174)**	2,542
Deferred tax expense (recovery)	**(577)**	2,260	**8,884**	9,060

In the fourth quarter of 2025, the Company recorded a deferred income tax recovery of $0.6 million, compared to a deferred tax expense of $2.3 million in the fourth quarter of 2024. The recovery reflects lower net income before taxes, along with a decrease in unrecognized deferred tax assets. In the comparative period, higher net income before taxes was largely offset by a non-taxable gain on acquisition and a decrease in unrecognized deferred tax assets, resulting in an overall deferred tax expense.

In 2025, the Company recorded a deferred income tax expense of $8.9 million, a slight decrease from $9.1 million in 2024. The expense reflects lower net income before taxes combined with a decrease in unrecognized deferred tax assets. In contrast, the prior year's deferred tax expense was influenced by higher net income before taxes, partially offset by a non-taxable gain on acquisition and an increase in unrecognized deferred tax assets.

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

Rubellite’s strategy targets the maintenance of a strong capital base to retain investor, creditor and market confidence to support the execution of its business plans. The Company manages its capital structure and adjusts its capital spending in light of changes in economic conditions, available liquidity, and the risk characteristics of its underlying assets. The Company considers its capital structure to include share capital, bank debt, term loans and adjusted working capital. To manage its capital structure and available liquidity, Rubellite may from time to time issue equity or debt securities, sell assets, and adjust its capital spending to manage current and projected debt levels. The Company will continue to regularly assess changes to its capital structure, with considerations for both short-term liquidity and long-term financial sustainability.

Capital Management

(*$ thousands, except as noted*)	**December 31, 2025**	December 31, 2024
Bank debt(1)	**92,583**	105,945
Term loan (principal)	**20,000**	20,000
Adjusted working capital deficit(1)(2)	**30,560**	28,075
Net debt(2)	**143,143**	154,020
Shares outstanding at end of period (*thousands*)	**93,593**	92,877
Market price at end of period (*$/share*)	**2.40**	2.12
Market value of shares(2)	**224,623**	196,899
Enterprise value(2)	**367,766**	350,919
Net debt as a percentage of enterprise value(2)	**39%**	44%
Trailing twelve months adjusted funds flow(2)	**142,073**	93,777
Net debt to trailing twelve months adjusted funds flow ratio(2)	**1.0**	1.6
Q4 annualized adjusted funds flow(2)(3)	**132,660**	143,420
Net debt to Q4 annualized adjusted funds flow ratio(2)(3)	**1.1**	1.1

(1) Bank debt shown net of cash balance of $2.6 million as at December 31, 2024. Adjusted working capital deficit excludes the cash balance of $2.6 million as at December 31, 2024.
(2) Non-GAAP measure or ratio. See "Non-GAAP and Other Financial Measures".
(3) Based on Q4 2025 adjusted funds flow, before transaction costs, of $33.2 million (Q4 2024 - $35.9 million). See "Non-GAAP and Other Financial Measures" for more details.

At December 31, 2025, Rubellite had net debt of $143.1 million, a 7% decrease from $154.0 million at December 31, 2024. Net debt decreased as adjusted funds flow of $142.1 million exceeded total capital expenditures, including land and other spending, of $130.5 million, generating $11.6 million of free funds flow. The positive free funds flow were primarily used to reduce net debt and other obligations, including a $3.8 million reduction of the other provision, $1.9 million of decommissioning expenditures and $3.2 million of cash-settled share based compensation payments.

Rubellite had available liquidity at December 31, 2025 of $46.0 million, comprised of the $140.0 million Credit Facility Borrowing Limit, less $92.6 million of bank borrowings and $1.4 million of outstanding letters of credit.

Bank debt

As at December 31, 2025, the Company's first lien credit facility had a borrowing limit of $140.0 million (December 31, 2024 - $140.0 million). The initial term is to May 31, 2026 and may be extended for a further twelve months to May 31, 2027 subject to lender approval. If not extended by May 31, 2026, all outstanding advances would be repayable on May 31, 2027. The next semi-annual borrowing base redetermination is scheduled on or before May 31, 2026.

As at December 31, 2025, $92.6 million was drawn against the credit facility (December 31, 2024 - $108.5 million) and $1.4 million (December 31, 2024 - $3.6 million) of letters of credit issued. Borrowings under the credit facility bear interest at the lenders' prime rate or CORRA rates, plus applicable margins and standby fees. The applicable CORRA margins range between 2.8% and 6.3%. The effective aggregate interest rate on the credit facility for the three and twelve months ended December 31, 2025 was 5.6% per annum and 6.0% per annum (Q4 2024 - 6.7% per annum; 2024 - 8.2% per annum). For the year ended December 31, 2025, if interest rates changed by 1% with all other variables held constant, the impact on cash finance expense and net income and comprehensive income would be $0.7 million.

The credit facility is secured by general first lien security agreements covering all present and future property of the Company.

At December 31, 2025, the credit facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Term Loan

			December 31, 2025		December 31, 2024	
($ thousands)	**Maturity date**	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term loan	August 2, 2029	11.5%	**20,000**	**19,173**	20,000	19,027

On August 2, 2024, concurrent with closing of the BMEC Acquisition, Rubellite entered into a $20.0 million senior secured second-lien term loan, placed, directly or indirectly with certain directors and officers, and their affiliates, of Rubellite and the Company's significant shareholder. The term loan bears interest at 11.5% annually with interest payments to be paid quarterly, matures in five years from the date of issue on August 2, 2029, and can be repaid by the Company without penalty at any time. In conjunction with the closing of the Recombination Transaction, the term loan was converted to a third-lien obligation of the Company.

During the three and twelve months ending December 31, 2025, Rubellite paid $0.6 and $2.3 million in cash interest payments to the holders of the term loan (Q4 2024 - $0.6 million; 2024 - $1.0 million).

At December 31, 2025, the term loan was recorded at the present value of future cash flows, net of $0.8 million (December 31, 2024 - $1.0 million) in issue and discount costs which are amortized over the remaining term using a weighted average effective interest rate of 13.0% (December 31, 2024 - 12.9%).

The term loan is not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

At December 31, 2025, entities controlled or directed by the Company's Chief Executive Officer ("CEO") hold $18.4 million of the outstanding term loan (December 31, 2024 - $18.4 million).

Equity

At December 31, 2025, there were 93.6 million common shares outstanding, net of 0.1 million shares held in trust for employee compensation programs (December 31, 2024 - 92.9 million common shares outstanding, net of 0.2 million of shares held in trust).

On August 2, 2024, in conjunction with the closing of the BMEC Acquisition, Rubellite issued 5.0 million common shares to certain shareholders of Buffalo Mission, which were valued at $10.4 million using the Company's share price on the closing date of the transaction of $2.07 per share.

On October 31, 2024, in conjunction with the closing of the Recombination Transaction, Rubellite issued 25.4 million common shares which were valued at $51.7 million using the Company's share price on the closing date of the transaction of $2.04 per share. At closing of the Recombination Transaction, 4.0 million Share Purchase Warrants, which were issued to Perpetual on September 3, 2021 valued at $2.0 million, were cancelled on October 31, 2024 and are no longer outstanding.

At March 10, 2026 there were 93.6 million common shares outstanding, net of 0.1 million shares held in trust for employee compensation programs.

The following table summarizes information about options and performance awards and restricted awards outstanding as the date of this MD&A:

(thousands)	**March 10, 2026**
Restricted share units	3,331
Share options	3,289
Performance share units	1,944
Perpetual awards(1)(2)	2,249
Total	**10,813**

(1) Legacy Perpetual awards from the Recombination Transaction include 0.9 million deferred options, 0.2 million deferred shares, 0.8 million share options and 0.3 million performance share rights. All Perpetual awards from the Recombination Transaction were adjusted both in number issued and exercise price by the exchange ratio of 5:1.
(2) Total awards outstanding include 1.6 million legacy Perpetual awards that can be settled for cash or from shares in the trust as opposed to treasury. There were 0.1 million shares held in the trust as at March 10, 2026.

Commodity price risk management

As at March 10, 2026, Rubellite had entered into the following oil commodity risk management contracts:

Commodity	Volumes Sold (bbl/d)	Term	Reference/Index	Contract Traded Bought/Sold	Average Price ($/bbl)
Crude Oil	1,500 bbl/d	Jan 2026	WTI (US$/bbl)	Swap - sold	$65.13
Crude Oil	3,500 bbl/d	Feb 2026	WTI (US$/bbl)	Swap - sold	$63.88
Crude Oil	6,100 bbl/d	Mar 2026	WTI (US$/bbl)	Swap - sold	$68.09
Crude Oil	5,350 bbl/d	Apr 2026	WTI (US$/bbl)	Swap - sold	$67.18
Crude Oil	4,350 bbl/d	May 2026	WTI (US$/bbl)	Swap - sold	$64.48
Crude Oil	4,350 bbl/d	Jun 2026	WTI (US$/bbl)	Swap - sold	$64.26
Crude Oil	3,800 bbl/d	Jul 2026 - Sep 2026	WTI (US$/bbl)	Swap - sold	$61.77
Crude Oil	2,900 bbl/d	Oct 2026 - Dec 2026	WTI (US$/bbl)	Swap - sold	$63.78
Crude Oil	750 bbl/d	Jan 2027 - Dec 2027	WTI (US$/bbl)	Swap - sold	$66.50
Crude Oil	1,000 bbl/d	Jan 2026 - Mar 2026	WCS Differential (US$/bbl)	Swap - sold	($12.50)
Crude Oil	4,000 bbl/d	Apr 2026 - Jun 2026	WCS Differential (US$/bbl)	Swap - sold	($12.61)
Crude Oil	3,500 bbl/d	Jul 2026 - Sep 2026	WCS Differential (US$/bbl)	Swap - sold	($12.44)
Crude Oil	2,000 bbl/d	Oct 2026 - Dec 2026	WCS Differential (US$/bbl)	Swap - sold	($13.00)

As at March 10, 2026, Rubellite had entered into the following natural gas commodity risk management contracts:

Commodity	Volumes Sold	Term	Reference/Index	Contract Traded Bought/Sold	Average Price ($/GJ)
Natural gas	5,000 GJ/d	Jan 2026 - Mar 2026	AECO 5A (CAD$/GJ)	Swap - sold	$4.00
Natural gas	5,000 GJ/d	Jan 2026 - Mar 2026	AECO 5A (CAD$/GJ)	Swap - bought	$3.31
Natural gas	5,276 GJ/d	Apr 2026 - Oct 2026	NYMEX (US$/GJ)	Swap - sold	$3.89

Foreign exchange risk management

As at March 10, 2026, Rubellite entered into the following foreign exchange risk management contracts:

Fixed Contract	Notional amount	Term	Price (CAD$/US$)
Average rate forward (CAD$/US$)	$2,500,000 US$/month	Jan - Dec 2026	1.4066
Average rate forward (CAD$/US$)	$5,000,000 US$/month	Jan - Dec 2026	1.3890

(1) At expiry on December 31, 2026 if the calendar 2027 forward strip is above 1.3890 CAD$/US$, Rubellite knocks into a $5.0 million US$/month contract at 1.3890 CAD$/US$ for the 2027 calendar year.

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

The Company has a drilling commitment on certain GORR lands that must be fulfilled by September 28, 2026 (the "Commitment Date"). If WTI settles below USD $60.00/bbl for a period of thirty consecutive days the agreement shall automatically extend for an additional 90 days. In the event the Company fails to fulfill the drilling commitment, the Company is required to pay $0.1 million per well not spud by the Commitment Date. As at December 31, 2025, the Company has drilled 29 (29.0 net) of the 59 (59.0 net) wells that are required to meet the drilling commitment. Subsequent to December 31, 2025, the Company has drilled an additional 5 (5.0 net) wells for a total of 25 (25.0 net) wells required to meet the drilling commitment.

PROVISIONS

Decommissioning obligations

Decommissioning obligations are estimated based on the Company’s net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities, and the estimated timing of the costs to be incurred in future periods.

The increase in the provision due to the passage of time, which is referred to as accretion, is recognized as non-cash finance expense in the consolidated statements of income and comprehensive income. Decommissioning obligations are further adjusted at each period end date for changes in the risk-free interest rate, after considering additions and dispositions of PP&E. Decommissioning obligations are also adjusted for revisions to future cost estimates and the estimated timing of costs to be incurred in future periods.

($ thousands)	**December 31, 2025**	December 31, 2024
Decommissioning obligations – current	**1,340**	2,000
Decommissioning obligations – non-current	**34,302**	29,817
Total decommissioning obligations	**35,642**	31,817

The following significant assumptions were used to estimate the Company's decommissioning obligations:

(*$ thousands, except as noted*)	**December 31, 2025**	December 31, 2024
Undiscounted obligations	**49,432**	42,085
Average risk-free rate	**3.9%**	3.3%
Inflation rate	**2.0%**	1.8%
Expected timing of settling obligations	**1 to 25 years**	1 to 25 years

Other provision

The other provision was assumed as part of the Recombination Transaction and relates to a "Settlement Agreement" Perpetual entered into to resolve litigation by providing amounts to settle asset retirement obligations without any party admitting liability, wrongdoing or violation of laws, regulations, public policy or fiduciary duties. The Company will make annual installment payments of $3.75 million until the total amount of the Settlement Principal is paid. The annual scheduled payment was made on March 28, 2025 and all scheduled payments made prior to March 28, 2026 will have the interest forgiven. As of March 28, 2026, interest will accrue and be payable on the outstanding Settlement Principal annually at an interest rate equal to the applicable Bank of Canada prime rate on the date of payment. The Company is able to pre-pay all, or any portion, of the outstanding balance of the Settlement Principal at any time without bonus or penalty.

($ thousands)	**December 31, 2025**	December 31, 2024
Other provision – current	**3,750**	3,750
Other provision – non-current	**11,554**	14,824
Total other provision	**15,304**	18,574

The following assumptions were used to estimate the other provision:

(*$ thousands, except as noted*)	**December 31, 2025**	December 31, 2024
Undiscounted obligations	**16,191**	19,941
Average risk-free rate	**3.0%**	3.0%
Expected timing of settling obligations	**4.3 years**	5.3 years

OFF BALANCE SHEET ARRANGEMENTS

Rubellite has no material off balance sheet arrangements.

NON-GAAP AND OTHER FINANCIAL MEASURES

Throughout this MD&A and in other materials disclosed by the Company, Rubellite employs certain measures to analyze financial performance, financial position and cash flow. These non-GAAP and other financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-GAAP and other financial measures should not be considered to be more meaningful than GAAP measures which are determined in accordance with IFRS, such as net income (loss), cash flow from (used in) operating activities, and cash flow from (used in) investing activities, as indicators of Rubellite's performance.

Non-GAAP Financial Measures

Capital Expenditures: Rubellite uses capital expenditures related to exploration and development to measure its capital investments compared to the Company's annual capital budgeted expenditures. Rubellite's capital budget excludes acquisition and disposition activities. Total capital expenditures includes exploration and development, land, geological and geophysical and corporate spending.

The most directly comparable GAAP measure for capital expenditures is cash flow used in investing activities. A summary of the reconciliation of cash flow used in investing activities to capital expenditures, is set forth below:

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands)	**2025**	2024	**2025**	2024
Net cash flows used in investing activities	**(32,754)**	(49,633)	**(115,058)**	(173,030)
Acquisitions	**—**	—	**—**	(62,732)
Dispositions	**2,291**	—	**7,791**	—
Change in non-cash working capital	**3,992**	(14,096)	**7,653**	(1,392)
Total capital expenditures	**(39,037)**	(35,537)	**(130,502)**	(108,906)
Property, plant and equipment additions	**(38,193)**	(32,565)	**(122,600)**	(90,680)
Exploration and evaluation additions	**(711)**	(2,844)	**(7,373)**	(15,129)
Corporate expenditures	**(133)**	(128)	**(529)**	(3,097)
Total capital expenditures	**(39,037)**	(35,537)	**(130,502)**	(108,906)
Add back:				
Corporate	**133**	128	**529**	3,097
Geological and geophysical	**3,770**	—	**4,947**	56
Land and other	**346**	1,011	**10,456**	4,021
Exploration and development spending[1]	**(34,788)**	(34,398)	**(114,570)**	(101,732)

(1) Non-GAAP supplementary measure. See "Supplementary Measures".

Cash costs: Cash costs are comprised of net operating costs, transportation, general and administrative, and cash finance expense as detailed below. Cash costs per boe is calculated by dividing cash costs by total production sold in the period. Management believes that cash costs assist management and investors in assessing Rubellite's efficiency and overall cost structure.

			Three months ended December 31,	
($ thousands, except per boe amounts)	***$/boe***	**2025**	*$/boe*	2024
Net operating costs	**5.80**	**6,957**	6.84	6,536
Transportation	**4.57**	**5,484**	6.01	5,747
General and administrative	**3.19**	**3,831**	3.69	3,522
Cash finance expense	**1.85**	**2,223**	2.91	2,784
Cash costs	**15.41**	**18,495**	19.45	18,589

			Twelve Months Ended December 31,	
($ thousands, except per boe amounts)	***$/boe***	**2025**	*$/boe*	2024
Net operating costs	**6.48**	**29,550**	7.11	16,514
Transportation	**5.18**	**23,623**	7.03	16,328
General and administrative	**3.48**	**15,875**	4.57	10,616
Cash finance expense	**2.10**	**9,589**	2.97	6,904
Cash costs	**17.24**	**78,637**	21.68	50,362

Operating netbacks and total operating netbacks, after risk management contracts: Operating netback is calculated by deducting royalties, net operating expenses, and transportation costs from oil and natural gas revenue. Operating netback is also calculated on a per boe basis using total production sold in the period. Total operating netbacks, after risk management contracts, is presented after adjusting for realized gains or losses from risk management contracts. Rubellite considers operating netback and operating netback after risk management contracts to be key industry performance indicators that provides investors with information that is also commonly presented by other oil and natural gas producers. Rubellite presents the operating netback at a CGU level as it provides investors with key information related to the Eastern Heavy Oil CGU which is the area where growth capital investment is focused. Operating netback and operating netback, after risk management contracts, evaluate operational performance as it demonstrates its profitability relative to realized and current commodity prices.

Net operating costs: Net operating costs equals operating expenses net of other income, which is made up of processing revenue and other one time items from time to time. Management views net operating costs as an important measure to evaluate its operational performance. The most directly comparable IFRS measure for net operating costs is production and operating expenses.

The following table reconciles net operating costs from production and operating expenses and other income in the Company's consolidated statement of income (loss) and comprehensive income (loss).

	Three months ended December 31,		Twelve months ended December 31,	
(*$ thousands, except per boe amounts*)	**2025**	2024	**2025**	2024
Other income	**247**	178	**827**	178
Less: Non processing income	**(88)**	—	**(431)**	—
Processing income	**159**	178	**396**	178
Production and operating	**7,116**	6,714	**29,946**	16,692
Less: processing income	**(159)**	(178)	**(396)**	(178)
Net operating costs	**6,957**	6,536	**29,550**	16,514
$/boe	**5.80**	6.84	**6.48**	7.11

Refer to reconciliations in the MD&A under the "Operating Netbacks" section for current period and comparative information.

Net Debt and Adjusted Working Capital Deficit: Rubellite uses net debt as an alternative measure of outstanding debt and is calculated by adding borrowings under the credit facility and term loan debt less adjusted working capital. Adjusted working capital is calculated by adding cash, accounts receivable, prepaid expenses and deposits and product inventory less accounts payable and accrued liabilities. Management considers net debt as an important measure in assessing the liquidity of the Company. Net debt is used by management to assess the Company's overall debt position and borrowing capacity. Net debt is not a standardized measure and therefore may not be comparable to similar measures presented by other entities.

The following table reconciles working capital and net debt as reported in the Company's statements of financial position:

(*$ thousands*)	**As of December 31, 2025**	As of December 31, 2024
Current assets	**35,181**	44,714
Current liabilities	**(70,413)**	(74,680)
Working capital deficit	**35,232**	29,966
Risk management contracts – current asset	**5,828**	9,783
Risk management contracts – current liability	**(327)**	(2,765)
Lease liability - current liability	**(389)**	(357)
Share based compensation liability - current liability	**(4,694)**	(5,357)
Decommissioning obligations – current liability	**(1,340)**	(2,000)
Other provision - current liability	**(3,750)**	(3,750)
Adjusted working capital deficit(1)	**30,560**	25,520
Bank indebtedness	**92,583**	108,500
Term loan (principal)	**20,000**	20,000
Net debt(2)	**143,143**	154,020

(1) Calculation of current assets less current liabilities has been adjusted for the removal of the current portion of risk management contracts, decommissioning liabilities, lease liabilities, share based compensation and other provisions.
(2) Excludes other non-current liabilities.

Adjusted funds flow: Adjusted funds flow is calculated based on net cash flows from operating activities, excluding changes in non-cash working capital and expenditures on decommissioning obligations, other provisions and cash-settled share based compensation since the Company believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning and share based compensation obligations may vary from period to period and are managed as expenditures through the corporate budgeting process which considers available adjusted funds flow. Management uses adjusted funds flow and adjusted funds flow per boe as key measures to assess the ability of the Company to generate the funds necessary to finance capital expenditures, expenditures on decommissioning obligations, expenditures on share based compensation and meet its financial obligations.

Adjusted funds flow is not intended to represent net cash flows from operating activities calculated in accordance with IFRS.

The following table reconciles net cash flows from operating activities, as reported in the Company's statements of cash flows, to adjusted funds flow:

	Three months ended December 31,		Twelve months ended December 31,	
(*$ thousands, except as noted*)	**2025**	2024	**2025**	2024
Net cash flows from operating activities	**30,900**	39,402	**128,796**	95,788
Change in non-cash working capital	**1,210**	(8,582)	**4,562**	(3,093)
Cash-settled share based compensation	**578**	631	**3,202**	631
Other provision settled	**—**	—	**3,750**	**—**
Non-cash portion of other income	**(88)**	—	**(88)**	—
Decommissioning obligations settled	**565**	181	**1,851**	451
Adjusted funds flow	**33,165**	31,632	**142,073**	93,777
Transaction costs	**—**	4,223	**—**	6,233
Adjusted funds flow, before transaction costs	**33,165**	35,855	**142,073**	100,010
Adjusted funds flow per share - basic	**0.35**	0.36	**1.52**	1.37
Adjusted funds flow per share - diluted	**0.34**	0.36	**1.48**	1.35
Adjusted funds flow per boe	**27.64**	33.10	**31.15**	40.35
Adjusted funds flow per share - before transaction costs - basic	**0.35**	0.41	**1.52**	1.46
Adjusted funds flow per share - before transaction costs - diluted	**0.34**	0.40	**1.48**	1.43
Adjusted funds flow per boe - before transaction costs	**27.64**	44.09	**31.15**	43.04

Free funds flow: Free funds flow is an important measure that informs efficiency of capital spent and liquidity. Free funds flow is calculated as adjusted funds flow generated during the period less capital expenditures, excluding non-cash items and acquisitions and dispositions. Adjusted funds flow and capital expenditures are non-GAAP financial measures which have been reconciled to its most directly comparable GAAP measure previously in this document. By comparing current period capital expenditures relative to adjusted funds flow, Rubellite monitors its free funds flow to inform decisions such as capital allocation, debt repayment and liquidity.

The following table shows the calculation of the removal of capital expenditures from adjusted funds flow:

	Three months ended December 31,		Twelve months ended December 31,	
(*$ thousands*)	**2025**	2024	**2025**	2024
Adjusted funds flow	**33,165**	31,632	**142,073**	93,777
Total capital expenditures	**(39,037)**	(35,537)	**(130,502)**	(108,906)
Free funds flow	**(5,872)**	(3,905)	**11,571**	(15,129)

Available Liquidity: Available liquidity is defined as the borrowing limit under the Company's credit facility, plus any cash and cash equivalents, less any borrowings and letters of credit issued under the credit facility. Management uses available liquidity to assess the ability of the Company to finance capital expenditures, expenditures on decommissioning obligations and to meet its financial obligations.

Enterprise value: Enterprise value is equal to net debt plus the market value of issued equity, and is used by management to analyze leverage. Enterprise value is calculated by multiplying the current shares outstanding by the market price at the end of the period and then adjusting it by the net debt. The Company considers enterprise value as an important measure as it normalizes the market value of the Company's shares for its capital structure.

Non-GAAP Financial Ratios

Rubellite calculates certain non-GAAP measures per boe as the measure divided by weighted average daily production. Management believes that per boe ratios are a key industry performance measure of operational efficiency and one that provides investors with information that is also commonly presented by other crude oil and natural gas producers. Rubellite also calculates certain non-GAAP measures per share as the measure divided by outstanding common shares, weighted average common shares or diluted weighted average common shares.

Average realized prices after risk management contracts: calculated as the average realized price by product type less the realized gain or loss on risk management contracts by product type.

Net debt to adjusted funds flow ratio: calculated on a trailing twelve-month basis.

Net debt to annualized adjusted funds flow ratio: calculated by annualizing the current quarter adjusted funds flow after transaction costs.

Net debt as a percentage of enterprise value: calculated by dividing net debt by enterprise value.

Adjusted funds flow per share: calculated on a per share as the measure divided by basic shares outstanding.

Adjusted funds flow per boe: calculated as adjusted funds flow divided by total production sold in the period.

Supplementary Financial Measures

"Exploration and development spending" is comprised of the non-GAAP measure total capital expenditures (as calculated above), less land and other, geological and geophysical and corporate spending.

"Average realized price" is comprised of total oil and natural gas revenue, as determined in accordance with IFRS, divided by the Company's total sales production on a per barrel basis.

"Realized oil price" is comprised of oil commodity sales from production, as determined in accordance with IFRS, divided by the Company's oil sales production.

"Realized natural gas price" is comprised of natural gas commodity sales from production, as determined in accordance with IFRS, divided by the Company's natural gas sales production.

"Realized NGL price" is comprised of NGL commodity sales from production, as determined in accordance with IFRS, divided by the Company's NGL sales production.

"Realized gain (loss) on natural gas contracts per Mcf" is comprised of the realized gain or loss on natural gas contracts, as determined in accordance with IFRS, divided by the Company's total natural gas sales production.

"Realized gain (loss) on oil contracts per boe" is comprised of the realized gain or loss on oil contracts, as determined in accordance with IFRS, divided by the Company's total oil sales production.

"Realized gain (loss) on risk management contracts per boe" is comprised of the realized gain or loss on risk management contracts, as determined in accordance with IFRS, divided by the Company's total sales production.

"Royalties as a percentage of revenue" is comprised of royalties, as determined in accordance with IFRS, divided by oil and natural gas revenue from sales production as determined in accordance with IFRS.

"Royalties per boe" is comprised of royalties, as determined in accordance with IFRS, divided by the Company's total sales production.

"Net operating expense per boe" is comprised of net operating expense, divided by the Company's total sales production.

"Transportation cost ($/boe)" is comprised of transportation cost, as determined in accordance with IFRS, divided by the Company's total sales production.

"G&A cost ($/boe)" is comprised of G&A expense, as determined in accordance with IFRS, divided by the Company's total sales production.

"Depletion and depreciation expense ($/boe)" is comprised of depletion expense, as determined in accordance with IFRS, divided by the Company's total sales production.

“Market value of shares” is comprised of common shares outstanding multiplied by the market price of shares.

“Heavy oil wellhead differential ($/bbl)” represents the differential the Company receives for selling its heavy crude oil production relative to the Western Canadian Select reference price (CAD$/bbl) prior to any price or risk management activities.

FUTURE ACCOUNTING PRONOUNCEMENTS

Future Accounting Pronouncements

In April 2024, the IASB issued IFRS 18 *Presentation and Disclosure in Financial Statements* ("IFRS 18"), which will replace IAS 1 and includes requirements for all entities applying IFRS Accounting Standards for the presentation and disclosure of information in the financial statements. IFRS 18 will introduce new totals, subtotals and categories for income and expenses in the statement of income and comprehensive income, as well as requiring disclosure about management defined performance measures and additional requirements regarding the aggregation and disaggregation of certain information. It will be effective on January 1, 2027, with earlier adoption permitted and it must be adopted on a retrospective basis. Rubellite is currently evaluating the impact of this standard on its consolidated financial statements.

In May 2024, the IASB issued amendments to IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* relating to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. The amendments will be effective on January 1, 2026, and are not expected to have a material impact on the Company's consolidated financial statements.

RISK FACTORS

The Corporation is exposed to business risks that are inherent in the oil and gas industry, as well as those governed by the individual nature of Rubellite’s operations. Risks impacting the business which influence controls and management of the Corporation include, but are not limited to, the following:

- health and safety risks affecting personnel;
- drilling, exploration, development, geological, engineering and completion risks;
- the uncertainty of discovering commercial quantities of new reserves;
- commodity prices, interest rate and foreign exchange risks;
- access to capital;
- political and geopolitical risks;
- competition;
- cybersecurity risks;
- inflation and supply chain risks;
- risks relating to pandemics and wildfires; and
- changes to government regulations including royalty regimes, tax legislation and tariffs.

Rubellite manages these risks by:

- making safety the Company's top priority and maintaining strict environmental, safety and health practices;
- attracting and retaining a team of highly qualified and motivated professionals who have a vested interest in the success of the Corporation;
- prudent operation of oil and natural gas properties;
- employing risk management instruments and policies to manage exposure to volatility of commodity prices, interest rates and foreign exchange rates;
- maintaining financial flexibility;

- active participation with industry organizations to monitor and influence changes in government regulations and policies; and
- assessing risk and implementing mitigation measures on an ongoing basis through an evolving enterprise risk management framework.

A complete discussion of risk factors is included in the Corporation's 2025 Annual Information Form available on the Corporation's website at www.rubelliteenergy.com or on SEDAR+ at www.sedarplus.ca.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P"), as defined by National Instrument 52-109. The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting ("ICFR"), as defined by National Instrument 52-109, to provide reasonable assurance regarding the reliability of the Company's financial reporting and the preparation of financial statements for external purposes in accordance with IFRS Accounting Standards.

Disclosure controls and procedures

The DC&P have been designed to provide reasonable assurance that material information relating to Rubellite is made known to the CEO and CFO by others, and that information required to be disclosed by Rubellite in its annual filings, interim filing or other reports is filed or submitted by Rubellite under securities legislation.

Rubellite's CEO and CFO have concluded, based on their evaluation at December 31, 2025, the DC&P are designed and operating effectively to provide reasonable assurance that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure.

Management's annual report on internal controls over financial reporting

Management is responsible for establishing and maintaining adequate ICOFR, which is a process designed by, or under the supervision of, the CEO and CFO, and effected by the board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

Under the supervision and with the participation of management, including the CEO and CFO, an evaluation of the effectiveness of the internal controls over financial reporting was conducted as of December 31, 2025 based on criteria described in "Internal Control – Integrated Framework" issued in 2013 by the Committee of Sponsoring Organization of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2025, the internal controls over financial reporting were designed and operating effectively.

INTERNAL CONTROLS AND PROCEDURES

Evaluation of disclosure controls and procedures

There were no changes in the Company's DC&P or ICFR during the period beginning October 1, 2025 and ending on December 31, 2025 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR.

CEO and CFO certifications

Rubellite's CEO and CFO have filed with the Canadian securities regulators regarding the quality of Rubellite's public disclosures relating to its fiscal 2025 filings with the Canadian securities regulators.

CRITICAL ACCOUNTING JUDGEMENTS AND ESTIMATES

Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimates that differ materially from current estimates.

Rubellite's financial and operational results incorporate certain estimates including:

- estimated commodity sales from production at a specific reporting date for which actual revenues have not yet been received, including associated estimated credit losses;
- estimated royalty obligations, transportation, and operating expenses at a specific reporting date for which costs have been incurred but have not yet been settled;
- estimated capital spending on projects that are in progress;
- estimated depletion charges and deferred tax assets that are based on estimates of reserves that Rubellite expects to recover in the future;
- estimated future recoverable value of PP&E and E&E and any associated impairment charges or reversals;
- estimated fair values of financial instruments that are subject to fluctuation depending upon the underlying forward curves for commodity prices, foreign exchange rates and interest rates, as well as volatility curves, and the risk of non-performance;
- estimated value of ARO that is dependent upon estimates of future costs and timing of expenditures;
- estimated compensation expense under Rubellite's share based compensation plans including the PSUs awarded under the PSU Plans that are dependent on the final number of PSU awards that eventually vest based on a performance multiplier; and
- estimated fair values of assets acquired and liabilities assumed in a business combination.

RESERVE DATA

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only and there is no guarantee that the estimated reserves will be recovered. In general, estimates of economically recoverable crude oil, natural gas and NGL reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For those reasons, estimates of the economically recoverable crude oil, NGL and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

All evaluations and reviews of future net revenue are stated prior to any provisions for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. The after-tax net present value of the Company's oil and gas properties reflects the tax burden on the properties on a stand-alone basis and utilizes the Company's tax pools. It does not consider the corporate tax situation, or tax planning. It does not provide an estimate of the after-tax value of the Company, which may be significantly different. The Company's financial statements and the MD&A should be consulted for information at the level of the Company.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to effects of aggregations. The estimated values of future net revenue disclosed in this MD&A do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

The reserve data provided in this MD&A presents only a portion of the disclosure required under NI 51-101. All of the required information will be contained in the AIF, which will be filed on SEDAR+ (accessible at www.sedarplus.ca) on or before March 31, 2026.

OIL AND GAS RESERVE DEFINITIONS

Reserves: are estimated remaining quantities of crude oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of capital assumptions, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates as follows.

Proved Reserves: are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable Reserves: are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the estimated proved plus probable reserves.

FORWARD-LOOKING INFORMATION

Certain information in this MD&A including management's assessment of future plans and operations, and including the information contained under the headings "Operations Update" and “Outlook and Guidance” may constitute forward-looking information or statements (together "forward-looking information") under applicable securities laws. The forward-looking information includes, without limitation, statements with respect to: future capital expenditures, production and various cost forecasts; the anticipated sources of funds to be used for capital spending; expectations as to future exploration, development and drilling activity, and the benefits to be derived from such drilling including drilling techniques, pilot projects and production growth; the plan to advance strategic initiatives including multiple enhanced oil recovery pilots, exploration activities, new land capture, capital spending activities in the Company's core properties at Figure Lake, Frog Lake and East Edson, anticipated average heavy oil sales volumes and total production sales volumes in the first quarter of 2026; the expectation that capital spending activity will be funded from adjusted funds flow, with excess free funds flow to reduce net debt and for other balance sheet obligations; operating and transportation cost forecasts for the first quarter of 2026; the expectation that blending demand for Clearwater and Mannville Stack heavy oil will continue to translate into attractive offsets to WCS benchmark pricing, planned ARO spending; Rubellite's business plan; the anticipated timing for providing full year guidance with the issuance of its Q1 2026 results in May; and including the forward-looking information contained under the heading "About Rubellite".

Forward-looking information is based on current expectations, estimates and projections that involve a number of known and unknown risks, which could cause actual results to vary and in some instances to differ materially from those anticipated by Rubellite and described in the forward-looking information contained in this MD&A. In particular and without limitation of the foregoing, material factors or assumptions on which the forward-looking information in this MD&A is based include: the successful operation of the Company's assets, forecast commodity prices and other pricing assumptions; forecast production volumes based on business and market conditions; foreign exchange and interest rates; near-term pricing and continued volatility of the market; accounting estimates and judgments; future use and development of technology and associated expected future results; the ability to obtain regulatory approvals; the successful and timely implementation of capital projects; ability to generate sufficient cash flow to meet current and future obligations and future capital funding requirements (equity or debt); the ability of Rubellite to obtain and retain qualified staff and equipment in a timely and cost-efficient manner, as applicable; the retention of key properties; forecast inflation, supply chain access and other assumptions inherent in Rubellite's current guidance and estimates; climate change; severe weather events (including wildfires, floods and drought); the continuance of existing tax, royalty, and regulatory regimes; the accuracy of the estimates of reserves volumes; ability to access and implement technology necessary to efficiently and effectively operate assets; risk of wars or other hostilities or geopolitical events (including the ongoing war in Ukraine and conflicts in the Middle East, South America and elsewhere), civil insurrection and pandemics; risks relating to Indigenous land claims and duty to consult; data breaches and cyber attacks; risks relating to the use of artificial intelligence; changes in laws and regulations, including but not limited to tax laws, royalties and environmental regulations (including greenhouse gas emission reduction requirements and other decarbonization or social policies) and including uncertainty with respect to the interpretation and impact of omnibus Bill C-59 and the related amendments to the Competition Act (Canada), and the interpretation of such changes to the Company's business); political, geopolitical and economic instability; trade policy, barriers, disputes or wars (including new tariffs or changes to existing international trade requirements) and general economic and business conditions and markets, among others.

Undue reliance should not be placed on forward-looking information, which is not a guarantee of performance and is subject to a number of risks or uncertainties, including without limitation those described herein and under "Risk Factors" in the Company's Annual Information Form and MD&A for the year ended December 31, 2024 (and once filed under "Risk Factors" in Rubellite's Annual Information Form and MD&A for the year ended December 31, 2025) and in other reports on file with Canadian securities regulatory authorities which may be accessed through the SEDAR+ website www.sedarplus.ca and at Rubellite's website www.rubelliteenergy.com. Readers are cautioned that the foregoing list of risk factors is not exhaustive. Forward-looking information is based on the estimates and opinions of Rubellite’s management at the time the information is released, and Rubellite disclaims any intent or obligation to update publicly any such forward-looking information, whether as a result of new information, future events or otherwise, other than as expressly required by applicable securities law.

ABBREVIATIONS AND CONVENTIONS

The following is a list of abbreviations that may be used in this MD&A:

Measurement:

bbl	barrel
bbl/d	barrels per day
Mbbl	thousand barrels
MMbbl	million barrels
boe	barrels of oil equivalent
Mboe	thousand barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
GJ	gigajoule

Industry Metrics:

This MD&A contains certain industry metrics which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this document to provide readers with additional measures to evaluate Rubellite's performance; however, such measures are not reliable indicators of Rubellite's future performance and future performance may not compare to Rubellite's performance in previous periods and therefore such metrics should not be unduly relied upon.

References to natural gas, crude oil and condensate and NGLs production in the MD&A refer to conventional natural gas, heavy crude oil and natural gas liquids, respectively, product types as defined in National Instrument 51-101.

Volume Conversions:

Barrel of oil equivalent ("boe") may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), a conversion ratio for conventional natural gas of 6 Mcf:1 bbl has been used, which 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 addition, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indicator of value as the value ratio between conventional natural gas and heavy crude oil, based on the current prices of natural gas and crude oil, differ significantly from the energy equivalency of 6 Mcf:1 bbl. A conversion ratio of 1 bbl of heavy crude oil to 1 bbl of NGL has also been used throughout this MD&A.

Initial Production Rates:

Any references in this MD&A to initial production rates are useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter and are not necessarily indicative of long-term performance or ultimate recovery. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. Such rates are based on field estimates and may be based on limited data available at this time.

Financial and Business Environment:

AECO	Alberta Energy Company
E&E	Exploration and evaluation
ESG	Environmental, social and governance
GAAP	Generally accepted accounting principles
G&A	General and administrative
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
NGL	Natural gas liquids
PP&E	Property, plant and equipment
WTI	West Texas Intermediate
WCS	Western Canadian Select

ANNUAL HISTORICAL FINANCIAL AND OPERATING HIGHLIGHTS

($ thousands, except as noted)	**2025**	2024	2023	2022
Financial				
Oil and natural gas revenue	**241,700**	168,384	88,968	54,491
Net income	**32,557**	49,973	18,561	24,605
Per share – basic(3)	**0.35**	0.73	0.31	0.47
Per share – diluted(3)	**0.34**	0.72	0.30	0.47
Total Assets	**578,509**	562,612	271,153	204,030
Cash flow from operating activities	**128,796**	95,788	55,391	23,870
Adjusted funds flow, after transaction costs(1)(6)	**142,073**	93,777	54,154	23,036
Per share – basic(2)(3)	**1.52**	1.37	0.90	0.44
Per share – diluted(2)(3)	**1.48**	1.35	0.89	0.44
Adjusted funds flow, before transaction costs(1)(6)	**142,073**	100,010	54,304	23,036
Per share – basic(2)(3)	**1.52**	1.46	0.90	0.44
Per share – diluted(2)(3)	**1.48**	1.43	0.89	0.44
Capital expenditures(1)				
Total capital expenditures(1)	**130,502**	108,906	71,530	94,207
Acquisitions(7)(8)	**—**	179,247	33,173	—
Dispositions(9)(10)	**—**	—	(7,990)	—
Total capital expenditures, after acquisitions and dispositions	**130,502**	288,153	96,713	94,207
Common shares (thousands)				
Weighted average – basic	**93,283**	68,667	60,346	52,093
Weighted average – diluted	**96,036**	69,716	61,075	52,471
Sales Production				
Heavy oil (bbl/d)(4)	**8,402**	5,685	3,302	1,670
Natural gas (Mcf/d)	**22,361**	3,570	—	—
NGL (bbl/d)(5)	**365**	69	—	—
Daily average sales production (boe/d)	**12,494**	6,349	3,302	1,670
Rubellite average realized prices(2)(11)				
Oil ($/bbl)	**71.38**	78.92	—	—
Natural gas ($/Mcf)	**1.84**	2.01	—	—
NGL ($/bbl)	**58.18**	61.32	—	—
Total average realized price ($/boe)	**53.00**	72.46	73.82	89.38

(1) Non-GAAP measure. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A for an explanation of composition.
(2) Non-GAAP ratio. Refer to the section entitled "Non-GAAP and Other Financial Measures" contained within this MD&A for an explanation of composition.
(3) Per share amounts are calculated using the weighted average number of basic or diluted common shares.
(4) Heavy oil sales production excludes tank inventory volumes.
(5) Liquids means oil, condensate, ethane, propane and butane.
(6) 2024 includes $6.2 million in transaction costs related to the BMEC Acquisition and the Recombination Transaction with Perpetual. 2023 includes $0.1 million in transaction costs related to a Clearwater Asset Acquisition.
(7) The Recombination Transaction closed on October 31, 2024 for share consideration of $51.7 million. The BMEC Acquisition closed on August 2, 2024 for total consideration of $73.1 million.
(8) Clearwater acquisition closing on November 8, 2023 for cash consideration of $34.0 million, prior to purchase price adjustments.
(9) Royalty sale closed on December 8, 2023 for cash consideration of $8.0 million, prior to purchase price adjustments.
(10) In 2025, the Company disposed of non-producing acreage for cash consideration of $7.8 million with a net book value of nil, resulting in a gain on disposition of assets of $7.8 million reported in the Company's statement of income and other comprehensive income.
(11) Before risk management contracts; supplementary financial measure. See "Non-GAAP and Other Financial Measures".

SUMMARY OF QUARTERLY RESULTS

($ thousands, except as noted)	**Q4 2025**	**Q3 2025**	**Q2 2025**	**Q1 2025**
Financial				
Oil and natural gas revenue	**56,261**	58,290	60,542	66,607
Net income (loss) and comprehensive income (loss)	**9,700**	5,646	16,051	1,160
Per share – basic(2)	**0.10**	0.06	0.17	0.01
Per share – diluted(2)	**0.10**	0.06	0.17	0.01
Total assets	**578,509**	558,709	561,545	551,889
Cash flow from operating activities	**30,900**	34,953	35,808	27,135
Adjusted funds flow, after transaction costs(1)(5)	**33,165**	35,663	37,311	35,934
Per share – basic(1)(2)	**0.35**	0.38	0.40	0.39
Per share – diluted(1)(2)	**0.34**	0.37	0.39	0.38
Total capital expenditures(1)(6)	**39,037**	35,365	31,168	24,932
Common shares (thousands)				
Weighted average – basic	**94,488**	93,700	93,279	92,930
Weighted average – diluted	**97,478**	96,311	95,074	95,068
Sales Production				
Heavy oil (bbl/d)(4)	**8,295**	8,338	8,637	8,339
Natural gas (Mcf/d)	**25,884**	20,975	20,522	22,038
NGL (bbl/d)(5)	**433**	288	368	371
Daily average sales production (boe/d)	**13,042**	12,122	12,425	12,383
Rubellite average realized price(1)				
Oil ($/bbl)	**63.32**	72.40	69.98	80.03
Natural gas ($/Mcf)	**2.47**	0.66	1.93	2.16
NGL ($/bbl)	**51.93**	56.12	57.92	67.54
Total average realized price ($/boe)	**46.89**	52.27	53.54	59.77

($ thousands, except as noted)	**Q4 2024**	**Q3 2024**	**Q2 2024**	**Q1 2024**
Financial				
Oil and natural gas revenue	59,081	43,682	35,798	29,823
Net income (loss) and comprehensive income (loss)	26,747	15,010	12,368	(4,153)
Per share – basic(2)	0.31	0.23	0.20	(0.07)
Per share – diluted(2)	0.30	0.23	0.19	(0.07)
Total assets	562,612	432,836	281,549	267,298
Cash flow from operating activities	39,402	19,973	19,916	16,497
Adjusted funds flow, after transaction costs(1)(5)	31,632	23,029	20,664	18,452
Per share – basic(1)(2)	0.36	0.35	0.33	0.30
Per share – diluted(1)(2)	0.36	0.35	0.33	0.30
Total capital expenditures(1)	35,537	36,650	23,927	12,792
Acquisitions(3)	68,467	62,732	—	—
Common shares (thousands)				
Weighted average – basic	87,655	65,834	62,494	62,457
Weighted average – diluted	88,546	66,571	63,446	62,457
Production				
Heavy oil (bbl/d)(4)	7,754	5,954	4,503	4,514
Natural gas (Mcf/d)	14,140	—	—	—
NGL (bbl/d)(5)	275	—	—	—
Daily average sales production (boe/d)	10,386	5,954	4,503	4,514
Rubellite average realized price(1)				
Oil ($/bbl)	76.97	79.75	87.35	72.60
Natural gas ($/Mcf)	2.01	—	—	—
NGL ($/bbl)	61.32	—	—	—
Total average realized price ($/bbl)	61.83	79.75	87.35	72.60

(1) Non-GAAP measure, ratio or supplementary measure. See "Non-GAAP and Other Financial Measures".
(2) Per share amounts are calculated using the weighted average number of basic or diluted common shares.
(3) Includes cash and non-cash consideration.
(4) Heavy oil sales production excludes tank inventory volumes.
(5) Q4 2024 includes $4.2 million in transaction costs related to the Recombination Transaction with Perpetual, Q3 2024 includes $2.0 million in transaction costs related to the BMEC Acquisition.
(6) In Q3 and Q4 2025, the Company disposed of non-producing acreage for cash consideration of $5.5 million and $2.3 million respectively, with a net book value of nil, resulting in a gain on disposition of assets of $7.8 million reported in the Company's statement of income and other comprehensive income.

Oil and natural gas revenue has ranged between $29.8 million and $66.6 million over the prior eight quarters largely due to increasing sales volumes from 4,503 boe/d to 13,042 boe/d, partially offset by volatility in commodity pricing. Net income (loss) has ranged between a loss of $4.2 million and income of $26.7 million primarily due to increased production, corporate acquisitions and dispositions, volatility of commodity prices and its impact on revenue, royalties and realized and unrealized risk management contract gains and losses and deferred income taxes.

MANAGEMENT'S REPORT

The consolidated financial statements of Rubellite Energy Corp. ("Rubellite" or the "Company") are the responsibility of Management and have been approved by the Board of Directors of the Company. These consolidated financial statements have been prepared by Management in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IASB").

The consolidated financial statements are audited and have been prepared using accounting policies in accordance with IFRS Accounting Standards. The preparation of Management's Discussion and Analysis is based on the Company's financial results which have been prepared in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IASB"). It examines the Company's financial performance in 2025 compared to 2024 and should be read in conjunction with the consolidated financial statements and accompanying notes.

Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Management believes that the system of internal controls that have been designed and maintained at the Company provide reasonable assurance that financial records are reliable and form a proper basis for preparation of the consolidated financial statements. The internal accounting control process includes Management's communication to employees of policies which govern ethical business conduct.

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 statement 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 the policies or procedures may deteriorate.

The Board of Directors has appointed an Audit Committee consisting of unrelated, non-management directors which meets during the year with Management and independently with the external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the charter of the Audit Committee as set out in the Annual Information Form. The Audit Committee reviews the consolidated financial statements and Management's Discussion and Analysis before the consolidated financial statements are submitted to the Board of Directors for approval. The external auditors have free access to the Audit Committee without obtaining prior Management approval.

With respect to the external auditors, the Audit Committee approves the terms of engagement and reviews the annual audit plan, the Auditor's Report and results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The independent external auditors, KPMG LLP, have been appointed by the Board of Directors on behalf of the shareholders to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's financial position, financial performance and cash flows in accordance with IFRS Accounting Standards. The report of KPMG LLP outlines the scope of their examination and their opinion on the consolidated financial statements.

Susan Riddell Rose

Susan L. Riddell Rose

President &
Chief Executive Officer

Ryan Shay

Ryan A. Shay

Vice President, Finance &
Chief Financial Officer

March 10, 2026

KPMG LLP
KPMG Tower 2200, 240 Fourth Ave SW
Calgary AB T2P 4H4
Canada
Tel 403 691 8000
Fax 403 691 8008

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Rubellite Energy Corp.

Opinion

We have audited the consolidated financial statements of Rubellite Energy Corp. (the Entity), which comprise:

- the consolidated statements of financial position as at December 31, 2025 and December 31, 2024
- the consolidated statements of income and comprehensive income for the years then ended
- the consolidated statements of changes in equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of material accounting policy information

(Hereinafter referred to as the "financial statements").

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

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the **"Auditor's Responsibilities for the Audit of the Financial Statements"** section of our auditor's report.

We are independent of the Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

KPMG

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended December 31, 2025. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

We have determined the matters described below to be the key audit matters to be communicated in our auditor's report.

Assessment of the impact of estimated proved and probable oil and gas reserves on property, plant and equipment ("PP&E")

Description of the matter

We draw attention to note 2, note 3, and note 4 to the financial statements. The Entity uses estimates of proved and probable oil and gas reserves to deplete its development and production assets included in PP&E, to assess for indicators of impairment on the Entity's cash generating units ("CGUs") and if any such indicators exist, to perform an impairment test to estimate the recoverable amount of the CGU, to assess exploration and evaluation ("E&E") costs for impairment when transferred to PP&E.

The Entity has $491.1 million of development and production assets as at December 31, 2025.

The Entity identified indicators of impairment as at December 31, 2025 for its West Central CGU and, as a result, completed an impairment test. The impairment test determined that the recoverable amount of the West Central CGU, determined using a value-in-use approach, exceeded its carrying value as at December 31, 2025 and as a result, no impairment was recognized.

The determination of the recoverable amount of the West Central CGU involves significant estimates and assumptions, including:

- The estimate of proved and probable oil and gas reserves
- The discount rates.

The Entity depletes its net carrying value of development and production assets using the unit-of-production method by reference to the ratio of production in the period to the related proved and probable oil and gas reserves, taking into account estimated forecasted future development costs necessary to bring those reserves into production. Depletion expense on development and production assets was $92.8 million for the year ended December 31, 2025.

The estimate of proved and probable oil and gas reserves includes significant assumptions related to:

- Forecasted oil and gas commodity prices
- Forecasted production
- Forecasted operating costs
- Forecasted royalty costs
- Forecasted future development costs.

The Entity engages independent third-party reserve evaluators to estimate proved and probable oil and gas reserves.

Why the matter is a key audit matter

We identified the assessment of the impact of estimated proved and probable oil and gas reserves on development and production assets included in PP&E as a key audit matter. Significant auditor judgment was required to evaluate the results of our audit procedures regarding the estimate of proved and probable oil and gas reserves and the discount rates. Additionally, the assessment of the recoverable amount of the West Central CGU requires the use of professionals with specialized skills and knowledge in valuation.

How the matter was addressed in the audit

The following are the primary procedures we performed to address this key audit matter:

We assessed the depletion expense and impairment test calculations for compliance with IFRS Accounting Standards as issued by the International Accounting Standards Board.

With respect to the estimate of proved and probable oil and gas reserves as at December 31, 2025:

- We evaluated the competence, capabilities and objectivity of the independent third-party reserve evaluators engaged by the Entity
- We compared forecasted oil and gas commodity prices to those published by other independent third-party reserve evaluators
- We compared the 2025 actual production, operating costs, royalty costs and development costs of the Entity to those estimates used in the prior year's estimate of proved oil and gas reserves to assess the Entity's ability to accurately forecast
- We evaluated the appropriateness of forecasted production and forecasted operating costs, royalty costs and future development costs assumptions by comparing to 2025 historical results. We took into account changes in conditions and events affecting the Entity to assess the adjustments or lack of adjustments in arriving at the assumptions.

  We involved valuation professionals with specialized skills and knowledge, who assisted in:

  - Evaluating the appropriateness of the West Central CGU discount rates by comparing the discount rate to market and other external data.
  - Assessing the reasonableness of the Entity's estimate of recoverable amount of the West Central CGU by comparing the Entity's estimates to market metrics and other external data.

Other Information

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

- the information included in Management's Discussion and Analysis.
- the information, other than the financial statements and the auditor's report thereon, included in a document likely to be entitled "2025 Annual Results".

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis as at the date of this auditor's report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditor's report.

We have nothing to report in this regard.

The information, other than the financial statements and the auditor's report thereon, included in a document likely to be entitled "2025 Annual Report" is expected to be made available to us after the date of this auditor's report. If, based on the work we will perform on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact to those charged with governance.

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

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

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

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

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Entity's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Entity's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Entity to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

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

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

- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within the group as a basis for forming an opinion on the group financial statements. We are responsible for the direction, supervision and review of the audit work performed for the purposes of the group audit. We remain solely responsible for our audit opinion.

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

KPMG

KPMG LLP

Chartered Professional Accountants

The engagement partner on the audit resulting in this auditor's report is Jasmeet Kang.

Calgary, Canada
March 10, 2026

RUBELLITE ENERGY CORP.
Consolidated Statements of Financial Position

As at	**December 31, 2025**	December 31, 2024
(*Cdn$ thousands*)		
Assets		
Current assets		
Cash	**$ —**	$ 2,555
Accounts receivable	**22,493**	26,349
Prepaid expenses, deposits and other	**2,999**	2,752
Product inventory	**3,861**	3,275
Risk management contracts (note 17)	**5,828**	9,783
	35,181	44,714
Property, plant and equipment (note 4)	**495,447**	461,996
Exploration and evaluation (note 5)	**31,054**	29,106
Right-of-use asset (note 6)	**4,447**	4,930
Deferred tax asset (note 14)	**12,380**	21,437
Risk management contracts (note 17)	**—**	429
Total assets	**$ 578,509**	$ 562,612
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 59,913**	$ 60,451
Risk management contracts (note 17)	**327**	2,765
Lease liabilities (note 7)	**389**	357
Share based compensation liability (note 10)	**4,694**	5,357
Decommissioning obligations (note 8a)	**1,340**	2,000
Other provision (note 8b)	**3,750**	3,750
	70,413	74,680
Bank debt (note 12)	**92,583**	108,500
Term loan (note 13)	**19,173**	19,027
Lease liabilities (note 7)	**4,340**	4,608
Risk management contracts (note 17)	**—**	225
Share based compensation liability (note 10)	**2,210**	914
Decommissioning obligations (note 8a)	**34,302**	29,817
Other provision (note 8b)	**11,554**	14,824
Total liabilities	**234,575**	252,595
Equity		
Share capital (note 9)	**207,673**	206,313
Contributed surplus	**2,863**	2,863
Retained earnings	**133,398**	100,841
Total equity	**343,934**	310,017
Total liabilities and equity	**$ 578,509**	$ 562,612

Commitments (note 19)

See accompanying notes to the consolidated financial statements.

Holly Benson
Director

Linda Dietsche
Director

RUBELLITE ENERGY CORP.
Consolidated Statements of Income and Comprehensive Income

		December 31, 2025		December 31, 2024
(Cdn$ thousands, except per share amounts)				
Revenue				
Oil and natural gas (note 11)	**$**	**241,700**	$	168,384
Royalties		**(32,454)**		(20,272)
		209,246		148,112
Realized gain on risk management contracts (note 17)		**11,371**		2,582
Unrealized loss on risk management contracts (note 17)		**(1,721)**		(12,252)
Other income		**827**		178
		219,723		138,620
Expenses				
Production and operating		**29,946**		16,692
Transportation		**23,623**		16,328
General and administrative		**15,875**		10,616
Share based payments (note 10)		**5,368**		3,571
Exploration and evaluation (note 5)		**5,543**		541
Gain on disposition (note 4c)		**(7,791)**		(31,617)
Depletion and depreciation (note 4, 6)		**94,243**		49,847
Transaction costs		**132**		6,233
		52,784		66,409
Finance expense (note 15)		**(11,343)**		(7,376)
Income before income tax		**41,441**		59,033
Taxes				
Deferred expense (note 14)		**(8,884)**		(9,060)
Net income and comprehensive income	**$**	**32,557**	$	49,973
Net income per share (note 9c)				
Basic	**$**	**0.35**	$	0.73
Diluted	**$**	**0.34**	$	0.72

See accompanying notes to the consolidated financial statements.

RUBELLITE ENERGY CORP.
Consolidated Statements of Changes in Equity

	Share Capital			Contributed		Retained		Total
	(thousands)	*($thousands)*		surplus		earnings		Equity
(Cdn$ thousands, except share amounts)								
Balance at December 31, 2024	92,877	$ 206,313	$	2,863	$	100,841	$	310,017
Net income	—	—		—		32,557		32,557
Common shares issued, net of issue costs (note 9)	—	(173)		—		—		(173)
Common shares issued, share based payment plan (note 10)	716	1,533		—		—		1,533
Balance at December 31, 2025	**93,593**	**$ 207,673**	**$**	**2,863**	**$**	**133,398**	**$**	**343,934**

	Share Capital			Share purchase		Contributed		Retained	Total
	(thousands)	*($thousands)*		warrants		surplus		earnings	Equity
(Cdn$ thousands, except share amounts)									
Balance at December 31, 2023	62,456	$ 143,033	$	2,000	$	3,410	$	50,868	$199,311
Net income	—	—		—		—		49,973	49,973
Common shares issued, net of issue costs (note 9)	30,192	61,713		—		—		—	61,713
Cancellation of share purchase warrants (note 9)	—	—		(2,000)		2,000		—	—
Reclassification of share based compensation liability (note 10)	—	—		—		(3,696)		—	(3,696)
Common shares issued, share based payment plan (note 10)	229	1,567		—		(2,140)		—	(573)
Share based payments (note 10)	—	—		—		3,289		—	3,289
Balance at December 31, 2024	92,877	$ 206,313	$	—	$	2,863	$	100,841	$310,017

See accompanying notes to the consolidated financial statements.

RUBELLITE ENERGY CORP.
Consolidated Statements of Cash Flows

	December 31, 2025	December 31, 2024
(*Cdn$ thousands*)		
Cash flows from operating activities		
Net income	**$ 32,557**	$ 49,973
Adjustments to add (deduct):		
Depletion and depreciation (note 4, 6)	**94,243**	49,847
Share based payments (note 10)	**5,368**	3,571
Deferred tax expense (note 14)	**8,884**	9,060
Unrealized loss on risk management contracts (note 17)	**1,721**	12,252
Non-cash finance expense (note 15)	**1,754**	472
Gain on dispositions (note 4c)	**(7,791)**	(31,617)
Non-cash exploration and evaluation expense (note 5)	**5,425**	220
Payment for share based compensation (note 10)	**(3,202)**	(632)
Payment for other provision (note 8b)	**(3,750)**	—
Decommissioning obligations settled (note 8a)	**(1,851)**	(451)
Change in non-cash working capital (note 16)	**(4,562)**	3,093
Net cash flows from operating activities	**128,796**	95,788
Cash flows from (used in) financing activities		
Common shares issues, net of fees	**—**	(624)
Term loan, net of issue costs (note 13)	**—**	18,964
Payment lease liabilities (note 7)	**(376)**	(71)
Repayment of acquired bank debt (note 4c)	**—**	(14,215)
Change in bank debt (note 12)	**(15,917)**	75,743
Net cash flows from (used in) financing activities	**(16,293)**	79,797
Cash flows used in investing activities		
Development and production expenditures (note 4)	**(122,600)**	(90,680)
Corporate expenditures (note 4)	**(529)**	(3,097)
Exploration and evaluation expenditures (note 5)	**(7,373)**	(15,129)
Acquisitions (note 4c)	**—**	(62,732)
Proceeds from dispositions (note 4c)	**7,791**	—
Change in non-cash working capital (note 16)	**7,653**	(1,392)
Net cash flows used in investing activities	**(115,058)**	(173,030)
Change in cash	**(2,555)**	2,555
Cash, beginning of year	**2,555**	—
Cash, end of year	**$ —**	$ 2,555

See accompanying notes to the consolidated financial statements.

1. REPORTING ENTITY

Rubellite Energy Corp. ("Rubellite" or the "Company") is an oil and natural gas exploration and production company headquartered in Calgary, Alberta.

The address of the Company's registered office is 3200, 605 – 5 Avenue S.W., Calgary, Alberta, T2P 3H5.

The consolidated financial statements presented for the years ended December 31, 2025 and 2024 represent the results of Rubellite Energy Corp. and its wholly owned subsidiaries Rubellite Energy Inc., Ukalta GP Inc., Ukalta Limited Partnership, Perpetual Energy Inc., Perpetual Operating Corp., Perpetual Energy Partnership and Perpetual Operating Trust. On January 1, 2025, the subsidiary Perpetual Energy Inc. was amalgamated with Rubellite Energy Inc..

2. BASIS OF PREPARATION

These consolidated financial statements have been prepared in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IASB").

These consolidated financial statements have been prepared on a historical cost basis, except as otherwise noted within these financial statements. These consolidated financial statements are presented in Canadian dollars which is also the Company's functional currency.

These consolidated financial statements of the Company were approved and authorized for issue by the Board of Directors on March 10, 2026.

a) Critical accounting judgements and significant estimates

The preparation of the consolidated financial statements in conformity with IFRS Accounting Standards requires management to make judgements, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenue and expenses. These judgements, estimates, and assumptions are continuously evaluated and are based on management's experience and all relevant information available to the Company at the time of consolidated financial statements preparation. As the effect of future events cannot be determined with certainty, the actual results may differ from estimates. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

b) Critical accounting judgements

The following are the critical judgements that management has made in the process of applying the Company's accounting policies. These judgements have the most significant effect on the amounts reported in the consolidated financial statements.

i) Cash-generating units ("CGUs")

The Company allocates its development and production assets to CGUs, identified as the smallest group of assets that generate cash inflows independent of the cash inflows of other assets or groups of assets. Determination of the CGUs is subject to management's judgement and is based on geographical proximity, shared infrastructure, and similar exposure to market risk. The Company operates as a single operating segment.

ii) Identification of impairment indicators

Significant judgement is required to assess when internal or external indicators of impairment or impairment reversal exist, and impairment testing is required. Management considers internal and external sources of information including oil and gas commodity prices, expected production volumes, anticipated recoverable quantities of proved and probable oil and gas reserves and rates used to discount the related future cash flow estimates. Judgement is required to assess these factors when determining if the carrying amount of an asset or CGU is impaired, or in the case of a previously impaired asset or CGU, whether the carrying amount of the asset or CGU has been restored.

iii) Exploration and evaluation ("E&E") expenditures

Costs associated with acquiring oil and gas licenses and exploratory drilling are accumulated as exploration and evaluation assets pending determination of technical feasibility and commercial viability. Establishment of technical feasibility and commercial viability is subject to judgement and involves management's review of project economics, resource quantities, expected production techniques, production costs and required capital expenditures to develop and extract the underlying resources. Management uses the establishment of commercial reserves within the exploration area as the basis for determining technical feasibility and commercial viability. Upon determination of commercial reserves, E&E assets attributable to those reserves are reclassified from E&E assets to a separate category within property, plant and equipment referred to as development and production assets and are tested for impairment.

iv) Joint arrangements

Judgement is required to determine when the Company has joint control over an arrangement. In establishing joint control, the Company considers whether unanimous consent is required to direct the activities that significantly affect the returns of the arrangement, such as the capital and operating activities of the arrangement.

Once joint control has been established, judgement is also required to classify a joint arrangement. The type of joint arrangement is determined through analysis of the rights and obligations arising from the arrangement by considering its structure, legal form, and terms agreed upon by the parties sharing control. An arrangement where the controlling parties have rights to the assets and revenues, and obligations for the liabilities and expenses, is classified as a joint operation. Arrangements where the controlling parties have rights to the net assets of the arrangement are classified as joint ventures.

v) Deferred taxes

Deferred tax assets are recognized only to the extent it is considered probable that future taxable profits will be sufficient to utilize the underlying deductible temporary differences and unused tax losses associated with the deferred tax asset. This involves an assessment of when those deferred tax assets are likely to reverse and judgement as to whether there will be sufficient taxable profits available to offset the tax assets when they do reverse. The determination of probable future taxable profits involves significant estimates, including proved and probable oil and gas reserves. To the extent 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 amounts recognized within the consolidated statements of income and comprehensive income in the period in which the change occurs.

vi) Business combinations

Judgement is required to determine whether an acquisition constitutes a business, for determining the accounting acquirer and the acquisition date for accounting purposes and then to determine the fair value of acquired entity.

c) Significant estimates

The following assumptions represent the key sources of estimation uncertainty at the end of the reporting period. As future confirming events occur, the actual results may differ from estimated amounts.

i) Reserves

The Company uses estimates of proved and probable oil and gas reserves to deplete its development and production assets included in PP&E, to assess for indicators of impairment on the Company's CGU and if any such indicators exist, to perform an impairment test to estimate the recoverable amount of the CGU, to fair value oil and natural gas assets acquired in a business combination, to assess E&E costs for impairment when transferred to PP&E and to determine if it is probable that future taxable profits will be sufficient to utilize the underlying deductible temporary differences and unused tax losses associated with the deferred tax asset. Estimates of proved and probable oil and gas reserves and their related cash flows are based upon a number of significant assumptions, such as forecasted production, oil and gas commodity prices, operating costs, royalty costs and future development costs. Additional estimates are made in relation to the marketability of oil and gas, and the assumed effects of regulation by government agencies and the potential imposition of tariffs. The geological, economic and technical factors used to estimate reserves may change from period to period. Changes in the reported reserves could have a material impact on the carrying values of the Company’s development and production assets, the calculation of depletion and depreciation, and the timing of decommissioning expenditures.

Independent third-party reserve evaluators are engaged at least annually to estimate proved and probable oil and gas reserves and the related cash flows from the Company’s interest in development and production assets. This evaluation of proved and proved plus probable oil and gas reserves is prepared in accordance with the reserve definitions contained in National Instrument 51-101 and the Canadian Oil and Gas Evaluation "COGE" Handbook. The Company obtained an annual evaluation from its independent third-party reserve evaluators to estimate proved and probable oil and gas reserves and the related cash flows on December 31, 2025.

ii) Business combinations

The determination of the acquisition-date fair value of oil and gas interests acquired through a business combination involves significant estimates and assumptions, including the cash flows associated with the proved and probable oil and gas reserves and the discount rates.

iii) Provisions for decommissioning obligations

Decommissioning, abandonment, and site reclamation expenditures for production facilities, wells, and pipelines are expected to be incurred by the Company over many years into the future. Amounts recorded for decommissioning obligations and the associated accretion are calculated based on estimates of the extent and timing of decommissioning activities, future site remediation regulations and technologies, inflation, liability specific discount rates and related cash flows. The provision represents management’s best estimate of the present value of the future abandonment and reclamation costs required. Actual abandonment and reclamation costs could be materially different from estimated amounts.

iv) Derivative financial instruments

Derivatives are measured at fair value on each reporting date. Fair value is the price that would be received or paid to exit the position as of the measurement date. The Company uses estimated external forecasted market price curves available at period end and the contracted volumes over the contracted term to determine the fair value of each contract. Changes in market pricing between period end and settlement of the derivative contracts could have a material impact on financial results related to the derivatives.

v) Share based payments

Share options, deferred options and long-term incentive awards issued by the Company are recorded at fair value using the Black Scholes option pricing model. In assessing the fair value of share options, estimates have to be made regarding the expected volatility in share price, option life, dividend yield, risk-free rate and estimated forfeitures at the initial grant date.

The estimate of share based compensation expense related to the Company's Performance Share Units ("PSUs") is dependent on management's estimate of the period end performance multiplier.

3. MATERIAL ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently in these consolidated financial statements.

a) Basis of Consolidation

a) Subsidiaries

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that are currently exercisable are considered. The consolidated financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

b) Transactions eliminated on consolidation

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

c) Jointly owned assets

Many of the Company's oil and gas activities involve jointly owned assets which are not conducted through a separate entity. The consolidated financial statements include the Company's proportionate share of these jointly owned assets, liabilities, revenues and expenses.

b) Business combinations

The acquisition method of accounting is used to account for acquisitions of businesses and assets that meet the definition of a business under IFRS 3. The cost of an acquisition is measured as the fair value of the assets given up, equity instruments issued and liabilities incurred or assumed at the acquisition date. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their acquisition date fair values with the exception of income taxes, right-of-use assets and lease liabilities. Any excess of the consideration paid greater than the fair value of the net assets received is recognized as goodwill on the consolidated statement of financial position. Any deficiency in the consideration transferred compared to the fair value of the net assets acquired is recognized in the consolidated statement of income. Any deferred tax asset or liability arising from a business combination is recognized at the acquisition date. Pre-existing relationships settled through a business combination are deemed to be settled immediately prior to acquisition date. Acquisition costs incurred are expensed through the consolidated statement of income and results of acquisitions are included in the consolidated financial statements from the closing date of the acquisition.

c) Financial instruments

Financial instruments comprise cash and cash equivalents, marketable securities, accounts receivable, deposits, accounts payable and accrued liabilities, fair value of risk management contract assets and liabilities, term loan and bank debt. These financial instruments are recognized initially at fair value, net of any directly attributable transaction costs.

i) Classification and measurement of financial assets

A financial asset is measured at amortized cost if it meets both of the following conditions and is not designated at fair value through profit or loss (“FVTPL”):

– it is held within a business model whose objective is to hold assets to collect contractual cash flows; and
– it's contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

A debt investment is measured at fair value through other comprehensive income (“FVOCI”) if it meets both of the following conditions and is not designated at FVTPL:

– it is held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets; and
– its contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

All financial assets not classified as measured at amortized cost or FVOCI as described above are measured at FVTPL. On initial recognition, the Company may irrevocably designate a financial asset that otherwise meets the requirements to be measured at amortized cost or at FVOCI at FVTPL if doing so eliminates or significantly reduces an accounting mismatch that would otherwise arise.

The following accounting policies apply to the subsequent measurement of financial assets:

a) Financial assets at FVTPL

These assets are subsequently measured at fair value. Net gains and losses, including any interest or dividend income, are recognized in profit or loss.

b) Financial assets amortized cost

These assets are subsequently measured at amortized cost using the effective interest method. The amortized cost is reduced by impairment losses. Interest income, foreign exchange gains and losses and impairment are recognized in profit or loss. Any gain or loss on derecognition is recognized in profit or loss.

ii) Classification and measurement of financial liabilities

Financial liabilities are classified and measured at amortized cost or FVTPL. A financial liability is classified at FVTPL if it is a derivative or it is designated as such on initial recognition. Financial liabilities at FVTPL are measured at fair value and net gains and losses, including any interest expense, are recognized in profit or loss. Other financial liabilities are subsequently measured at amortized cost using the effective interest method. Interest expense and foreign exchange gains and losses are recognized in profit or loss. Any gain or loss on derecognition is also recognized in profit or loss.

The Company has classified cash, accounts receivable, deposits, accounts payable and accrued liabilities, term loan and bank debt as amortized cost. The marketable securities have been classified as FVTPL.

iii) Derivative assets and liabilities

The Company has entered into certain financial derivative contracts to manage the exposure to market risks from fluctuations in commodity prices. The Company has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting. All financial derivative contracts are designated as FVTPL and recorded as derivatives on the consolidated statement of financial position at fair value. Changes in the fair value of the derivatives are recognized in the consolidated statements of income and comprehensive income.

d) Property, plant and equipment ("PP&E")

i) Development and production costs

Items of property, plant and equipment, which include development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. The initial cost of property, plant and equipment includes the purchase price or construction costs, costs that are directly attributable to bringing the asset into commercial operations, and the initial estimate of decommissioning costs.

Gains and losses on disposition of an item of property, plant and equipment, including development and production assets, are determined by comparing the proceeds from disposition with the carrying amount of property, plant and equipment and are recognized within the consolidated statements of income and comprehensive income. Proceeds may include cash, or other non-cash consideration such as retained drilling rights which are fair valued at the time of disposition. The carrying amount of any replaced or disposed item of property, plant and equipment is derecognized.

ii) Subsequent costs

Costs incurred after the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as property, plant and equipment only when they increase the future economic benefits embodied in the specific asset to which they relate. Such capitalized property, plant and equipment generally represent costs incurred in developing proved and/or probable oil and gas reserves and bringing on or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. All other expenditures including the costs of the day-to-day servicing of property, plant and equipment are recognized as production and operating expense in the consolidated statements of income and comprehensive income as incurred.

iii) Depletion and depreciation

The Company depletes its net carrying value of development and production assets using the unit-of-production method by reference to the ratio of production in the period to the related proved and probable oil and gas reserves, taking into account estimated forecasted future development costs necessary to bring those reserves into production. The forecasted future development cost estimates are reviewed by independent third-party reserve evaluators at least annually.

Depreciation methods, useful lives and residual values are reviewed at each period end date for all classes of property, plant, and equipment.

Capital expenditures are not depreciated or depleted until assets are substantially complete and are ready for their intended use.

e) Exploration and evaluation (E&E)

Pre-license costs, geological and geophysical costs, and lease rentals of undeveloped properties are recognized within the consolidated statements of income and comprehensive income as incurred.

E&E costs, consisting of the costs of acquiring oil and gas licenses, are capitalized initially as E&E assets according to the nature of the assets acquired. Costs associated with drilling exploratory wells in an undeveloped area are capitalized as E&E costs. The costs are accumulated in cost centers by well, field or exploration area pending determination of technical feasibility and commercial viability. When technical feasibility and commercial viability are determined, the relevant expenditure is transferred to property, plant and equipment as development and production assets, after impairment is assessed and any applicable impairment loss is recognized within the consolidated statement of income and comprehensive income.

The Company's E&E assets consist of undeveloped land, drilling, completions and other facility expenditures. Gains and losses on disposition of E&E assets are determined by comparing the proceeds from disposition with the carrying amount and are recognized within the consolidated statements of income and comprehensive income.

f) Right-of-use assets

The Company recognizes right-of-use assets and lease liabilities at the lease commencement date. The assets are measured at the lease liability initially recognized, which comprises the present value of the future lease payments adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

The right-of-use assets are depreciated to the earlier of the end of the useful life of the asset or the lease term using the straight-line method as this most closely reflects the expected pattern of consumption of the future economic benefits. The Company presents right-of-use assets as its own line item on the consolidated statements of financial position. In determining the lease term, management considers the non-cancellable period along with all the facts and circumstances that create an economic incentive to exercise an extension option, or not to exercise a termination option. In addition, the right-of-use assets are periodically reduced by impairment losses, if any, and adjusted for certain remeasurements of the lease liabilities. The depreciation term of the right-of-use assets is between two and five years.

g) Lease Liabilities

Lease liabilities are initially measured at the present value of the future lease payments, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate, which is determined based on judgements about the economic environment in which the Company operates and theoretical analyses about the security provided by the underlying leased asset, the amount of funds required to be borrowed in order to meet the future lease payments associated with the lease asset, and the term for which these funds would be borrowed.

The lease liabilities are measured at amortized cost using the effective interest rate method. They are remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liabilities are remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use assets, or is recorded in statement of income and other comprehensive income if the carrying amount of the right-of-use assets has been reduced to zero. Lease payments are applied against the lease liabilities, with a portion allocated as cash finance expense using the effective interest rate method. The Company presents lease liabilities as their own line item on the consolidated statements of financial position.

h) Impairment

i) Financial assets

The Company has elected to measure loss allowances for trade receivables and contract assets at an amount equal to lifetime expected credit losses ("ECLs"). The maximum period considered when estimating ECLs is the maximum contractual period over which the Company is exposed to credit risk.

Loss allowances for financial assets are deducted from the gross carrying amount of the assets. Impairment losses on financial assets are presented under "other expenses" in the consolidated statements of income and comprehensive income.

ii) Non-financial assets

The carrying amounts of the Company's property, plant and equipment, which includes development and production assets, are reviewed at each period end date to determine whether there are any internal or external indicators of impairment or impairment reversal. If any such indicator exists, then the recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together at a CGU level. The estimated recoverable amount of an asset or a CGU is determined based on the higher of its fair value less costs of disposal ("FVLCD") and its value-in use ("VIU"). FVLCD is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The FVLCD of development and production assets is generally determined as the net present value of estimated future cash flows expected to arise from the continued use of the CGU and its eventual disposition, using assumptions that an independent market participant may take into account. These cash flows are discounted by an appropriate discount rate which would be applied by such a market participant to arrive at a net present value of the CGU. In determining VIU, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. VIU is generally the future cash flows expected to be derived from production of proved and probable oil and gas reserves estimated by the Company's independent third-party reserve evaluators.

An impairment is recognized if the carrying amount of a CGU exceeds the estimated recoverable amount for that CGU. The Company determines the estimated recoverable amount by using the greater of FVLCD and the VIU. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amount of assets in the unit (group of units) on a pro rata basis. Impairment losses are recognized in the consolidated statements of income and comprehensive income. The Company has two CGUs, the Eastern Heavy Oil CGU and the West Central CGU.

E&E assets are assessed for impairment within the related CGU at the time that any triggering facts and circumstances suggest that the carrying amount exceeds the estimated recoverable amount as well as upon their eventual reclassification to development and production assets in property, plant and equipment.

In respect of other assets, impairment losses recognized in prior years are assessed at each period end date for any indication that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

i) Share based payments

Fixed equity awards granted under equity-settled share based payment plans and agreements are measured at grant date fair value. Fair values are determined by means of an option pricing model using the exercise price of the equity instrument granted, the share price at the grant date, the expected life of the grant based on the vesting date and expiry date, estimates of share price volatility, and interest rates over the expected contractual life of the equity award. A forfeiture rate is estimated on the grant date and is subsequently adjusted to reflect the actual number of options that vest.

The costs of the equity-settled share based payments are recognized within the consolidated statements of income and comprehensive income, with a corresponding increase in contributed surplus over the vesting period. Upon exercise or settlement of an equity-based instrument, consideration received, and associated amounts previously recorded in contributed surplus are recorded to share capital.

Rubellite's accounting of share based compensation was modified on December 31, 2024 from equity-settled to cash-settled awards following the guidance of IFRS 2 *share based payments*.

Liabilities associated with cash-settled awards are determined based on the fair value of the award at the grant date and are subsequently revalued at each period end. These values are determined by means of an option pricing model using the period end share price, the number of awards outstanding at each period end date, the expected life of the grant based on the vesting date, estimates of share price volatility, interest rates in effect at the end of the reporting period, estimated forfeiture rates and certain management estimates, such as performance multipliers.

The costs of the cash-settled, share based payments is recognized in the statements of income and other comprehensive income over the relevant service period with an corresponding increase or decrease in accrued liabilities. Classification of the associated short-term and long-term liabilities is dependent on the expected payout dates of the individual awards.

j) Provisions

Provisions are recognized when the Company has a current legal or constructive obligation as a result of a past event, which can be reliably estimated, and will require the outflow of economic resources to settle the obligation. A non-current provision is determined using the estimated future cash flows discounted at a rate that reflects current market conditions and obligation specific risks.

(i) Decommissioning obligations

The Company's activities give rise to dismantling, decommissioning, and site disturbance remediation activities. A provision is recorded for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's estimate of the extent and timing of expenditures required to settle the obligation at the consolidated statement of financial position date, using a risk-free interest rate not adjusted for credit risk. Subsequent to the initial measurement, the obligation is adjusted at the end of each reporting period to reflect the passage of time, changes in the timing and estimate of future cash flows underlying the obligation and changes in the risk-free rate. The accretion of the provision due to the passage of time is recognized in the consolidated statements of income and comprehensive income whereas changes in the provision arising from changes in estimated cash flows or changes in the risk-free rate are capitalized in the consolidated statement of financial position. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

(ii) Other provisions

Other provisions are measured at the present value of management's estimate of the extent and timing of expenditures required to settle the obligation at the consolidated statement of financial position date, using a risk-free interest rate not adjusted for credit risk. Subsequent to the initial measurement, the obligation is adjusted at the end of each reporting period to reflect the passage of time, changes in the timing and estimate of future cash flows underlying the obligation and changes in the risk-free rate. The accretion of the provision due to the passage of time is recognized in the consolidated statements of income and comprehensive income whereas changes in the provision arising from changes in estimated cash flows or changes in the risk-free rate are capitalized in the consolidated statement of financial position. Actual costs incurred upon settlement of the other provision are charged against the provision to the extent the provision was established.

k) Revenue

Revenue from the sale of heavy crude oil, natural gas and natural gas liquids ("NGL") is recognized based on the consideration specified in contracts with customers. The Company recognizes revenue when control of the product transfers to the buyer and collection is reasonably assured. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the transportation method agreed upon.

l) Income tax

Income tax expense comprises current and deferred components. Income tax expense is recognized in the consolidated statements of income and comprehensive income except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

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

Deferred tax is recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the period end date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be sufficient to utilize the underlying deductible temporary differences and unused tax losses associated with the deferred tax asset. The determination of probable future taxable profits involves significant estimates, including proved and probable oil and gas reserves. Deferred tax assets are reviewed at each period end date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

m) Income per share amounts

Basic income, or loss, per share is calculated by dividing the net income, or loss, by the weighted average number of common shares outstanding during the period. For the dilutive net income per share calculation, the weighted average number of shares outstanding is adjusted for the potential number of shares which may have a dilutive effect on net income.

Diluted income per share is calculated giving effect to the potential dilution that would occur if outstanding warrants, share options, restricted share units or performance share units were exercised or converted into common shares. The weighted average number of diluted shares is calculated in accordance with the treasury stock method for warrants, share options, restricted share units and performance share units. The treasury stock method assumes that the proceeds received from the exercise of all potentially dilutive instruments are used to repurchase common shares at the average market price. For diluted earnings per share, share based payment arrangements that may be settled in shares or cash are treated as equity settled where the assumed issuance of shares would be dilutive.

n) Future Accounting Pronouncements

In April 2024, the IASB issued IFRS 18 *Presentation and Disclosure in Financial Statements* ("IFRS 18"), which will replace IAS 1 and includes requirements for all entities applying IFRS Accounting Standards for the presentation and disclosure of information in the financial statements. IFRS 18 will introduce new totals, subtotals and categories for income and expenses in the statement of income and comprehensive income, as well as requiring disclosure about management defined performance measures and additional requirements regarding the aggregation and disaggregation of certain information. It will be effective on January 1, 2027, with earlier adoption permitted and it must be adopted on a retrospective basis. Rubellite is currently evaluating the impact of this standard on its consolidated financial statements.

In May 2024, the IASB issued amendments to IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* relating to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. The amendments will be effective on January 1, 2026, and are not expected to have a material impact on the Company's consolidated financial statements.

4. PROPERTY, PLANT AND EQUIPMENT

a) Property, Plant And Equipment

		Development and Production Assets		Corporate Assets		Total
Cost						
December 31, 2023	$	245,156	$	—	$	245,156
Additions		90,680		3,097		93,777
Transfer from exploration and evaluation (note 5)		20,796		—		20,796
Acquisitions (note 4c)		173,818		2,737		176,555
Change in decommissioning obligations related to PP&E (note 8a)		19,532		—		19,532
December 31, 2024	$	549,982	$	5,834	$	555,816
Additions		**122,600**		**529**		**123,129**
Change in decommissioning obligations related to PP&E (note 8a)		**4,572**		**—**		**4,572**
December 31, 2025	**$**	**677,154**	**$**	**6,363**	**$**	**683,517**
Accumulated depletion and depreciation						
December 31, 2023	$	(42,953)	$	—	$	(42,953)
Depletion and depreciation		(50,317)		(550)		(50,867)
December 31, 2024	$	(93,270)	$	(550)	$	(93,820)
Depletion and depreciation(1)		**(92,812)**		**(1,438)**		**(94,250)**
December 31, 2025	**$**	**(186,082)**	**$**	**(1,988)**	**$**	**(188,070)**
Carrying amount						
December 31, 2024	$	456,712	$	5,284	$	461,996
December 31, 2025	**$**	**491,072**	**$**	**4,375**	**$**	**495,447**

(1) During the year ended December 31, 2025, depletion, as presented in the table, excludes $0.7 million which has been capitalized to inventory (December 31, 2024 - $1.1 million).

As at December 31, 2025, future development costs of $457.6 million (December 31, 2024 – $436.3 million) associated with proved and probable oil and gas reserves were included in the depletion calculation and an estimated $12.4 million (December 31, 2024 – $8.7 million) of salvage value for production equipment was excluded. Depletion expense was $92.8 million (December 31, 2024 - $50.3 million) on development and production assets for the year ended December 31, 2025.

During the year ended December 31, 2025, the Company added $0.5 million of corporate assets (December 31, 2024 - $5.8 million) and recorded depreciation expense of $1.4 million (December 31, 2024 - $0.6 million).

b) Impairment

Eastern Heavy Oil CGU

At December 31, 2025 and December 31, 2024, the Company assessed its Eastern Heavy Oil CGU for indicators of impairment and concluded that the estimation of recoverable amount was not required, therefore no impairment test was required.

The Company transferred $20.8 million of E&E to PP&E during 2024 and performed the required impairment test to estimate the recoverable amount of the CGU. It was determined that the recoverable amount of the CGU exceeded its carrying value, resulting in no impairment. The Company did not transfer E&E to PP&E during 2025, therefore no impairment test was required.

West Central CGU

At December 31, 2025, the Company completed an assessment to determine if indicators of impairment existed within the West Central CGU. As a result of the assessment, the Company determined that indicators of impairment existed at December 31, 2025 as the carrying amount of the CGU may exceed the recoverable amount. The Company performed the required impairment test using the VIU approach incorporating benchmark pricing based on the average of the three independent reserve evaluators' forecast and utilizing a discount rate of 15%. The test determined that the recoverable amount of the West Central CGU exceeded its carrying value as at December 31, 2025 and as a result, no impairment was recognized.

c) Acquisitions and Dispositions

During 2025, the Company disposed of undeveloped land for proceeds of $7.8 million and recorded a corresponding gain on disposition.

Recombination Transaction with Perpetual Energy Inc. ("Perpetual") - October 31, 2024

Effective October 31, 2024, Rubellite Energy Inc. and Perpetual effected a Recombination Transaction by way of an arrangement resulting in the recombination of the two entities into a new entity being Rubellite Energy Corp.. In accordance with the Recombination Transaction, (i) holders of common shares of Rubellite Energy Inc. received (1) common share of the Company for every (1) common share of Rubellite Energy Inc. held, (ii) holders of common shares of Perpetual received (1) common share of the Company for every (5) Perpetual shares held, and (iii) Perpetual's outstanding senior notes ($26.2 million in face value) were converted into 11.6 million common shares of the Company at a conversion price of $2.25 per common share.

Judgement was required to determine which entity is the acquirer in the Recombination Transaction. When identifying Rubellite as the acquirer for accounting purposes, management analyzed voting rights of all instruments, the intended corporate structure, the intended composition of management of the recombined Company and the size of each of the companies. No single factor was a sole determinant in the overall conclusion that Rubellite Energy Inc. was the acquirer for accounting purposes resulting in the Recombination Transaction being accounted for in accordance with IFRS 3 *Business Combinations*.

The Recombination Transaction was accounted for as a business combination using the acquisition method of accounting, whereby the assets acquired and the liabilities assumed are recorded at the estimated fair value on the acquisition date of October 31, 2024 with the exception of income taxes, right-of-use asset and lease liability. There were $4.2 million of transaction costs incurred by the Company in 2024 which were expensed through the consolidated statement of income and comprehensive income. The conventional natural gas assets acquired were included in a new West Central CGU.

The Recombination Transaction resulted in the issuance of 25.4 million common shares, issued at Rubellite's closing share price on October 31, 2024 of $2.04 per share, for a total purchase price of $47.7 million (note 9b).

The purchase price was allocated based on management's estimates of fair values:

Assets acquired		
Oil and natural gas interests (note 4)	$	63,038
Net working capital deficiency (note 16)		(6,356)
Right-of-use asset (note 6)		5,036
Exploration and evaluation assets (note 5)		2,692
Corporate assets (note 4)		2,737
Risk management contracts (note 17)		10,132
Lease liability (note 7)		(5,036)
Share based compensation liability (note 10)		(2,925)
Other provision (note 8b)		(18,481)
Decommissioning provisions (note 8a)		(3,128)
Deferred tax asset (note 14)		31,569
Gain on acquisition (note 14)		(31,569)
Net assets acquired	**$**	**47,709**

Consideration		
Shares (note 9b)		51,732
Settlement of pre-existing relationship[1]	$	(4,023)
Total consideration paid	**$**	**47,709**

(1) Until the Recombination Transaction in 2024, Rubellite and Perpetual were considered related parties due to the existence of a Management and Operating Services Agreement ("MSA"). Included within working capital was $4.0 million accounts payable related to a contractual pre-existing relationship which was deemed to be settled as a result of the Recombination Transaction.

For the comparative year, 2024 results from the operations of Perpetual are included in the Company's consolidated financial statements from the closing date of the Recombination Transaction. Oil and natural gas revenue of $4.2 million and net income of $1.8 million were included in the consolidated statements of income and comprehensive income from the closing of the Recombination Transaction on October 31, 2024 to December 31, 2024. If the Recombination Transaction had occurred on January 1, 2024 the estimated incremental oil and natural gas revenue and net income for the year ended December 31, 2024, would have been $24.3 million and $11.0 million, respectively.

The acquisition date fair value attributed to the oil and natural gas interests was derived from the estimate of proved and probable oil and gas reserves and the related cash flows prepared at December 31, 2023 by independent third-party reserve evaluators and updated by internal reserve evaluators to reflect activity and commodity price assumptions up to October 31, 2024. The proved and probable oil and gas reserves and related cash flows were discounted using rates between 20% and 35%. The fair value of decommissioning obligations was initially estimated using a credit adjusted risk-free rate of 11.5%.

Acquisition of Buffalo Mission Energy Corp. ("Buffalo Mission") - August 2, 2024

Effective August 2, 2024, Rubellite Energy Inc. acquired all of the issued and outstanding common shares of Buffalo Mission for a total purchase price of $96.6 million, inclusive of $23.5 million of Buffalo Mission's assumed net debt(1), which consisted of $62.7 million in cash and the issuance of 5.0 million of common shares (note 9b) of Rubellite to certain shareholders of Buffalo Mission valued at $10.4 million using Rubellite Energy Inc.'s closing share price on August 2, 2024 of $2.07 per share (the "BMEC Acquisition").

The BMEC Acquisition was accounted for as a business combination using the acquisition method of accounting, whereby the assets acquired and the liabilities assumed were recorded at the estimated fair value on the acquisition date of August 2, 2024. In 2024, there were $2.0 million of transaction costs incurred by the Company which were expensed through the consolidated statement of income and comprehensive income. The assets acquired in this transaction were included in the Eastern Heavy Oil CGU.

The purchase price was allocated based on management's estimates of fair values:

Assets acquired		
Oil and gas interests (note 4)	$	110,780
Net working capital deficiency(1)		(21,204)
Deferred tax liabilities (note 14)		(15,795)
Decommissioning provisions (note 8a)		(699)
Net assets acquired	**$**	**73,082**

Consideration		
Cash(2)	$	62,732
Share (note 9b)		10,350
Total consideration paid	**$**	**73,082**

(1) Assumed net debt excluded inventory and other items which are included in net working capital.
(2) Rubellite funded the transaction in 2024 through; the expansion of the credit facility to $100.00 million from $60.0 million (note 12), a $20.0 million bank syndicate term loan which was repaid on October 31, 2024 and a new second lien term loan ("term loan") placed, directly or indirectly, with certain directors and officers, and their affiliates, of Rubellite and the Company's significant shareholder for $20.0 million (note 13).

The Company used estimated proved and probable reserves from an independent third-party reserve evaluation to estimate the acquisition date fair value of oil and gas interests acquired. For the purposes of estimating the acquisition date fair value of the oil and gas interests acquired, the Company's independent third-party reserve evaluator provided an estimate of proved and probable oil and gas reserves as at August 2, 2024. The estimated proved and probable oil and gas reserves and related cash flows were discounted using rates between 15% and 30%. The fair value of decommissioning obligations was initially estimated using a credit adjusted risk-free rate of 11.5%.

For the comparative year of 2024, oil and gas revenue of $26.3 million and net income of $15.2 million were included in the consolidated statements of income and comprehensive income since the closing of the BMEC Acquisition on August 2, 2024. If the BMEC Acquisition had occurred on January 1, 2024 the estimated incremental oil and natural gas revenue and net income for the year ended December 31, 2024, would have been $37.3 million and $22.9 million, respectively.

5. EXPLORATION AND EVALUATION

		December 31, 2025		December 31, 2024
Balance, beginning of year	**$**	**29,106**	$	32,301
Acquisitions (note 3c)		**—**		2,692
Additions		**7,373**		15,129
Transfer to property, plant, and equipment (note 4a)		**—**		(20,796)
Exploration and evaluation expense		**(5,425)**		(220)
Balance, end of year	**$**	**31,054**	$	29,106

Exploration and evaluation ("E&E") expense was $5.5 million (December 31, 2024 - $0.5 million) for the year ended December 31, 2025, which included $5.4 million related to two (2.0 net) exploration wells and land costs that were previously recorded as E&E and $0.1 million of costs directly charged to E&E expense.

Impairment of E&E assets

E&E assets are tested for impairment when internal or external indicators of impairment exist or upon transfer to oil and gas interests in PP&E. At December 31, 2025, management's assessment determined there were no indicators of impairment.

6. RIGHT-OF-USE ASSETS

The Company leases certain assets including office space, vehicles, and other leases. Information about lease obligations for which the Company is a lessee is presented below:

	Head office	Vehicles	Other leases	Total
Cost				
January 1, 2024	$ —	$ —	$ —	$ —
Acquisitions (note 4c)	4,782	190	64	5,036
December 31, 2024	$ 4,782	$ 190	$ 64	$ 5,036
Additions	—	140	—	140
December 31, 2025	**$ 4,782**	**$ 330**	**$ 64**	**$ 5,176**
Accumulated depreciation				
January 1, 2024	$ —	$ —	$ —	$ —
Acquisitions (note 4c)	(77)	(23)	(6)	(106)
December 31, 2024	$ (77)	$ (23)	$ (6)	$ (106)
Depreciation	(459)	(127)	(37)	(623)
December 31, 2025	**$ (536)**	**$ (150)**	**$ (43)**	**$ (729)**
Carrying amount				
December 31, 2024	$ 4,705	$ 167	$ 58	$ 4,930
December 31, 2025	**$ 4,246**	**$ 180**	**$ 21**	**$ 4,447**

7. LEASE LIABILITIES

	December 31, 2025	December 31, 2024
Balance, beginning of year	**$ 4,965**	$ —
Additions (note 6)	**140**	—
Acquisition (note 4c)	**—**	5,036
Interest on lease liabilities (note 15)	**316**	55
Payments	**(692)**	(126)
Total lease liabilities	**$ 4,729**	$ 4,965
Current	**$ 389**	$ 357
Non-current	**4,340**	4,608
Total lease liabilities	**$ 4,729**	$ 4,965

Lease terms are negotiated on an individual basis and contain a wide range of terms and conditions. Incremental borrowing rates used to measure the present value of the future lease payments at December 31, 2025 were between 4.3% and 6.6% (December 31, 2024 - 4.3% and 6.6%).

8. PROVISIONS

a) Decommissioning obligations

		December 31, 2025		December 31, 2024
Balance, beginning of year	$	31,817	$	8,593
Liabilities settled		(1,851)		(451)
Obligations incurred		2,813		3,535
Obligations acquired (note 4c)		—		3,827
Change in rate on acquisition (note 4c)		—		13,586
Revisions to estimates		1,759		2,411
Accretion (note 15)		1,104		316
Total decommissioning obligations, end of year	$	35,642	$	31,817
Decommissioning obligations - current	$	1,340	$	2,000
Decommissioning obligations - non-current		34,302		29,817
Total decommissioning obligations	$	35,642	$	31,817

Decommissioning obligations are estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities, and the estimated timing of the costs to be incurred in future periods.

The increase in the provision due to the passage of time, which is referred to as accretion, is recognized as non-cash finance expense in the consolidated statements of income and comprehensive income. Decommissioning obligations are further adjusted at each period end date for changes in the risk-free interest rate, after considering additions and dispositions of PP&E. Decommissioning obligations are also adjusted for revisions to future cost estimates and the estimated timing of costs to be incurred in future periods.

The following significant assumptions were used to estimate the Company's decommissioning obligations:

		December 31, 2025		December 31, 2024
Undiscounted obligations	$	49,432	$	42,085
Average risk-free rate		3.9%		3.3%
Inflation rate		2.0%		1.8%
Expected timing of settling obligations		1 to 25 years		1 to 25 years

b) Other provision

		December 31, 2025		December 31, 2024
Balance, beginning of year	$	18,574	$	—
Provision acquired (note 4c)		—		18,481
Payments		(3,750)		—
Accretion (note 15)		480		93
Total other provision, end of year	$	15,304	$	18,574
Other provision - current	$	3,750	$	3,750
Other provision - non-current		11,554		14,824
Total other provision	$	15,304	$	18,574

The other provision was assumed as part of the Recombination Transaction and relates to a "Settlement Agreement" Perpetual entered into to resolve litigation by providing amounts to settle asset retirement obligations without any party admitting liability, wrongdoing or violation of laws, regulations, public policy or fiduciary duties. The Company will make annual installment payments of $3.75 million until the total amount of the Settlement Principal is paid. The annual scheduled payment was made on March 28, 2025 and all scheduled payments made prior to March 28, 2026 will have the interest forgiven. As of March 28, 2026, interest will accrue and be payable on the outstanding Settlement Principal annually at an interest rate equal to the applicable Bank of Canada prime rate on the date of payment. The Company is able to pre-pay all, or any portion, of the outstanding balance of the Settlement Principal at any time without bonus or penalty. The other provision is a second-lien obligation of the Company.

The following assumptions were used to estimate the Company's other provision:

		December 31, 2025		December 31, 2024
Undiscounted obligation	$	16,191	$	19,941
Average risk-free rate		3.0%		3.0%
Expected timing of settling obligation		4.3 years		5.3 years

9. SHARE CAPITAL

a) Authorized

Authorized capital consists of an unlimited number of common shares.

b) Issued and outstanding

	December 31, 2025		December 31, 2024	
	Shares *(thousands)*	**Amount *($thousands)***	Shares *(thousands)*	Amount *($thousands)*
Balance, beginning of year	**92,877**	**$ 206,313**	62,456	$ 143,033
Common shares issued (note 4c)	**—**	**—**	30,192	62,082
Issued pursuant to share based plans[1]	**716**	**1,533**	229	1,567
Share issue costs [2]	**—**	**(173)**	—	(369)
Balance, end of year	**93,593**	**$ 207,673**	92,877	$ 206,313

(1) Share capital is presented net of the shares held by the Trustee that have not been issued to employees (note 9c). As at December 31, 2025 there were 0.1 million shares held in trust (December 31, 2024 - 0.2 million).
(2) Share issue costs for the year ended December 31, 2025 are net of $0.2 million of deferred tax (December 31, 2024 - $0.4 million).

During the year ended December 31, 2025, the Company issued 0.7 million common shares (December 31, 2024 - 0.2 million common shares) pursuant to share based compensation plans.

On October 31, 2024, in conjunction with the closing of the Recombination Transaction, Rubellite issued 25.4 million common shares which were valued at $51.7 million using the Company's share price on the closing date of the transaction of $2.04 per share. At closing of the Recombination Transaction, 4.0 million Share Purchase Warrants, which were issued to Perpetual on September 3, 2021 valued at $2.0 million, were cancelled on October 31, 2024 and are no longer outstanding.

On August 2, 2024, in conjunction with the closing of the acquisition of Buffalo Mission, Rubellite issued 5.0 million common shares to certain shareholders of Buffalo Mission, which were valued at $10.4 million using the Company's share price on the closing date of the transaction of $2.07 per share.

c) Per share information

(*thousands, except per share amounts*)	**December 31, 2025**	December 31, 2024
Net income	**$ 32,557**	$ 49,973
Weighted average shares		
Issued common shares	**93,694**	93,044
Effect of shares held in trust[1]	**(101)**	(167)
Issued common shares, net of shares held in trust[2]	**93,593**	92,877
Weighted average common shares outstanding – basic	**93,283**	68,667
Weighted average common shares outstanding – diluted	**96,036**	69,716
Net income per share – basic	**$ 0.35**	$ 0.73
Net income per share – diluted	**$ 0.34**	$ 0.72

(1) As result of the Recombination Transaction, the Company has compensation agreements in place with employees whereby they may be entitled to receive shares of the Company purchased on the open market by a trustee (note 10). The shares purchased by the independent trustee are reported as shares held in trust.
(2) Share capital is presented net of the shares held by the Trustee that have not been issued to employees. As at December 31, 2025 there were 0.1 million shares held in trust (December 31, 2024 - 0.2 million).

Per share amounts have been calculated using the weighted average number of common shares outstanding. For the year ended December 31, 2025, of the 10.9 million common shares issuable upon the exercise or settlement of share based compensation instruments, 8.1 million instruments (December 31, 2024 - 8.3 million instruments) were excluded from diluted earnings per share, including share units which the Company can elect to settle in cash, as the effect was anti-dilutive.

10. SHARE BASED PAYMENTS

Share based payment awards that were included as part of the Recombination Transaction with Perpetual (note 4c) were initially recorded at their fair value on the closing date of October 31, 2024 using the cash settled accounting method under IFRS 2 and subsequently revalued at December 31, 2024.

The following table summarizes the changes in the share based compensation liability:

		December 31, 2025		December 31, 2024
Balance, beginning of year	**$**	**6,271**	$	—
Reclassified from contributed surplus[(1)]		**—**		3,696
Share based compensation liability acquired (note 4c)		**—**		2,925
Share based payment expense		**5,368**		282
Cash settlement		**(3,202)**		(632)
Equity settlement		**(1,533)**		—
Balance, end of year[(2)]	**$**	**6,904**	$	6,271
Share based compensation liability - current	**$**	**4,694**	$	5,357
Share based compensation liability - non-current		**2,210**		914
Total share based compensation liabilities	**$**	**6,904**	$	6,271

(1) During 2024, the Company modified its share options, performance share units and restricted share units from equity-settled to cash-settled share based compensation awards. The fair values of the awards previously expensed were reclassified from contributed surplus to a share based compensation liability.
(2) The Company's share based payment liability can be settled through the issuance of cash or shares.

The components of share based compensation expense are as follows:

		December 31, 2025		December 31, 2024
Share based payment expense	**$**	**6,060**	$	3,289
Fair value adjustment		**(692)**		282
Share based payment expense	**$**	**5,368**	$	3,571

The following tables summarize information about options, rights and awards outstanding:

Rubellite incentive plan compensation awards

(number of awards, thousands)	**Share options**	**Performance share units**	**Restricted share units**	**Total**
December 31, 2024	3,052	605	2,526	6,183
Granted	350	1,620	1,892	3,862
Exercised for common shares	(54)	(562)	(411)	(1,027)
Exercised for cash	—	—	(533)	(533)
Performance adjustment	—	281	—	281
Forfeited	(47)	—	(159)	(206)
December 31, 2025	**3,301**	**1,944**	**3,315**	**8,560**

Legacy Perpetual compensation awards - Recombination Transaction[(1)(2)]

(number of awards, thousands)	**Deferred options**	**Deferred shares**	**Share options**	**Performance share rights**	**Total**
December 31, 2024[(3)]	1,189	568	902	532	3,191
Exercised for common shares	—	—	(12)	—	(12)
Exercised for shares held in trust	(95)	(51)	(41)	—	(187)
Exercised for cash	(163)	(242)	(60)	(111)	(576)
Performance adjustment	—	—	—	(110)	(110)
Forfeited	—	(16)	—	—	(16)
December 31, 2025[(3)]	**931**	**259**	**789**	**311**	**2,290**

(1) Recognized as part of the Recombination Transaction.
(2) Awards previously issued by Perpetual, which were acquired through the Recombination Transaction, were adjusted at the equity conversion ratio of 5:1.
(3) Total awards outstanding include 1.6 million legacy Perpetual awards that can be settled for cash or from shares in the trust as opposed to treasury. Shares in the trust as at December 31, 2025 were 0.1 million (December 31, 2024 - 0.2 million) (note 9c).

During the year ended December 31, 2025, the Company granted 3.9 million share based compensation awards, comprised of share options, performance share units and restricted share units.

a) Deferred options

As a result of the Recombination Transaction, the Company has legacy Perpetual deferred option agreements with certain employees whereby they may be entitled to receive cash or shares of the Company purchased on the open market by an independent trustee if they remain employees of the Company and exercise their deferred options. Legacy Perpetual deferred options generally vest over four years, one quarter on each year of the term, with expiry occurring five years after issuance. The shares purchased by the independent trustee are reported as shares held in trust (note 9c).

The Company uses the Black-Scholes pricing model to calculate the estimated fair value of the legacy Perpetual deferred options and performance based long-term incentive awards. The following assumptions were used to arrive at the estimate of fair value as at December 31, 2025:

	December 31, 2025	December 31, 2024
Dividend yield (%)	—	—
Forfeiture rate (%)	**5.00**	5.00
Expected volatility (%)	**41.39**	48.61
Risk-free interest rate (%)	**2.54**	2.89
Contractual life (years)	**5.0**	5.0
Weighted average share price at grant date	**$ 2.67**	$ 2.50
Closing share price	**$ 2.40**	$ 2.12

The following table summarizes information about the deferred options outstanding:

	Legacy Perpetual deferred options outstanding			**Deferred options exercisable**	
Range of exercise prices	**Number of deferred options (thousands)**	**Average contractual life (years)**	**Weighted average exercise price ($/share)**	**Number of deferred options (thousands)**	**Weighted average exercise price ($/share)**
$0.00 to $2.00	350	0.65	1.70	350	1.70
$2.01 to $4.00	302	2.76	2.76	156	2.77
$4.01 to $6.65	279	1.61	5.10	208	5.10
Total	**931**	**1.62**	**3.06**	**714**	**2.93**

b) Share options

The Rubellite Incentive Plan provides for the granting of share options to provide a long-term incentive to directors, executive officers, employees or consultants associated with the Company's long-term performance. The Board of Directors administers the granting of share options and determines participants, number of share options and terms of vesting. The exercise price of the share options granted shall not be less than the value of the weighted average trading price for the Company's common shares for the five trading days immediately preceding the date of grant. Share options granted generally vest evenly over four years, commencing on the first anniversary, with expiry occurring five years after issuance. Rubellite share options, derived from legacy Perpetual share options through the Recombination Transaction and adjusted for the share exchange ratio of 5:1, were awarded under the same terms.

The Company uses the Black-Scholes pricing model to calculate the estimated fair value of the share option awards. The following assumptions were used to arrive at the estimate of fair value as at December 31, 2025:

	December 31, 2025	December 31, 2024
Dividend yield (%)	—	—
Forfeiture rate (%)	**5.00**	5.00
Expected volatility (%)	**42.96**	48.61
Risk-free interest rate (%)	**2.61**	2.89
Contractual life (years)	**5.0**	5.0
Weighted average share price at grant date	**$ 2.34**	$ 0.81
Closing share price	**$ 2.40**	$ 2.12

The following tables summarize information about the share option awards outstanding at December 31, 2025:

	Options outstanding			**Options exercisable**	
Range of exercise prices	**Number of share options (thousands)**	**Average contractual life (years)**	**Weighted average exercise price ($/share)**	**Number of share options (thousands)**	**Weighted average exercise price ($/share)**
$0.00 to $2.00	687	0.79	1.99	667	1.99
$2.01 to $2.89	1,739	3.32	2.17	607	2.12
$2.90 to $3.65	875	1.62	2.99	657	2.99
Total	**3,301**	**2.34**	**2.35**	**1,931**	**2.37**

Legacy Perpetual share option awards from the Recombination Transaction

The Company uses the Black-Scholes pricing model to calculate the estimated fair value of the legacy Perpetual share option awards from the Recombination Transaction. The following assumptions were used to arrive at the estimate of fair value as at December 31, 2025:

	December 31, 2025	December 31, 2024
Dividend yield (%)	**—**	—
Forfeiture rate (%)	**5.00**	5.00
Expected volatility (%)	**41.27**	49.79
Risk-free interest rate (%)	**2.55**	2.89
Contractual life (years)	**5.0**	5.0
Weighted average share price at grant date	**$ 2.83**	$ 2.83
Closing share price	**$ 2.40**	$ 2.12

The following tables summarize information about the legacy Perpetual share option awards outstanding:

	Legacy Perpetual Share Options outstanding			**Share Options exercisable**	
Range of exercise prices	**Number of share options (thousands)**	**Average contractual life (years)**	**Weighted average exercise price ($/share)**	**Number of share options (thousands)**	**Weighted average exercise price ($/share)**
$0.00 to $2.00	236	0.52	1.54	236	1.54
$2.01 to $3.00	291	2.78	2.73	146	2.73
$3.01 to $6.65	262	1.61	5.16	194	5.18
Total	**789**	**1.71**	**3.18**	**576**	**3.07**

c) Deferred shares

As a result of the Recombination Transaction, the Company has deferred share agreements in place with directors and certain employees. In the case of directors, the legacy Perpetual deferred shares granted vest upon retirement from the Board of Directors and for employees, the legacy Perpetual deferred shares vest over a two year period if they remain employees of the Company during such time. Upon vesting, directors and employees may be entitled to receive, at the discretion of the Board of Directors, cash, a grant of restricted rights (note 9c), or shares of the Company purchased on the open market by an independent trustee. The shares purchased by the independent trustee are reported as shares held in trust (note 9c).

The Company accounts for the deferred shares using the cash-settled method under IFRS 2 and uses an intrinsic pricing model to calculate the estimated fair value of the deferred shares at the end of each reporting period. The share based compensation liability is reduced by an estimated forfeiture rate of 5% for outstanding awards and adjusted based on the Company's closing share price. The legacy Perpetual deferred shares were revalued at December 31, 2025 using Rubellite's closing share price of $2.40 per share.

d) Performance share units and performance share rights

The Rubellite Incentive Plan provides for the granting of performance share units for the Company's executive officers. Performance share units vest two years after the date upon which the performance units were granted for awards issued in 2023 and 2024 and over three years for awards granted in 2025. The performance share units that vest and become redeemable for equivalent common shares are a multiple of the performance share units granted, dependent upon the achievement of certain performance metrics over the vesting period. Vested performance share units can be settled in cash or in common shares of the Company at the discretion of the Board of Directors. Performance share units are forfeited if plan participants leave the organization other than through retirement or termination without cause prior to the vesting date. Legacy Perpetual Performance share rights, which were acquired from Perpetual in the Recombination Transaction, were awarded under the same terms and were adjusted for the exchange ratio of 5:1 through the Recombination Transaction.

The fair value of a performance share unit award is determined at the date of grant by using the closing price of common shares multiplied by the estimated performance multiplier. A performance factor of 2.0 was applied to performance share units which vested in the first quarter of 2025. As at December 31, 2025, performance factors of 0.8 and 0.9 has been assumed for unvested performance share units granted in 2024 and 2025, respectively. Fluctuations in share based payments may occur due to changes in estimates of performance outcomes.

The fair value of the legacy Perpetual performance share right awards is determined at the date of grant by using the closing price of common shares multiplied by the estimated performance multiplier. A performance factor of 0.5 was applied to performance share rights which vested in the first quarter of 2025 for awards granted by Perpetual in 2023. As at December 31, 2025, a performance factor of 0.6 has been assumed for unvested legacy Perpetual performance share rights granted in 2024 which were acquired through the Recombination Transaction. Fluctuations in share based payments may occur due to changes in estimates of performance outcomes.

The Company accounts for the performance share units and legacy Perpetual performance share rights using the cash-settled method under IFRS 2 and uses an intrinsic pricing model to calculate the estimated fair value at the end of each reporting period. The share based compensation liability is reduced by an estimated forfeiture rate of 5% for outstanding awards and the Company's closing share price. The performance share units were revalued at December 31, 2025 using Rubellite's closing share price of $2.40 per share.

e) Restricted share units

The Rubellite Incentive Plan provides for the granting of restricted share units for directors, officers, employees or consultants. The restricted share units ("RSUs") vest proportionately annually over a two year period for units granted prior to November 1, 2024 and vest proportionately annually over a three year period for units granted after November 1, 2024. The restricted share units that vest can be settled in cash or in common shares, at the discretion of the Company.

The Company accounts for the restricted share units using the cash-settled method under IFRS 2 and uses an intrinsic pricing model to calculate the estimated fair value at the end of each reporting period. The share based compensation liability is reduced by an estimated forfeiture rate of 5% for outstanding awards and the Company's closing share price on December 31, 2025, 2025 of $2.40 per share.

11. OIL AND GAS REVENUE

The Company sells its production pursuant to fixed or variable price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver fixed or variable volumes of heavy crude oil, natural gas or NGL as may be applicable to the contract counterparty. Revenue is recognized when a unit of production is delivered to the contract counterparty. The amount of revenue recognized is based on the agreed transaction price, whereby any variability in revenue relates specifically to the Company's efforts to transfer production, therefore the resulting revenue is allocated to the sales production delivered in the period during which the variability occurs. As a result, none of the variable revenue is considered constrained.

The Company's properties currently produce heavy crude oil, natural gas and NGL volumes which are mostly sold under floating contracts of varying price and volume terms of up to one year with established creditworthy counterparties. Revenues are typically collected on the 25th day of the month following production and delivery to sales points. Included in accounts receivable at December 31, 2025 is $17.8 million of revenue related to December 2025 sales production (December 31, 2024 - $22.0 million of revenue related to December 2024 sales production).

	December 31, 2025	December 31, 2024
Oil	**$ 218,918**	$ 164,206
Natural gas	**15,030**	2,627
NGL	**7,752**	1,551
Oil and natural gas revenue	**$ 241,700**	$ 168,384

12. BANK DEBT

As at December 31, 2025, the Company's first lien credit facility had a borrowing limit of $140.0 million (December 31, 2024 - $140.0 million). The initial term is to May 31, 2026 and may be extended for a further twelve months to May 31, 2027 subject to lender approval. If not extended by May 31, 2026, all outstanding advances would be repayable on May 31, 2027. The next semi-annual borrowing base redetermination is scheduled on or before May 31, 2026.

As at December 31, 2025, $92.6 million was drawn against the credit facility (December 31, 2024 - $108.5 million) and $1.4 million (December 31, 2024 - $3.6 million) of letters of credit were issued. Borrowings under the credit facility bear interest at the lenders' prime rate or CORRA rates, plus applicable margins and standby fees. The applicable CORRA margins range between 2.8% and 6.3%. The effective aggregate interest rate on the credit facility at December 31, 2025 was 6.0% per annum. For the year ended December 31, 2025, if interest rates changed by 1% with all other variables held constant, the impact on cash finance expense and net income and comprehensive income would be $0.7 million.

The credit facility is secured by general first lien security agreements covering all present and future property of the Company.

At December 31, 2025, the credit facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

13. TERM LOAN

			December 31, 2025		December 31, 2024	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term loan	August 2, 2029	11.5%	**$ 20,000**	**$ 19,173**	$ 20,000	$ 19,027

On August 2, 2024, Rubellite entered into a $20.0 million senior secured second-lien term loan placed, directly or indirectly, with certain directors, officers and employees, and their affiliates, of Rubellite and the Company's significant shareholder. The term loan bears interest at 11.5% annually with interest payments to be paid quarterly, matures in five years from the date of issue, and can be repaid by the Company without penalty at any time. In conjunction with the closing of the Recombination Transaction, the term loan was converted to a third-lien obligation of the Company without any other modifications.

During the year ended December 31, 2025, Rubellite paid $2.3 million in cash interest payments to the holders of the term loan (December 31, 2024 - $1.0 million).

At December 31, 2025, the term loan was recorded at the present value of future cash flows, net of $0.8 million (December 31, 2024 - $1.0 million) in issue and discount costs which are amortized over the remaining term using a weighted average effective interest rate of 13.0%.

The term loan is not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

At December 31, 2025 and December 31, 2024, entities controlled or directed by the Company's Chief Executive Officer ("CEO") hold $18.4 million of the outstanding term loan.

14. DEFERRED TAXES

The provision for income taxes in the consolidated financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rate to the Company's net income before tax. The difference results from the following items:

		December 31, 2025		December 31, 2024
Income before income tax	**$**	**41,441**	$	59,033
Combined federal and provincial tax rate		**23%**		23%
Computed income tax expense		**9,532**	$	13,577
Increase (decrease) in income taxes resulting from:				
Non-deductible expenses		**524**		763
Non-taxable gain on acquisition		**—**		(7,272)
Other		**2**		(550)
Change in unrecognized deferred tax assets		**(1,174)**		2,542
Deferred tax expense	**$**	**8,884**	$	9,060

The following table summarizes the continuity of the net deferred tax asset of the Company:

		December 31, 2024		Recognized in earnings		Recognized in equity		**December 31, 2025**
Deferred tax assets (liabilities):								
Property, plant and equipment	$	(30,903)	$	(7,197)	$	—	**$**	**(38,100)**
Decommissioning obligations		7,318		880		—		**8,198**
Fair value of derivatives		(1,661)		396		—		**(1,265)**
Other liabilities		4,049		(1,229)		—		**2,820**
Share and debt issue costs		669		(82)		(173)		**414**
Non-capital losses		41,965		(1,652)		—		**40,313**
Deferred tax asset	$	21,437	$	(8,884)	$	(173)	**$**	**12,380**

		December 31, 2023		Recognized in earnings		Recognized in equity		Acquisitions		**December 31, 2024**
Deferred tax assets (liabilities):										
Property, plant and equipment	$	2,235	$	(12,638)	$	—	$	(20,500)	$	(30,903)
Decommissioning obligations		1,977		4,622		—		719		7,318
Fair value of derivatives		(2,148)		2,818		—		(2,331)		(1,661)
Other liabilities		—		(202)		—		4,251		4,049
Share and debt issue costs		562		380		(369)		96		669
Non-capital losses		12,417		(4,040)		—		33,588		41,965
Deferred tax asset	$	15,043	$	(9,060)	$	(369)	$	15,823	$	21,437

The deductible temporary differences included in the Company's unrecognized deferred tax assets relate to resource tax pools and amount to $43.4 million at December 31, 2025 (December 31, 2024 - $48.6 million).

As at December 31, 2025, the Company had approximately $175.3 million (December 31, 2024 – $182.5 million) of non-capital losses available for future use. The unused non-capital losses expire between 2036 and 2044.

The development and production assets and facilities owned by the Company have an approximate tax basis of $400.8 million (December 31, 2024 – $401.6 million) available for future use as deductions from taxable income, as indicated below:

		December 31, 2025		December 31, 2024
Canadian oil & gas properties	**$**	**107,630**	$	116,894
Canadian development expense		**238,479**		232,759
Undepreciated capital cost		**54,717**		51,903
Tax pools	**$**	**400,826**	$	401,556

Deferred tax assets have not been recognized in respect of capital losses of $1,069.9 million (December 31, 2024 - $143.8 million) and certain resource pools included above, because it is not probable that future taxable income will be available against which the Company can utilize the benefits. On January 1, 2025, an operating trust related to the 2024 arrangement with Perpetual Energy Inc. was dissolved, resulting in a capital loss of $926.1 million. No gain or loss was recorded for accounting purposes as the investment had nominal book value.

15. FINANCE EXPENSE

		December 31, 2025		December 31, 2024
Interest on bank debt (note 12)	**$**	**6,973**	$	5,897
Interest on term loan (note 13)		**2,300**		952
Interest on lease liabilities (note 7)		**316**		55
Total cash finance expense		**9,589**		6,904
Amortization of debt issue costs (note 13)		**170**		63
Accretion on decommissioning obligations (note 8a)		**1,104**		316
Accretion on other provision (note 8b)		**480**		93
Total non-cash finance expense		**1,754**		472
Finance expense	**$**	**11,343**	$	7,376

16. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital is compromised of the following:

		December 31, 2025		December 31, 2024
Accounts receivable	**$**	**3,856**	$	(15,519)
Prepaid expenses and deposits		**(247)**		(2,319)
Product inventory		**(586)**		(2,273)
Accounts payable and accrued liabilities		**(538)**		26,519
Other		**606**		—
Working capital acquired (note 4c)(1)		**—**		(4,707)
Working capital deficit	**$**	**3,091**	$	1,701
Related to operating activities		**(4,562)**		3,093
Related to investing activities		**7,653**		(1,392)
Working capital deficit	**$**	**3,091**	$	1,701

(1) Working capital acquired includes $6.4 million and $21.2 million from the initial fair value acquired in the Recombination Transaction with Perpetual and the acquisition of BMEC, respectively, adjusted for cash settlements to December 31, 2024.

17. FINANCIAL RISK MANAGEMENT

The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework and has implemented and monitors compliance with risk management policies.

The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adhere to market conditions and the Company's activities.

a) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from joint venture partners, oil and gas marketers and derivative contract counterparties.

Receivables from oil and gas marketers are normally collected on the 25th day of the month following sales. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large, well established purchasers. The Company has not experienced any significant collection issues with its oil and gas receivables.

The Company manages the credit exposure related to derivatives by engaging in risk management transactions with credit worthy counterparties that are members of its bank syndicate.

The combined carrying amount of cash and cash equivalents, accounts receivable and fair value of derivative assets at December 31, 2025 was $28.3 million (December 31, 2024 - $39.1 million), representing the Company's maximum credit exposure. The total amount of accounts receivable 90 days past due is $0.1 million at December 31, 2025 (December 31, 2024 - $0.1 million).

b) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meets its financial obligations as they become due. The Company's approach to managing liquidity to ensure that it will have sufficient sources of liquidity available, under both normal and stressed conditions by maintaining sufficient cash flow from other sources of capital consisting of cash from operating activities and available credit facilities.

c) Market risk

Market risk is the risk that changes in market prices such as foreign exchange rates, commodity prices, and interest rates will affect the Company's net income or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

The Company utilizes financial derivatives to manage market risks related to commodity prices. All such transactions are conducted in accordance with the Company's Risk Management Policy, which has been approved by the Board of Directors.

The following table summarizes the mark to market value of outstanding risk management contract assets (liabilities):

	December 31, 2025	December 31, 2024
Financial oil contracts	**$ 3,208**	$ 3,332
Financial natural gas contracts	**306**	6,625
Financial foreign exchange contracts	**1,987**	(2,735)
Risk management contracts	**$ 5,501**	$ 7,222
Risk management contracts – current asset	**$ 5,828**	$ 9,783
Risk management contracts – non-current asset	**—**	429
Risk management contracts – current liability	**(327)**	(2,765)
Risk management contracts – non-current liability	**—**	(225)
Risk management contracts	**$ 5,501**	$ 7,222

(1) Risk management contract assets and liabilities presented in the consolidated statement of financial position are shown net of offsetting assets or liabilities where the arrangement provides for the legal right and intention for net settlement exists.

The following table details the gains (losses) on risk management contracts:

	December 31, 2025	December 31, 2024
Unrealized loss on oil contracts	**$ (124)**	$ (4,550)
Unrealized loss on natural gas contracts	**(6,319)**	(3,508)
Unrealized gain (loss) on foreign exchange contracts	**4,722**	(4,194)
Unrealized loss on risk management contracts	**$ (1,721)**	$ (12,252)
Realized gain on oil contracts	**5,630**	397
Realized gain on natural gas contracts	**6,915**	2,338
Realized loss on foreign exchange contracts	**(1,174)**	(153)
Realized gain on risk management contracts	**$ 11,371**	$ 2,582
Gain (loss) on risk management contracts	**$ 9,650**	$ (9,670)

Oil risk management contracts

At December 31, 2025, the Company had in place the following oil commodity risk management contracts:

Commodity	Volumes Sold (bbl/d)	Term	Reference/Index	Contract Traded Bought/Sold	Average Price ($/bbl)
Crude Oil	1,500 bbl/d	Jan 2026 - Mar 2026	WTI (US$/bbl)	Swap - sold	$65.13
Crude Oil	500 bbl/d	Apr 2026 - Dec 2026	WTI (US$/bbl)	Swap - sold	$65.00
Crude Oil	1,000 bbl/d	Jan 2026 - Mar 2026	WCS Differential (US$/bbl)	Swap - sold	($12.50)
Crude Oil	1,500 bbl/d	Apr 2026 - Jun 2026	WCS Differential (US$/bbl)	Swap - sold	($12.22)
Crude Oil	2,000 bbl/d	Jul 2026 - Sep 2026	WCS Differential (US$/bbl)	Swap - sold	($12.20)
Crude Oil	1,000 bbl/d	Oct 2026 - Dec 2026	WCS Differential (US$/bbl)	Swap - sold	($12.50)

Subsequent to December 31, 2025, the Company entered into the following oil commodity risk management contracts:

Commodity	Volumes Sold (bbl/d)	Term	Reference/Index	Contract Traded Bought/Sold	Average Price ($/bbl)
Crude Oil	2,000 bbl/d	Feb 2026	WTI (US$/bbl)	Swap - sold	$62.94
Crude Oil	4,600 bbl/d	Mar 2026	WTI (US$/bbl)	Swap - sold	$69.06
Crude Oil	4,850 bbl/d	Apr 2026	WTI (US$/bbl)	Swap - sold	$67.42
Crude Oil	3,850 bbl/d	May 2026	WTI (US$/bbl)	Swap - sold	$64.43
Crude Oil	3,850 bbl/d	Jun 2026	WTI (US$/bbl)	Swap - sold	$64.19
Crude Oil	2,500 bbl/d	Apr 2026 - Jun 2026	WCS Differential (US$/bbl)	Swap - sold	($12.84)
Crude Oil	3,300 bbl/d	Jul 2026 - Sep 2026	WTI (US$/bbl)	Swap - sold	$61.29
Crude Oil	1,500 bbl/d	Jul 2026 - Sep 2026	WCS Differential (US$/bbl)	Swap - sold	($12.75)
Crude Oil	2,400 bbl/d	Oct 2026 - Dec 2026	WTI (US$/bbl)	Swap - sold	$63.53
Crude Oil	1,000 bbl/d	Oct 2026 - Dec 2026	WCS Differential (US$/bbl)	Swap - sold	($13.50)
Crude Oil	750 bbl/d	Jan 2027 - Dec 2027	WTI (US$/bbl)	Swap - sold	$66.50

As at December 31, 2025, if future WTI and WCS oil prices changed by $5.00 per bbl with all other variables held constant, net income and comprehensive income for the period would change by $1.4 million due to changes in the fair value of risk management contracts.

Natural gas risk management contracts

At December 31, 2025, the Company had in place the following natural gas commodity risk management contracts:

Commodity	Volumes Sold	Term	Reference/Index	Contract Traded Bought/Sold	Average Price ($/GJ)
Natural gas	5,000 GJ/d	Jan 2026 - Mar 2026	AECO 5A (CAD$/GJ)	Swap - sold	$4.00
Natural gas	5,000 GJ/d	Jan 2026 - Mar 2026	AECO 5A (CAD$/GJ)	Swap - bought	$3.31

Subsequent to December 31, 2025, the Company entered into the following gas commodity risk management contracts:

Commodity	Volumes Sold	Term	Reference/Index	Contract Traded Bought/Sold	Average Price ($/GJ)
Natural gas	5,276 GJ/d	Apr 2026 - Oct 2026	NYMEX (US$/GJ)	Swap - sold	$3.89

As at December 31, 2025, if future AECO gas prices changed by $0.25 per GJ with all other variables held constant, net income and comprehensive income for the year would change by nil due to changes in the fair value of risk management contracts.

Foreign exchange risk management contracts

At December 31, 2025, the Company had in place the following CAD/USD foreign exchange risk management contracts:

Fixed Contract	Notional amount	Term	Price (CAD$/US$)
Average rate forward (CAD$/US$)	$2,500,000 US$/month	Jan - Dec 2026	1.4066
Average rate forward (CAD$/US$)(1)	$5,000,000 US$/month	Jan - Dec 2026	1.3890

(1) At expiry on December 31, 2026 if the calendar 2027 forward strip is above 1.3890 CAD$/US$, Rubellite knocks into a $5.0 million US$/month contract at 1.3890 CAD$/US$ for the 2027 calendar year.

As at December 31, 2025, if future CAD$/US$ exchange rate changed by $0.05 with all other variables held constant, net income and comprehensive income for the year would change by $4.5 million due to changes in the fair value of risk management contracts.

Fair value of financial assets and liabilities

The Company's fair value measurements are classified into one of the following levels of the fair value hierarchy:

Level 1 – inputs represent unadjusted quoted prices in active markets for identical assets and liabilities. An active market is characterized by a high volume of transactions that provides pricing information on an ongoing basis.

Level 2 – inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly. These valuations are based on inputs that can be observed or corroborated in the marketplace, such as market interest rates or forecasted commodity prices.

Level 3 – inputs for the asset or liability are not based on observable market data.

The Company aims to maximize the use of observable inputs when preparing calculations of fair value. Classification of each measurement into the fair value hierarchy is based on the lowest level of input that is significant to the fair value calculation.

The fair value of cash, accounts receivable, prepaid deposits and accounts payable and accrued liabilities, which makes up working capital, approximate their carrying amounts due to their short terms to maturity. They are classified at amortized cost, level 1.

The fair value of bank debt and term loan approximate their carrying amounts due to time to maturity and current market rates for similar credit risk and terms. They are classified at amortized cost, level 2.

The fair value of risk management contracts are classified as fair value through profit or loss ("FVTPL"), level 2.

The fair value of financial assets and liabilities, excluding working capital, is attributable to the following fair value hierarchy levels:

				Fair value		
As of December 31, 2025	**Gross**	**Netting[(1)]**	**Carrying Amount**	**Level 1**	**Level 2**	**Level 3**
Financial assets						
Fair value through profit and loss						
Risk management contracts	$ 5,828	$ (327)	$ 5,501	$ —	$ 5,501	$ —
Financial liabilities						
Financial liabilities at amortized cost						
Bank debt	(92,583)	—	(92,583)	$ —	(92,583)	—
Term loan	(19,173)	—	(19,173)	$ —	(19,173)	—
Fair value through profit and loss						
Risk management contracts	(327)	327	—	—	—	—

(1) Risk management contract assets and liabilities presented in the consolidated statement of financial position are shown net of offsetting assets or liabilities where the arrangement provides for the legal right and intention for net settlement exists.

				Fair value		
As of December 31, 2024	**Gross**	**Netting[(1)]**	**Carrying Amount**	**Level 1**	**Level 2**	**Level 3**
Financial assets						
Fair value through profit and loss						
Risk management contracts	$ 12,216	$ (2,004)	$ 10,212	$ —	$ 10,212	$ —
Financial liabilities						
Financial liabilities at amortized cost						
Bank debt	(108,500)	—	(108,500)	—	(108,500)	—
Term loan	(19,027)	—	(19,027)	—	(19,027)	—
Fair value through profit and loss						
Risk management contracts	(4,994)	2,004	(2,990)	—	(2,990)	—

(1) Risk management contract assets and liabilities presented in the consolidated statement of financial position are shown net of offsetting assets or liabilities where the arrangement provides for the legal right and intention for net settlement exists.

d) Capital risk

The Company's strives to maintain a strong but flexible capital structure so as to maintain investor, creditor and market confidence and to sustain its future development to offset production declines. The Company manages its capital structure and adjusts it in light of changes in economic conditions. The Company's capital structure consists of shareholders' equity and working capital. The Company also has access to a $140.0 million (December 31, 2024 - $140.0 million) first lien credit facility with a syndicate of lenders, under which $46.0 million (December 31, 2024 - $30.4 million) was available at December 31, 2025. Draws on the credit facility were comprised of current borrowings of $92.6 million (December 31, 2024 - $108.5 million), letters of credit of $1.4 million (December 31, 2024 - $3.6 million). Cash and cash equivalents were nil (December 31, 2024 - $2.6 million).

18. KEY MANAGEMENT PERSONNEL

The Company has defined key management personnel as executive officers, as well as the Board of Directors, as they have the collective authority and responsibility for planning, directing and controlling the activities of the Company.

		December 31, 2025		December 31, 2024
Short-term compensation	$	4,169	$	2,797
Share based payments		2,865		2,194
Key management compensation	**$**	**7,034**	$	4,991

Prior to Recombination Transaction, short-term compensation for key management personnel was recognized through the MSA with Perpetual and recognized in general and administrative expense. Effective October 31, 2024, after the completion of the Recombination Transaction with Perpetual, compensation expense related to key management personnel was recorded directly within Rubellite's general and administrative expenses.

19. CONTRACTUAL OBLIGATIONS

As at December 31, 2025, the Company's minimum contractual obligations over the next four years and thereafter, excluding estimated interest payments, are as follows:

		2026		2027		2028		2029		Thereafter		Total
Contractual obligations												
Accounts payable and accrued liabilities	$	59,913	$	—	$	—	$	—	$	—	**$**	**59,913**
Term loan (note 13)		—		—		—		20,000		—		**20,000**
Bank debt (note 12)		—		92,583		—		—		—		**92,583**
Pipeline transportation commitment		2,580		1,264		564		564		2,819		**7,791**
Lease payments (note 7)		687		619		615		632		3,832		**6,385**
Other provision (note 8b)		3,750		3,750		3,750		3,750		1,191		**16,191**
Total	**$**	**66,930**	**$**	**98,216**	**$**	**4,929**	**$**	**24,946**	**$**	**7,842**	**$**	**202,863**

The Company has a drilling commitment on certain gross overriding royalty ("GORR") lands that must be fulfilled by September 28, 2026 (the "Commitment Date"). If WTI settles below $60.00 USD for a period of thirty consecutive days the agreement shall automatically extend for an additional 90 days. In the event the Company fails to fulfill the drilling commitment, the Company is required to pay $0.1 million per well not spud by the Commitment Date. As at December 31, 2025, the Company has drilled 29 (29.0 net) of the 59 (59.0 net) wells that are required to meet the drilling commitment. Subsequent to December 31, 2025, the Company has drilled an additional 5 (5.0 net) wells for a total of 25 (25.0 net) wells remaining to meet the drilling commitment.

RUBELLITE ENERGY

CORPORATE INFORMATION

DIRECTORS

Holly A. Benson
Independent Director[(1)(2)(3)]

Linda A. Dietsche
Independent Director[(1)(2)(3)]

Tamara L. MacDonald
Independent Director[(2)(3)(4)]

Geoffrey C. Merritt
Independent Director[(3)(4)(5)]

Susan L. Riddell Rose
President, Chief Executive Officer and Director

Ryan A. Shay
Vice President, Finance and Chief Financial Officer and Director

Bruce C. Shultz
Independent Director[(1)(3)(5)]

Steven L. Spence
Independent Director[(3)(4)(5)]

[(1)] Member of Audit Committee
[(2)] Member of Compensation Committee
[(3)] Member of Corporate Governance Committee
[(4)] Member of Environmental, Health & Safety Committee
[(5)] Member of Reserves Committee

OFFICERS

Susan L. Riddell Rose
President, Chief Executive Officer and Director

Ryan A. Shay
Vice President, Finance and Chief Financial Officer

Ryan M. Goosen
Vice President, Business Development and Land

Jeffrey R. Green
Vice President, Corporate and Engineering Services

Marcello M. Rapini
Vice President, Marketing

Karl H. Rumpf
Vice President, Exploration and New Ventures

HEAD OFFICE

3200, 605 – 5 Avenue SW
Calgary, Alberta Canada T2P 3H5

403.269.4400 PHONE
800.811.5522 TOLL FREE
403.269.4444 FAX
info@rubelliteenergy.com EMAIL
www.rubelliteenergy.com WEB

STOCK EXCHANGE LISTING | TSX | RBY

AUDITORS

KPMG LLP

BANKERS

ATB Financial
Bank of Montreal
The Bank of Nova Scotia
Shell Trading Canada

RESERVE EVALUATION CONSULTANTS

McDaniel & Associates Consultants Ltd.

REGISTRAR AND TRANSFER AGENT

Odyssey Trust Company