RUBELLITE ENERGY

2024 ANNUAL RESULTS

TO SHAREHOLDERS

Success in Rubellite's foundational organic growth strategy in the Clearwater formation and two strategic transactions propelled Rubellite to new heights in 2024.

Organic growth was driven by continued drilling success at Figure Lake where one rig operated continuously to drill 24 net development wells, while a second rig drilled 10 net additional step-out / delineation wells in the second half of the year. Sales production in greater Figure Lake grew through the drill bit to 4,953 bbl/d for the fourth quarter of 2024, up 67% relative to Q4 2023. In 2024, operational goals at Figure Lake were focused on maximizing the value of development locations with enhancements in well design and further de-risking the prospective location inventory through confirmatory step-out drilling. Positive advancement of these objectives led to: a refinement of the well design, grounding the field's primary development plan to a standard of 12 lateral legs with 33m inter-leg spacing and over 15,000 m of open hole per well; and the successful conversion of the vast majority of Rubellite's ~316 net heavy oil development locations[1] to high confidence locations, solidifying the foundation for Rubellite's longer term organic growth plan. Under a one-rig program drilling 18 wells per year, the location count at Figure Lake represents over 13 years of economic inventory. In addition, the new 5 MMcf/d natural gas sales plant and gas gathering infrastructure, commissioned in January 2025, is forecast to significantly reduce emissions and capture value through solution gas conservation and sales gas production.

The acquisition of Buffalo Mission Energy Corp. in August 2024 was a strategic step forward in Rubellite's growth, consolidation and portfolio enhancement strategy. The Frog Lake assets serve to plant a flag for Rubellite in the Cold Lake Oil Sands Area and increase the scale of Rubellite's operations, enhance funds flow, and add material and attractive drilling inventory, which in combination with our existing Clearwater assets, provides the basis for a strong growth profile with increased development inventory, exploration depth and exposure to large oil-in-place assets for future enhanced recovery potential. We are excited about applying our operational expertise to the Mannville Stack assets, partnering with the Frog Lake Energy Resources Corp. ("FLERC") on this development, and to building on our positive relationship with Frog Lake First Nation.

On November 1, 2024, Rubellite and Perpetual Energy Inc. recombined in an all-share transaction to create a stronger company with increased size and scale, enhanced financial liquidity and flexibility, and valuable synergies. Shareholders benefit by owning a larger, financially stronger company with increased and diversified free funds flow, and a well-defined organic growth profile. Rubellite Energy Corp. continues to execute on the heavy oil growth-focused business plan where multi-lateral horizontal drilling technology is being applied to unlock significant resource while generating attractive returns for shareholders. At the same time, the non-operated natural gas asset in the Deep Basin at Edson provides commodity and geographic diversification of funds flow and optionality to manage risk and capitalize on future opportunities.

Average heavy oil sales production grew 72% to 5,685 bbl/d for 2024 and the Company is poised for continued heavy oil production growth, exiting the year with December heavy oil sales of 8,083 bbl/d. Exit rate total sales production for the month of December averaged 12,027 boe/d, with natural gas and NGL sales from Edson contributing two months of net operating income to adjusted funds flow in the fourth quarter.

At year-end 2024, Rubellite's reserve-based net asset value ("NAV")[2] (discounted at 10%), is estimated at $601.1 million ($6.47 per share), up 26% year-over-year. With steady integration of the strategic transactions, Rubellite is poised to convert our deep inventory of opportunities to continue to grow production, reserves, adjusted funds flow and value.

Our focus remains on continued growth by advancing the primary development and enhanced recovery in our core Clearwater and Mannville Stack assets, and evaluating our portfolio of exploration prospects, while in parallel pursuing new exploration ideas and potential consolidation opportunities in these two attractive play trends. For 2025, Rubellite's strategic priorities are to:

1. Optimize Development of Base Assets for Heavy Oil Growth;
2. Drive Top Quartile Capital Efficiencies;
3. Advance Enhanced Oil Recovery on Core Assets;
4. De-risk Exploration Prospects and Expand Portfolio;
5. Grow Land Base and Prospect Inventory for Chosen Play Strategies;
6. Increase Reserve-Based Net Asset Value and Potential Asset Value per Share;
7. Re-Establish Pristine Balance Sheet and Manage Risk; and
8. Drive Operational Excellence and Capture Cost Efficiencies.

Our many and varied accomplishments in 2024 are the product of Rubellite's hard-working and talented team. In particular, the special committee work of the independent directors of both Rubellite and Perpetual was extensive and complex, and we are grateful for their deep and ongoing commitment. We remain in steadfast pursuit of our ultimate goal to create exceptional value for our shareholders, and while doing so, to benefit our many stakeholders. With our culture of accountability, an entrepreneurial spirit, and perseverance that defines us, we look forward to continuing to build this Clearwater and Mannville Stack-focused junior explorer and producer at a unique time when the communities where we live and work, our province, Canada and the world truly need our energy and our ingenuity.

Susan Riddell Rose

SUE RIDDELL ROSE
President and Chief Executive Officer

March 10, 2025

(1) See "Estimated Drilling Locations" on page 31 in this Annual Results report.
(2) See "Net Asset Value" on page 8 in this Annual Results report.

ANNUAL FINANCIAL AND OPERATING HIGHLIGHTS

($ thousands, except as noted)	2024	2023	2022
Financial			
Oil revenue	**168,384**	88,968	54,491
Net income and comprehensive income	**49,973**	18,561	24,605
Per share – basic[1]	**0.73**	0.31	0.47
Per share – diluted[1]	**0.72**	0.30	0.47
Total Assets	**562,612**	271,153	204,030
Cash flow from operating activities	**95,788**	55,391	23,870
Adjusted funds flow, including transaction costs[2][6]	**93,777**	54,156	23,036
Per share – basic[1][2]	**1.37**	0.90	0.44
Per share – diluted[1][2]	**1.35**	0.89	0.44
Adjusted funds flow, before transaction costs[2][6]	**100,010**	54,304	23,036
Per share – basic[1][2]	**1.46**	0.90	0.44
Per share – diluted[1][2]	**1.43**	0.89	0.44
Q4 annualized adjusted funds flow[2][11]	**143,420**	68,280	32,580
Net debt to Q4 annualized adjusted funds flow ratio[2][11]	**1.1**	0.7	0.9
Net debt (asset)[2]	**154,020**	50,984	28,228
Capital expenditures[2]			
Capital expenditures, including land, corporate and other[2]	**108,906**	71,530	94,207
Acquisitions[8][9]	**179,247**	33,173	—
Proceeds on dispositions[10]	**—**	(7,990)	—
Capital expenditures, after acquisition and dispositions[2]	**288,153**	96,713	94,207
Wells Drilled[3] – gross (net)	**46 / 41.5**	30 / 29.5	45 / 39.5
Common shares outstanding[1] *(thousands)*			
Weighted average – basic	**68,667**	60,346	52,093
Weighted average – diluted	**69,716**	61,075	52,471
End of period	**93,044**	62,456	54,826
Operating			
Heavy oil (bbl/d)[4]	**5,685**	3,302	1,670
Natural gas (MMcf/d)	**3.6**	—	—
NGL (bbl/d)[5]	**69**	—	—
Daily average sales production (boe/d)	**6,349**	3,302	1,670
Average prices			
West Texas Intermediate ("WTI") ($US/bbl)	**75.72**	77.62	94.22
Western Canadian Select ("WCS") ($CAD/bbl)	**83.52**	79.46	98.49
AECO 5A Daily Index ($CAD/Mcf)	**1.46**	2.64	5.34
Rubellite average realized prices[2][7]			
Oil ($/bbl)	**78.92**	73.82	89.38
Natural gas ($/Mcf)	**2.01**	—	—
NGL ($/bbl)	**61.32**	—	—
Average realized price[2] ($/boe)	**72.46**	73.82	89.38
Average realized price, after risk management contracts[2] ($/boe)	**73.57**	73.56	67.82

(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 Measures" contained in this Annual Results report.
(3) Well count reflects wells rig released during the period.
(4) Conventional heavy oil sales production excludes tank inventory volumes.
(5) Liquids means oil, condensate, ethane 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 Acquisition.
(7) Before risk management contracts; supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(8) The Recombination Transaction with Perpetual 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, prior to purchase price adjustments.
(9) Clearwater acquisition closing on November 8, 2023 for cash consideration of $34.0 million, prior to purchase price adjustments.
(10) Royalty sale closed on December 8, 2023 for cash consideration of $8.0 million, prior to purchase price adjustments.
(11) Based on fourth quarter annualized adjusted funds flow before transaction costs relative to year-end net debt. Non-GAAP financial measure and ratio.

ADVISORIES

This letter to shareholders, 2024 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 25 to 28, "Management's Discussion and Analysis – FORWARD-LOOKING INFORMATION" on pages 30 and 31.

In addition to the disclosure set out in the Company's Management's Discussion and Analysis for the period ended December 31, 2024 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.

This Annual Results report 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."

2024 STRATEGIC TRANSACTIONS

Buffalo Mission Acquisition

On August 2, 2024, Rubellite closed the acquisition of Buffalo Mission Energy Corp. ("Buffalo Mission" or "BMEC") (the "BMEC Acquisition"), a private Mannville Stack-focused heavy oil producer in the Frog Lake area. The total consideration paid by Rubellite for BMEC was $96.6 million, inclusive of $23.5 million of BMEC's 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. The BMEC Acquisition was funded through an expanded credit facility which increased from $60.0 million to $100.0 million, a $20.0 million bank syndicate term loan which was set to mature on December 15, 2024, and a new five year term loan ("Term Loan") placed, directly or indirectly, with certain directors and officers of Rubellite and the Company's significant shareholder for $20.0 million which bears interest at 11.5%.

Recombination Transaction

On October 31, 2024, the Company, Rubellite Energy Inc., and Perpetual Energy Inc. ("Perpetual") completed a recombination transaction by way of an arrangement under Section 193 of the Business Corporations Act (Alberta) (the "Recombination Transaction")(1). In accordance with the Recombination Transaction, (i) holders of common shares of Rubellite Energy Inc. received one (1) common share of the Company for every one (1) common share of Rubellite Energy Inc. held, (ii) holders of common shares of Perpetual received one (1) common share of the Company for every five (5) Perpetual common 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 share. At closing, shareholders of Rubellite Energy Inc. held 67.6 million shares (72.7%), Perpetual shareholders held 13.7 million shares (14.8%) and holders of Perpetual senior notes held the remaining 12.5% of the Company. The bank syndicate term loan was repaid in full in conjunction with the closing of the Recombination Transaction.

2024 FOURTH QUARTER AND ANNUAL FINANCIAL AND OPERATING HIGHLIGHTS

- Rubellite delivered record fourth quarter conventional heavy oil sales production of 7,754 bbl/d that exceeded guidance and was 30% higher than the third quarter of 2024 (Q3 2024 - 5,954 bbl/d) and 84% above the fourth quarter of 2023 (Q4 2023 - 4,209 bbl/d). Fourth quarter total sales production of 10,386 boe/d (77% heavy oil and NGL) was up 74% and 147% from the third quarter of 2024 and fourth quarter of 2023. Production growth relative to the third quarter of 2024 was driven by the successful drilling program at Figure Lake, the full quarter impact of the BMEC Acquisition, and two months of operations at East Edson following the closing of the Recombination Transaction, which added an average of 2,627 boe/d of sales volumes (14.1 MMcf/d of conventional natural gas and 275 bbl/d of NGL). 2024 sales production was 6,349 boe/d, an increase of 92% year-over-year, and included 5,685 bbl/d of heavy oil sales production, up 72% from 3,302 bbl/d in 2023.

- Exit rate sales production for the month of December averaged 12,027 boe/d (8,083 bbl/d heavy oil), exceeding previous production guidance ranges of 11,300 to 11,800 boe/d of total sales (7,500 to 7,900 bbl/d heavy oil).

- Exploration and development capital expenditures(2) totaled $34.4 million for the fourth quarter bringing expenditures to $101.7 million in 2024. Fourth quarter spending included costs to drill, complete, equip and tie-in nine (9.0 net) multi-lateral horizontal development / step-out delineation wells at Figure Lake, five (3.0 net) multi-lateral horizontal development wells at Frog Lake and one (1.0 net) exploratory horizontal four-leg multi-lateral well at Calling Lake / Nixon. Included in fourth quarter development capital spending was $1.8 million for the Figure Lake gas conservation project. During 2024, the Company spent $101.7 million, before land and other corporate spending, primarily related to the drilling, completion, equipping and tie-in of thirty four (34.0 net) multi-lateral horizontal wells at Figure Lake, ten (5.5 net) multi-lateral horizontal wells at Frog Lake, drilling and coring of one (1.0 net) vertical stratigraphic evaluation well and included the one (1.0 net) Calling Lake / Nixon evaluation well drilled in the fourth quarter. Full year facilities spending included $7.2 million related to the construction of the Figure Lake gas plant and pipeline tie-ins for solution gas conservation.

- Land and seismic purchases were $1.0 million in the fourth quarter of 2024 to acquire 24.0 net sections of land, with total land purchases in 2024 of $4.1 million to acquire 41.5 net sections of land. Corporate spending for 2024 was $3.1 million and related to leasehold improvements for the shared office space under the Management and Operating Services Agreement ("MSA") prior to the Recombination Transaction.

- Adjusted funds flow before transaction costs(2) in the fourth quarter was $35.9 million ($0.41 per share) compared to the third quarter of $25.0 million or $0.37/share (Q4 2023 - $17.1 million or $0.27 per share). Adjusted funds flow after transaction costs(2) for the three and twelve months ended December 31, 2024 were $31.6 and $93.8 million (three and twelve months ended December 31, 2023 - $16.9 and $54.2 million).

- Cash costs(2) were $18.6 million or $19.45/boe in the fourth quarter of 2024 (Q3 2024 - $13.5 million or $24.72/boe; Q4 2023 - $7.9 million or $20.49/boe). Cash costs for full year 2024 were $50.4 million ($21.68/boe) compared to $25.7 million ($21.29/boe) in 2023.

- Net income was $26.7 million ($0.31 per share) in the fourth quarter of 2024 (Q4 2023 - $9.5 million; $0.15 per share) and $50.0 million ($0.73 per share) for full year 2024 (2023 - $18.6 million; $0.31 per share).

- As at December 31, 2024, net debt(2) was $154.0 million, an increase from $51.0 million as at December 31, 2023 as a result of the BMEC Acquisition during the third quarter of 2024 and capital expenditures of $108.9 million in 2024 which exceeded adjusted funds flow of $93.8 million. The Recombination Transaction did not have a material impact on net debt as consideration was primarily from the issuance of Rubellite shares with minimal net debt assumed. At December 31, 2024, net debt to Q4 2024 annualized adjusted funds flow before transaction costs(2) was 1.1 times.

- Rubellite had available liquidity(2) at December 31, 2024 of $30.4 million, comprised of the $140.0 million borrowing limit of Rubellite's first lien credit facility, less current bank borrowings of $108.5 million, outstanding letters of credit of $3.6 million offset by cash and cash equivalents of $2.6 million.

- Rubellite's reserve-based net asset value ("NAV")(2) (discounted at 10%) at year-end 2024 is estimated at $601.1 million ($6.47 per share) as compared to $321.3 million ($5.14 per share) at year-end 2023.

(1) See "Advisories" on page 3 of this Annual Results report.
(2) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures" in this Annual Results report.

YEAR-END 2024 RESERVES HIGHLIGHTS

As presented in the McDaniel Report[(1)], Rubellite's proved plus probable reserves at year-end 2024 are 53.0 MMboe, comprised of 51% heavy crude oil (2023 – 16.0 MMboe, 93% heavy crude oil). The Company's proved plus probable reserves grew by 37.0 MMboe (231%) year-over-year, replacing production of 2.3 MMboe by 17 times.

Growth in year-end 2024 reserves is attributed to the successful drilling program at Figure Lake and Edwand and to acquisitions which added 32.0 MMboe to the year end proved plus probable reserves balance. Acquisitions included the heavy oil producing property at Frog Lake, prospective land in Ukalta and Figure Lake, and the addition of assets in West Central Alberta through the Recombination Transaction with Perpetual which accounted for 25.0 MMboe of the proved plus probable reserve acquisition volumes. Organic growth through drilling in the Clearwater play alone added 8.2 MMboe, replacing production by 3.5 times.

Other highlights from the McDaniel Report[(1)] include:

- Total proved reserves were 32.7 MMboe at year-end 2024, representing 62% of the Company's proved plus probable reserves (2023 – 62%) and a 228% increase over 2023 (10.0 MMboe).
- Total proved developed producing reserves were 17.7 MMboe at year-end 2024, an increase of 230% over year-end 2023 and representing 33% of the Company's proved plus probable reserves (2023 - 5.3 MMboe; 33% of proved plus probable reserves).
- Proved plus probable producing reserves were 23.0 MMboe at December 31, 2024, representing 43% of total proved plus probable reserves (2023 – 7.1 MMboe; 44% of proved plus probable reserves).
- Rubellite's total exploration, development and acquisition capital spending of $285.1 million (excluding $3.1 million of corporate capital) resulted in total proved plus probable additions of 39.3 MMboe and including a change in future development capital of $291.2 million results in Finding Development and Acquisition ("FD&A") costs of $14.66/boe.
- Strong annual operating netback[(4)] of $49.60/boe and relatively low cost reserve additions delivered a total proved plus probable recycle ratio of 3.4 times.
- The McDaniel Report includes a total of 200 gross (152.7 net) booked undeveloped drilling locations, which are comprised of 131 (102.6 net) proved undeveloped and 69 (50.1 net) probable undeveloped locations. Of these, 99 gross (96.2 net) are in the greater Figure Lake area with 66 (65.6 net) that are proved undeveloped and 33 (30.6 net) probable undeveloped.
- Rubellite has made advances in optimizing well configuration throughout 2024 to maximize net present value and better exploit the Clearwater formation in Figure Lake and Edwand. Nine gross (9.0 net) 33 meter inter-leg spaced pilot wells ("33m wells") were drilled in 2024 to assess this exploitation technique (compared to typical 50 meter inter-leg spaced wells ("50m wells"). Results to date (3-4 months of production history) indicate a 1:1 scaling for rate on the additional meters drilled, while maintaining the same areal footprint of a 50 meter well. This exploitation strategy maintains future well placement and location count, while increasing rates, reserves and net present values. All future Figure Lake development locations reflected in the McDaniel Report are booked as 33 meter wells and McDaniel has made adjustments to the year-end 2024 type curve to reflect this well design change.
- The Figure Lake Tier 1 type curve[(2)] total proved plus probable reserves increased 7.7% to 140 Mboe per well (2023 - 130 Mboe per 50m well) with future development costs of $2.5 million per 33m well (2023 - $1.9 million per 50m well). The Figure Lake type curve IP30 rate increased to 177 bbl/d from the year end 2023 Tier 1 50m type curve IP30 of 119 bbl/d due to the positive performance from 2024 wells including results from both the 50m and 33m inter-leg spacing wells.
- All abandonment, decommissioning and reclamation obligations are included in the McDaniel Report, consistent with year-end 2023. 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.
- Based on the three consultant average price (McDaniel, GLJ, Sproule) 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 $721.5 million (2023 – $322.1 million). The 124% NPV10 increase is related primarily to acquisitions, as well as organic growth in Figure Lake.
- Rubellite's undeveloped land at year-end 2024, was independently assessed in the Seaton-Jordan Report[(3)], at $48.8 million, an increase of 19.9% from $40.7 million at year-end 2023.
- Based on the Consultant Average Price Forecast, Rubellite's reserve-based net asset value ("NAV")[(4)] (discounted at 10%) at year-end 2024, inclusive of the independent assessment of undeveloped land and net of the Company's year-end 2024 total net debt[(4)] and other obligations, which includes $154.0 million of net debt, $19.9 million of other obligations and an estimated mark-to-market value of financial hedges relative to the Consultant Average Price Forecast as of January 1, 2025 of $4.7 million, is estimated at $601.1 million ($6.47 per share) as compared to $321.3 million ($5.14 per share) at year-end 2023.

(1) "McDaniel Report" means the independent engineering evaluation of the Company's heavy crude oil, conventional natural gas and NGL reserves, prepared by McDaniel & Associates Consultants Ltd. ("McDaniel") with an effective date of December 31, 2024 and a preparation date of March 10, 2025.

(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 Annual Information Form 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, 2024 in a report dated February 20, 2025 (the "Seaton-Jordan Report"). The estimate 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 proved and/or probable undeveloped reserves have been booked.

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

YEAR-END 2024 RESERVES DATA

The reserves data set forth below is based upon the report of McDaniel & Associates Consultants Ltd. ("McDaniel") dated effective December 31, 2024, with a preparation date of March 10, 2025 (the "McDaniel Report"). 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 three consultant (McDaniel, GLJ Ltd., Sproule Associates Limited) average price forecasts (the "Consultant Average Price Forecast") as outlined in the table below entitled "Price Forecast". See "Reserves Data and Other Metrics" for additional cautionary language, explanations and discussion and "Forward Looking Information and Statements" 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	7,932	889	53,021	17,659
Developed Non-producing	110	2	176	141
Undeveloped	7,836	684	38,222	14,890
Total Proved ("1P")(1)	**15,878**	**1,576**	**91,419**	**32,690**
Total Probable	10,976	884	50,749	20,318
Total Proved plus Probable ("2P")(1)	**26,854**	**2,460**	**142,167**	**53,009**

(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, 2024, 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	376,886	339,307	303,259	274,457	251,722
Developed Non-producing	4,147	3,887	3,623	3,383	3,171
Undeveloped	260,496	184,411	133,496	97,998	72,317
Total Proved(1)	**641,529**	**527,604**	**440,378**	**375,838**	**327,211**
Total Probable	568,898	387,221	281,160	214,595	170,200
Total Proved plus Probable(1)	**1,210,427**	**914,825**	**721,538**	**590,433**	**497,411**

(1) May not add due to rounding.
(2) Based on the McDaniel Report and Consultant Average Price Forecast. For detailed price forecast information, please see the Company's Annual Information Form available under the Company's profile on SEDAR+ at www.sedarplus.ca.

Reserves Reconciliation

The following reconciliation of Rubellite's gross reserves compares changes in the Company's independently evaluated reserves as at December 31, 2024, relative to the reserves as at December 31, 2023:

		Mboe	
	Total Proved	**Total Probable**	**Total Proved+Probable**
December 31, 2023	9,957	6,058	16,014
Extensions and Improved Recoveries	4,823	3,381	8,204
Discoveries	—	—	—
Technical Revisions	27	(999)	(972)
Acquisitions	20,180	11,867	32,047
Dispositions	—	—	—
Production	(2,324)	—	(2,324)
Economic Factors	27	12	39
December 31, 2024(1)	**32,690**	**20,318**	**53,009**

(1) May not add due to rounding.

The 2024 drilling program resulted in proved plus probable producing extensions of 2,532 Mboe and proved plus probable undeveloped extensions of 5,672 Mboe attributed to the addition 50 (48.2 net) undeveloped locations.

Forty percent of the technical revisions in proved plus probable reserves were driven by changes to the corporate development plan. With a strategic focus to develop the core properties of Figure Lake, and the recently acquired Frog Lake asset, several lower tier locations in Ukalta and Marten Hills were removed from reserves. The remaining technical revisions (representing a minor reduction of 3.5% on the opening balance) are a result of the aggregate changes to all base producing wells and some non-producing re-activations that were removed from proved plus probable reserves.

Material changes in reserves in all categories resulted from three acquisitions: Assets acquired in Frog Lake through the BMEC Acquisition added 5,925 Mboe; the Recombination Transaction with Perpetual added 24,964 Mboe; and a land acquisition in the Figure Lake and Ukalta properties added 1,158 Mboe.

Finding & Development Costs

	2024			2023		
($ thousands, except as noted)	**PDP**	**1P**	**2P**	PDP	1P	2P
Exploration and Development Expenditures	**95,373**	**95,373**	**95,373**	71,530	71,530	71,530
Acquisitions (net of Dispositions)	**189,683**	**189,683**	**189,683**	25,184	25,184	25,184
Change in Future Development Capital ("FDC")	**—**	**187,586**	**291,180**	—	32,390	39,613
Exploration and Development	**—**	**77,762**	**121,363**	—	17,091	18,947
Acquisitions (net of Dispositions)	**—**	**109,824**	**169,817**	—	15,299	20,666
Reserves Additions with Revisions and Economic Factors (Mboe)	**14,636**	**25,058**	**39,319**	3,552	5,082	6,943
Exploration and Development (Mboe)	**3,231**	**4,877**	**7,271**	2,954	3,890	5,018
Acquisitions (net of Dispositions) (Mboe)	**11,405**	**20,180**	**32,047**	598	1,192	1,925

	2024			2023		
	PDP	**1P**	**2P**	PDP	1P	2P
Finding & Development Costs(1) ("F&D")($ per boe)	29.52	35.50	29.81	24.22	22.78	18.03
Finding, Development & Acquisition Costs(1) ("FD&A")($ per boe)	19.48	18.86	14.66	27.23	25.40	19.63
Recycle Ratio (FD&A)	2.5	2.6	3.4	2.0	2.1	2.7
Reserve Replacement	6.3	10.8	16.9	2.9	4.2	5.8

(1) Includes change in future development capital ("FDC") for 1P and 2P.

Rubellite's total 2024 exploration, development and land capital spending was $105.8 million of which $10.4 million was spent at Frog Lake following the closing of the Frog Lake acquisition. Rubellite's 2024 acquisitions expenditure was $179.2 million. All Frog Lake reserve changes, including results of the post acquisition drilling program are included as acquisition additions; therefore, to align capital and reserves for the purposes of F&D calculations, capital spent at Frog Lake post acquisition has been included with acquisition expenditures, resulting in adjusted exploration and development expenditures (including land) of $95.4 million and adjusted acquisition expenditures of $189.7 million.

Exploration, development and land expenditures of $95.4 million, including a change in FDC of $121.4 million for newly recognized drilling locations that includes $0.5 million per proved and probable undeveloped location to reflect the development plan change to the 33 meter inter-leg spacing well design for all future drilling locations at Figure Lake, resulted in total proved plus probable additions of 7.3 MMboe for year end 2024.

Acquisition expenditures of $189.7 million and the change in FDC related to acquisitions of $169.8 million resulted in total proved plus probable additions of 32.0 MMboe.

Combined, total proved plus probable additions of 39.3 MMboe and total capital of $576.2 million result finding, development and acquisition costs, including changes in FDC, of $14.66/boe. Based on 2024 operating netbacks of $49.60/boe, the total proved plus probable recycle ratio is 3.4 times.

As a result of the well design change and positive results from the 2024 drilling program (on both 33m and 50m inter-leg spaced wells), the McDaniel 33m Tier 1 Type Curve(1) 2P reserves increased by 8% and the IP30 rate was increased by 48% relative to the McDaniel 50m Type Curve(1) in the 2023 McDaniel Report. Capital per location was increased by $0.5 million (~27%) per proved and probable undeveloped location relative to the 50 meter spacing well design in the 2023 McDaniel Report, as the new well design has 5,000m additional horizontal length.

Excluding the change in FDC, the finding and development costs in 2024 for Clearwater heavy oil were $29.52/boe on a PDP basis, $25.62/boe on a P+PDP basis, and $19.45/boe on a P+PDP basis using drill bit capital and reserves only (all capital and reserves related to wells drilled in 2024 including drilling, completions, pad-site construction, and associated facilities). Based on 2024 heavy oil netbacks of $54.44/boe, the PDP, P+PDP and P+PDP (using drill bit capital and reserves only) recycle ratios are 1.8 times, 2.1 times and 2.8 times respectively.

(1) Type curve assumptions are based on the Total Proved plus Probable Undeveloped reserves contained in the McDaniel Reserve Report as disclosed in the Company's Annual Information Form which will be available under the Company's profile on SEDAR+ at www.sedarplus.ca. "McDaniel" means McDaniel & Associates Consultants Ltd. independent qualified reserves evaluators. "McDaniel Reserve 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, 2024 and a preparation date of March 10, 2025. See "Estimated Drilling Locations. Type curve assumptions for the 50 meter spacing well design are based on the Total Proved plus Probable Undeveloped reserves contained in the 2023 McDaniel Reserve Report as disclosed in the Company's 2023 Annual Information Form.

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, 2024[2]

				Discounted at
($ millions, except as noted)	**Undiscounted**	**5%**	**10%**	**15%**
Developed reserves[3]	549.4	466.0	402.5	356.2
Undeveloped reserves[3]	665.7	453.5	323.7	238.9
Fair market value of undeveloped land[4]	48.8	48.8	48.8	48.8
Net debt[1][2]	(154.0)	(154.0)	(154.0)	(154.0)
Other provision[2]	(19.9)	(19.9)	(19.9)	(19.9)
NAV[1]	**1,090.0**	**794.4**	**601.1**	**470.0**
Common shares outstanding (million)[5]	92.9	92.9	92.9	92.9
NAV per share ($/share)[1][5][6]	**$ 11.73**	**$ 8.55**	**$ 6.47**	**$ 5.06**

(1) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(2) Financial information is per Rubellite's 2024 audited consolidated financial statements.
(3) Proved plus Probable developed and proved plus probable undeveloped reserve values per the McDaniel Report dated December 31, 2024 with a preparation date of March 10, 2025, 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, 2024.

OUTLOOK AND GUIDANCE

Rubellite plans to operate one rig drilling continuously in the Greater Figure Lake area and a second rig drilling continuously at Frog Lake, throughout 2025. Exploration and development capital spending for the first quarter of 2025 is expected to be approximately $22 to $24 million, including the drilling, completion, equipping and tie-in of: four (4.0 net) multi-lateral horizontal Clearwater development wells at Figure Lake / Edwand; six (4.5 net) multi-lateral horizontal development wells in the Waseca formation at Frog Lake (three upcoming Q1 drills and one upcoming Q2 well will be at 100% working interest as Frog Lake Energy Resources Corp. ("FLERC") has elected gross overriding royalty positions on those wells); one (0.3 net) well at Marten Hills to initiate waterflood; and one (1.0 net) exploration evaluation well. First quarter 2025 capital spending will further include approximately $1.5 million to complete the initial phase of the gas conservation project at Figure Lake and expand the gas gathering system. In West Central Alberta, $0.9 million is forecast to participate with its joint venture partner at East Edson in preparatory surface work for a four (2.0 net) well drilling program in the second half of 2025 to offset natural declines in the Company's liquids-rich natural gas production.

Factoring in recent drilling performance and type curve expectations at Figure Lake/Edwand and at Frog Lake, heavy oil sales volumes are expected to grow approximately 3% to 6% from the fourth quarter of 2024 to average between 8,000 - 8,200 bbl/d in Q1 2025. Total production sales volumes for the first quarter of 2025 are expected to be 12,000 to 12,200 boe/d (70% heavy oil and NGL).

For full year 2025, Rubellite expects to spend a total of $95 to $110 million. Planned capital activity at the low end of the spending guidance range includes: drilling eighteen (18.0 net) multi-lateral development / step-out wells in the Greater Figure Lake area; drilling twenty-four (14.0 net) multi-lateral development / step-out wells in the Frog Lake area; approximately $2.6 million to expand the Figure Lake gas conservation project including additional plant optimization and pipeline tie-ins; drilling one (0.3 net) well at Marten Hills to initiate waterflood; participation in the drilling of four (2.0 net) wells at East Edson; and spending to continue to evaluate additional heavy oil exploration prospects, and to advance enhanced oil recovery ideas in the Clearwater. If market conditions warrant, the Company would look to expand its planned activity levels to the high end of the spending guidance range which would further grow production levels into 2026.

Corresponding heavy oil sales volumes are expected to grow 44% to 48% year-over-year to average between 8,200 - 8,400 bbl/d in 2025. Total production sales volumes, including natural gas and NGL volumes at East Edson and solution gas sales at Figure Lake, are forecast to average 12,200 - 12,400 boe/d in 2025.

Forecast activity will be funded from adjusted funds flow[1], with excess free funds flow applied to reduce net debt[1].

Rubellite has made provisions to potentially add a second drilling rig to the Greater Figure Lake Clearwater drilling program early in the third quarter of 2025, subject to a favorable commodity price outlook in the second quarter of 2025.

Rubellite will continue to address end of life ARO, with total abandonment and reclamation expenditures of approximately $1.9 million planned for 2025. The Company's area-based mandatory spending requirement for 2025 is $1.7 million, as calculated by the Alberta Energy Regulator ("AER").

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

Capital spending and drilling activity for the first quarter and full year 2025 is summarized in the table below:

	Q1 2025(1) ($ millions)	# of wells (gross/net)	2025(1) ($ millions)	# of wells (gross/net)
Figure Lake		4 / 4.0		18 / 18.0
Frog Lake		6 / 4.5		24 / 14.0
Marten Hills		1 / 0.3		1 / 0.3
East Edson		0 / 0.0		4 / 2.0
Exploration(2)		1 / 1.0		4 / 3.5
Total(1)	**$22 - $24 million**	**12 /9.8**	**$95 - $110 million**	**51 / 37.8**

(1) Excludes abandonment and reclamation spending and acquisitions or land expenditures, if any.
(2) Includes wells at Figure Lake and Frog Lake targeting secondary exploratory zones.

Rubellite's guidance for first quarter and full year 2025 is presented in the table below:

	Q1 2025 Guidance	2025 Guidance
Sales Production (boe/d)	12,000 -12,200	12,200 - 12,400
Production mix (% oil and liquids)(1)	70%	70%
Heavy Oil Production (bbl/d)	8,000 - 8,200	8,200 - 8,400
Exploration and Development spending ($ millions)(2)(3)	$22 - $24	$95 - $110
Multi-lateral development / step-out wells (net)(4)	11 (8.8)	47 (34.3)
Exploration wells (net)(5)	1 (1.0)	4 (3.5)
Heavy oil wellhead differential ($/bbl)(2)	$5.00 - $5.50	$5.00 - $5.50
Royalties (% of revenue)(2)	13% - 14%	13% - 14%
Production and operating costs ($/boe)(2)	$7.00 - $7.75	$7.00 - $7.75
Transportation costs ($/boe)(2)	$5.50 - $6.00	$5.50 - $6.00
General and administrative costs ($/boe)(2)	$3.00 - $3.50	$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 land and acquisition spending, if any.
(4) Includes three step-out delineation wells at Figure Lake.
(5) Includes wells at Figure Lake and Frog Lake targeting secondary exploratory zones.

FOURTH QUARTER AND ANNUAL FINANCIAL AND OPERATING HIGHLIGHTS

	Three months ended December 31,		Twelve months ended December 31,	
	2024	2023	**2024**	2023
Financial				
Oil revenue	**59,081**	27,224	**168,384**	88,968
Net income and comprehensive income	**26,747**	9,523	**49,973**	18,561
Per share – basic(1)	**0.31**	0.15	**0.73**	0.31
Per share – diluted(1)	**0.30**	0.15	**0.72**	0.30
Total Assets	**562,612**	271,153	**562,612**	271,153
Cash flow from operating activities	**39,402**	18,963	**95,788**	55,391
Adjusted funds flow, after transaction costs(2)(6)	**31,632**	16,923	**93,777**	54,156
Per share – basic(1)(2)	**0.36**	0.27	**1.37**	0.90
Per share – diluted(1)(2)	**0.36**	0.27	**1.35**	0.89
Adjusted funds flow, before transaction costs(2)(6)	**35,855**	17,070	**100,010**	54,304
Per share – basic(1)(2)	**0.41**	0.27	**1.46**	0.90
Per share – diluted(1)(2)	**0.40**	0.27	**1.43**	0.89
Q4 annualized adjusted funds flow(2)(11)	**143,420**	68,280	**143,420**	68,280
Net debt to Q4 annualized adjusted funds flow ratio(2)(11)	**1.1**	0.7	**1.1**	0.7
Net debt (asset)(2)	**154,020**	50,984	**154,020**	50,984
Capital expenditures(2)				
Capital expenditures, including land, corporate and other(2)	**35,537**	26,320	**108,906**	71,530
Acquisition(8)(9)	**68,467**	33,173	**179,247**	33,173
Proceeds on disposition(10)	**—**	(7,990)	**—**	(7,990)
Capital expenditures, after acquisition and dispositions(2)	**104,004**	51,503	**288,153**	96,713
Wells Drilled(3) – gross (net)	**15 / 13.0**	11 / 11.0	**46 / 41.5**	30 / 29.5
Common shares outstanding(1) *(thousands)*				
Weighted average – basic	**87,655**	62,440	**68,667**	60,346
Weighted average – diluted	**88,546**	62,958	**69,716**	61,075
End of period	**93,044**	62,456	**93,044**	62,456
Operating				
Heavy Oil (bbl/d)(4)	**7,754**	4,209	**5,685**	3,302
Natural gas (Mcf/d)	**14,140**	—	**3,570**	—
NGLs (bbl/d)(5)	**275**	—	**69**	—
Daily average sales production (boe/d)	**10,386**	4,209	**6,349**	3,302
Average prices				
West Texas Intermediate ("WTI") ($US/bbl)	**70.27**	78.32	**75.72**	77.62
Western Canadian Select ("WCS") ($CAD/bbl)	**80.74**	76.84	**83.52**	79.46
AECO 5A Daily Index ($CAD/Mcf)	**1.48**	2.30	**1.46**	2.64
Rubellite average realized prices(2)(7)				
Oil ($/bbl)	**76.97**	70.31	**78.92**	73.82
Natural gas ($/Mcf)	**2.01**	—	**2.01**	—
NGL ($/bbl)	**61.32**	—	**61.32**	—
Average realized price(2) ($/boe)	**61.83**	70.31	**72.46**	73.82
Average realized price, after risk management contracts(2) ($/boe)	**65.14**	72.12	**73.57**	73.56

(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 Measures" contained in this Annual Results report.
(3) Well count reflects wells rig released during the period.
(4) Conventional heavy oil sales production excludes tank inventory volumes.
(5) Liquids means oil, condensate, ethane 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 Acquisition.
(7) Before risk management contracts; supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(8) The Recombination Transaction with Perpetual 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, prior to purchase price adjustments.
(9) The Clearwater acquisition closed on November 8, 2023 for cash consideration of $34.0 million, prior to purchase price adjustments.
(10) Royalty sale closed on December 8, 2023 for cash consideration of $8.0 million, prior to purchase price adjustments.
(11) Based on fourth quarter annualized adjusted funds flow before transaction costs relative to year-end net debt. Non-GAAP financial measure and ratio.

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 December 31, 2024, 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, 2024 and 2023. 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. The date of this MD&A is March 10, 2025.

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 which is engaged in the exploration, development, production and marketing of its diversified asset portfolio which includes conventional heavy crude oil from the Clearwater and Mannville Stack Formations in Eastern Alberta utilizing multi-lateral, horizontal drilling technology, 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".

2024 STRATEGIC 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").

Pursuant to the Recombination Transaction, among other things, a wholly-owned subsidiary of Perpetual and a wholly-owned subsidiary of Rubellite Energy Inc. amalgamated resulting in the creation of Rubellite Energy Corp. with Perpetual and Rubellite Energy Inc. becoming wholly-owned subsidiaries of the Company. On January 1, 2025, Perpetual and Rubellite Energy Inc. amalgamated continuing as Rubellite Energy Inc.

In accordance with the Recombination Transaction, (i) holders of common shares of Rubellite Energy Inc. received one (1) common share of the Company for every one (1) common share of Rubellite Energy Inc. held, (ii) holders of common shares of Perpetual received one (1) common share of the Company for every five (5) Perpetual common 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 share. At closing, shareholders of Rubellite Energy Inc. held 67.6 million shares (72.7%), Perpetual shareholders held 13.7 million shares (14.8%) and holders of Perpetual senior notes held the remaining 12.5% of the Company.

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. As of November 1, 2024, with the closing of the Recombination Transaction, the MSA amounts were nil on a consolidated basis and all technical, capital and administrative services are accounted for by Rubellite Energy Inc.

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 new cash generating unit (the "West Central 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.". For additional information, refer to Note 4 "Acquisitions and Dispositions" in the consolidated financial statements.

Buffalo Mission Acquisition

On August 2, 2024, Rubellite closed the acquisition of Buffalo Mission Energy Corp. ("Buffalo Mission" or "BMEC") (the "BMEC Acquisition"), a private Mannville Stack-focused heavy oil producer in the Frog Lake area. The total consideration paid by Rubellite for BMEC was $96.6 million, inclusive of $23.5 million of BMEC's 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.

The BMEC Acquisition was funded through an expanded credit facility which increased from $60.0 million to $100.0 million, a $20.0 million bank syndicate term loan which was set to mature on December 15, 2024, and a new five year term loan ("Term Loan") placed, directly or indirectly, with certain directors and officers of Rubellite and the Company's significant shareholder for $20.0 million which bears interest at 11.5%. The bank syndicate term loan was repaid in full in conjunction with the closing of the Recombination Transaction on October 31, 2024.

FOURTH QUARTER AND ANNUAL 2024 OPERATIONAL AND FINANCIAL HIGHLIGHTS

- Rubellite delivered record fourth quarter conventional heavy oil sales production of 7,754 bbl/d that exceeded guidance and was 84% above the fourth quarter of 2023 (Q4 2023 - 4,209 bbl/d). Fourth quarter total sales production of 10,386 boe/d (77% heavy oil and NGL) was up 147% from the fourth quarter of 2023. Production growth was driven by the successful drilling program at Figure Lake, the full quarter impact of the BMEC Acquisition and two months of operations at East Edson following the closing of the Recombination Transaction, which added an average of 2,627 boe/d of sales volumes (14.1 MMcf/d of conventional natural gas and 275 bbl/d of NGL). During the fourth quarter, there were seventeen (14.25 net) wells brought on production from the heavy oil drilling program at both Figure Lake and Frog Lake.

- Rubellite delivered 2024 exit rate sales production for the month of December of 12,027 boe/d (8,083 bbl/d heavy oil), exceeding previous production guidance ranges of 11,300 to 11,800 boe/d of total sales (7,500 to 7,900 bbl/d heavy oil).

- Exploration and development capital expenditures(1) totaled $34.4 million for the fourth quarter bringing expenditures to $101.7 million in 2024. Fourth quarter spending included costs to drill, complete, equip and tie-in nine (9.0 net) multi-lateral horizontal development / step-out delineation wells at Figure Lake, five (3.0 net) multi-lateral horizontal development wells at Frog Lake and one (1.0 net) exploratory horizontal four-leg multi-lateral well drilled at Calling Lake / Nixon. Included in fourth quarter development capital spending was $1.8 million for the Figure Lake gas conservation project, bringing total gas plant and pipeline expenditures to $7.2 million in 2024.

- Adjusted funds flow before transaction costs(1) in the fourth quarter was $35.9 million ($0.41 per share) and $100.0 million ($1.46 per share) in 2024 (Q4 2023 - $17.1 million or $0.27 per share; 2023 - $54.3 million or $0.90 per share). Adjusted funds flow after transaction costs(1) for the three and twelve months ended December 31, 2024 were $31.6 and $93.8 million (three and twelve months ended December 31, 2023 - $16.9 and $54.2 million).

- Cash costs(1) were $18.6 million or $19.45/boe in the fourth quarter of 2024 (Q4 2023 - $7.9 million or $20.49/boe) and $50.4 million or $21.68/boe in 2024 (2023 - $25.7 million or $21.29/boe).

- Net income was $26.7 million in the fourth quarter of 2024 (Q4 2023 - $9.5 million net income) and $50.0 million in 2024 (2023 - $18.6 million).

- As at December 31, 2024, net debt(1) was $154.0 million, an increase from $51.0 million as at December 31, 2023 as a result of the BMEC Acquisition during the third quarter of 2024 and capital expenditures of $108.9 million in 2024 which exceeded adjusted funds flow of $93.8 million. At December 31, 2024, net debt to Q4 annualized adjusted funds flow before transaction costs(1) was 1.1 times.

- Rubellite had available liquidity(2) at December 31, 2024 of $30.4 million, comprised of the $140.0 million borrowing limit of Rubellite's first lien credit facility, less current bank borrowings of $108.5 million, outstanding letters of credit of $3.6 million offset by cash and cash equivalents of $2.6 million.

(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".

OPERATIONS UPDATE

In 2024, operational goals were focused on: (1) maximizing the Net Present Value ("NPV") of development locations at Figure Lake through advancements in well design; (2) de-risking the prospective location inventory at Figure Lake through confirmatory step-out drilling; (3) construction and commissioning of the solution gas gathering and natural gas sales infrastructure at Figure Lake; and (4) integration of the Frog Lake assets acquired through the BMEC Acquisition. Positive advancement of these objectives successfully converted the vast majority of Rubellite's ~316 net heavy oil development locations(1) to high confidence locations, solidifying the foundation for Rubellite's longer term organic growth plan.

Operational goals for 2025 include: (1) advancement of enhanced oil recovery opportunities at Figure Lake; (2) ongoing improvement of well designs and development costs across the portfolio; and (3) testing and de-risking of secondary Mannville Stack sands at Frog Lake.

Greater Figure Lake (Figure Lake and Edwand)

Production from the Greater Figure Lake area averaged 5,228 bbl/d (100% heavy oil) in December 2024 and 4,953 bbl/d (100% heavy oil) for the fourth quarter.

In the fourth quarter of 2024, Rubellite operated two rigs to drill and rig release a total of nine (9.0 net) horizontal wells in the Greater Figure Lake area, all targeting the Clearwater formation, bringing the total number of wells drilled in the year to thirty-four (34.0 net) wells. Average results from the 2024 capital program across the Greater Figure Lake field continue to meet or exceed expectations, solidifying confidence in the geologic model and affirming the 243.0 net drilling inventory locations, including 65.6 net proven undeveloped and 30.6 probable undeveloped(1) identified. Under a one-rig program drilling 18 wells per year, the location count at Figure Lake represents over 13 years of economic inventory.

Well Design Pilot

During the second half of 2024, the Company executed a pilot drilling project at the 6-19-62-18W4 Pad (the "6-19 Pad") and 1-25-62-19W4 Pad (the "1-25" Pad) to validate the predicted economic advantage of implementing tighter inter-leg spacing in the Clearwater formation at Figure Lake. Specifically, the Company reduced the distance between laterals from 50m to approximately 33m, and commensurately increased the number of legs from eight to twelve, thereby also increasing the open hole lateral length per well from ~10,000 meters to ~15,000 meters while maintaining the same approximate area coverage per well. Early productivity data from the tighter spacing design is encouraging, both on a per meter and total production per well basis. A total of eight (8.0 net) horizontal wells were drilled with a tighter 33 meter inter-leg spacing which were compared to four (4.0 net) wells drilled with a wider 50 meter inter-leg spacing within the pilot project area. While productivity per meter of open reservoir varies with reservoir quality, the preliminary pilot results suggest that productivity per meter of open reservoir for the wells with tighter inter-leg spacing is statistically similar to the closest neighboring wells, supporting the expectation of economic production acceleration. Incremental drilling time and costs savings per meter drilled for the wells with tighter inter-leg spacing are also encouraging and in line with modeled assumptions, and in combination with early production data suggest that an increase in net asset value per unit area of land will be realized. The 00/08-23-062-19W4 was drilled with a 33 meter inter-leg spacing to a total lateral measured depth of 14,500 meters and achieved an IP30 and IP60 of 304 bbl/d and 266 bbl/d, respectively. The offsetting 02/08-23-062-19W4 was drilled to a total lateral measured depth of 18,600 meters using a hybrid multi-lateral / "fan" design and is on production at similar rates, recording an IP30 and IP60 of 360 bbl/d and 330 bbl/d, respectively.

In view of the positive pilot program results at Figure Lake, the tighter inter-leg spacing drilling design was subsequently implemented at South Edwand at the 7-5-61-17W4 Pad (the "7-5 Pad"), where the 02/06-08-61-17W4 well was drilled to a total lateral measured depth of ~16,960 meters and achieved an IP30 of 378 bbl/d and the 00/07-08-61-17W4 well was drilled to a total lateral measured depth of ~17,125 meters and achieved an IP30 of 264 bbl/d. The Company now intends to develop the remaining Greater Figure Lake area using the 33 meter inter-leg well design to maximize the net present value realized from the field.

Production results from the 2024 drilling program with a 50 meter inter-leg spacing well design averaged IP30 of 156 bbl/d (24 wells) and IP60 of 141 bbl/d (24 wells) to date, as compared to the McDaniel Type Curve(1) for the 8 leg 50 meter well design of 120 bbl/d and 112 bbl/d, respectively. Production results from the pilot program wells with a 33 meter inter-leg spacing averaged IP30 217 bbl/d (9 wells) and IP60 168 bbl/d (6 wells) to date, as compared to the McDaniel Tier 1 Type Curve(1) for the 33 meter spacing well design of IP30 177 bbl/d and IP60 169 bbl/d. Only 2024 drills that have at least 30 or 60 days of production have been included in the averages stated. Other than the producing day criteria, no wells have been excluded in the calculation of the average rate.

Inventory Conversion to Development

Of the thirty four (34.0 net) wells drilled during the year in the Greater Figure Lake area, six (6.0 net) were internally categorized as "step-out delineation" wells and were drilled to confirm new pools or pool extensions. All of the step-out delineation wells were drilled at 50 meter inter-leg spacing with a 100% success rate, with an average IP30 and IP60 of 195 bbl/d and 186 bbl/d, respectively. The success of the step-out drilling program affirms the geologic model and further supports the location inventory identified for future development.

Solution Gas Gathering and Conservation

Subsequent to the end of the fourth quarter, construction, start-up and commissioning of the new Figure Lake gas plant located at 01-13-063-18W4 was completed, and solution gas sales commenced on January 23, 2025. Sales gas production will progressively increase through the first quarter of 2025 to the designed plant capacity of approximately 4 MMcf/d.

The tie-in and sale of solution gas at Figure Lake is forecast to deliver a rate of return in excess of 75%, enhanced by the re-activation of previously decommissioned gas gathering pipelines in the area, and a forecast reduction in carbon taxes related to reduced emissions resulting from the elimination of flaring and incineration at multiple pad sites. With expected ongoing growth in heavy oil volumes, Rubellite is evaluating options to manage additional gas volumes, including expansion of the gas plant for increased sales volumes and temporary gas storage into a depleted reservoir. The Company is also advancing a novel natural gas re-injection pilot at Figure Lake for enhanced oil recovery.

Frog Lake

Production at the Frog Lake property averaged 2,223 bbl/d (100% heavy oil) net to Rubellite in December 2024 and 2,210 bbl/d (100% heavy oil) for the fourth quarter.

Following the closing of the BMEC Acquisition on August 2, 2024, the Company drilled and rig released five (2.5 net) horizontal wells in the third quarter and five (3.0 net) horizontal wells in the fourth quarter.

The wells in 2024 were all drilled with water-based mud. Following drilling with water-based mud, the wells initially produce 100% water, and oil cuts then progressively increase through time as the wells "clean up" and recover the fluid lost to the reservoir during drilling operations. 2024 well results have been in line with expectations, excluding three (1.5 net) wells drilled in a localized structurally low area of the Waseca reservoir having higher than expected water saturations. The peak trailing 30-day average oil production, which management considers indicative of performance for wells drilled with water-based mud, was 119 bbl/d for all wells and 153 bbl/d excluding the subset of three structurally low wells.

Rubellite recently initiated a pilot project at Frog Lake to evaluate the use of oil-based mud ("OBM") as the drilling fluid, consistent with Rubellite's operations at Figure Lake where the use of OBM has demonstrated improved hole cleaning and stability, accelerated clean up, and operational improvements including reduced water handling and disposal costs as compared to conventional water-based mud systems. Definitive results from the pilot project at Frog Lake are expected by the end of the first quarter of 2025; however, drilling costs, initial oil-based mud recovery for re-use, and preliminary well performance has been encouraging, and the Company is continuing to utilize oil-based mud in its ongoing drilling operations.

While the Waseca sand is the primary zone of development at Frog Lake, several wells are being planned to additionally test the less consolidated General Petroleum and Sparky sands in 2025 and 2026, to confirm type curve assumptions and extend known pool limits. Corresponding well design work is currently underway.

Exploration

In the fourth quarter, the Company spud an exploratory four-leg open hole multi-lateral horizontal well approximately 90km north of Figure Lake in the Calling Lake / Nixon area to test a new play concept for which Rubellite currently holds 108 net sections of land. While the Company is encouraged by the quality of the oil recovered to date, significant solids production and low total production rates suggest a lack of consolidation in the reservoir, and possible collapse of the open hole laterals. Planning is underway to run a liner or drill a modified lined fishbone design later in 2025 to further evaluate the economic viability of the play.

Rubellite is continuing to advance additional exploration prospects, pursuing both land capture and play concept de-risking activities, and will report further on those activities in due course.

(1) Of the 316.2 net heavy oil locations described, 93.1 are net proved and 45.6 are net probable included in the 2024 McDaniel Reserve Report.
(2) Type curve assumptions for the 33m spacing well design are based on the Total Proved plus Probable Undeveloped reserves contained in the 2024 McDaniel Reserve Report as disclosed in the Company's 2024 Annual Information Form available under the Company's profile on SEDAR+ at www.sedarplus.ca. "McDaniel" means McDaniel & Associates Consultants Ltd. independent qualified reserves evaluators. "McDaniel Reserve 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, 2024 and a preparation date of March 10, 2025. See "Estimated Drilling Locations. Type curve assumptions for the 50 meter spacing well design are based on the Total Proved plus Probable Undeveloped reserves contained in the 2023 McDaniel Reserve Report as disclosed in the Company's 2023 Annual Information Form.

OUTLOOK AND GUIDANCE

Rubellite plans to operate one rig drilling continuously in the Greater Figure Lake area and a second rig drilling continuously at Frog Lake, throughout 2025. Exploration and development capital spending for the first quarter of 2025 is expected to be approximately $22 to $24 million, including the drilling, completion, equipping and tie-in of: four (4.0 net) multi-lateral horizontal Clearwater development wells at Figure Lake / Edwand; six (4.5 net) multi-lateral horizontal development wells in the Waseca formation at Frog Lake (three upcoming Q1 drills and one upcoming Q2 well will be at 100% working interest as Frog Lake Energy Resources Corp. ("FLERC") has elected gross overriding royalty positions on those wells); one (0.3 net) well at Marten Hills to initiate waterflood; and one (1.0 net) exploration evaluation well. First quarter 2025 capital spending will further include approximately $1.5 million to complete the initial phase of the gas conservation project at Figure Lake and expand the gas gathering system. In West Central Alberta, $0.9 million is forecast to participate with its joint venture partner at East Edson in preparatory surface work for a four (2.0 net) well drilling program in the second half of 2025 to offset natural declines in the Company's liquids-rich natural gas production.

Factoring in recent drilling performance and type curve expectations at Figure Lake/Edwand and at Frog Lake, heavy oil sales volumes are expected to grow approximately 3% to 6% from the fourth quarter of 2024 to average between 8,000 - 8,200 bbl/d in Q1 2025. Total production sales volumes for the first quarter of 2025 are expected to be 12,000 to 12,200 boe/d (70% heavy oil and NGL).

For full year 2025, Rubellite expects to spend a total of $95 to $110 million. Planned capital activity at the low end of the spending guidance range includes: drilling eighteen (18.0 net) multi-lateral development / step-out wells in the Greater Figure Lake area; drilling twenty-four (14.0 net) multi-lateral development / step-out wells in the Frog Lake area; approximately $2.6 million to expand the Figure Lake gas conservation project including additional plant optimization and pipeline tie-ins; drilling one (0.3 net) well at Marten Hills to initiate waterflood; participation in the drilling of four (2.0 net) wells at East Edson; and spending to continue to evaluate additional heavy oil exploration prospects, and to advance enhanced oil recovery ideas in the Clearwater. If market conditions warrant, the Company would look to expand its planned activity levels to the high end of the spending guidance range which would further grow production levels into 2026.

Corresponding heavy oil sales volumes are expected to grow 44% to 48% year-over-year to average between 8,200 - 8,400 bbl/d in 2025. Total production sales volumes, including natural gas and NGL volumes at East Edson and solution gas sales at Figure Lake, are forecast to average 12,200 - 12,400 boe/d in 2025.

Forecast activity will be funded from adjusted funds flow(1), with excess free funds flow applied to reduce net debt(1).

Rubellite has made provisions to potentially add a second drilling rig to the Greater Figure Lake Clearwater drilling program early in the third quarter of 2025, subject to a favorable commodity price outlook in the second quarter of 2025.

Rubellite will continue to address end of life ARO, with total abandonment and reclamation expenditures of approximately $1.9 million planned for 2025. The Company's area-based mandatory spending requirement for 2025 is $1.7 million, as calculated by the Alberta Energy Regulator ("AER").

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

Capital spending and drilling activity for the first quarter and full year 2025 is summarized in the table below:

	Q1 2025(1) ***($ millions)***	**# of wells** ***(gross/net)***	**2025(1)** ***($ millions)***	**# of wells** ***(gross/net)***
Figure Lake		4 / 4.0		18 / 18.0
Frog Lake		6 / 4.5		24 / 14.0
Marten Hills		1 / 0.3		1 / 0.3
East Edson		0 / 0.0		4 / 2.0
Exploration(2)		1 / 1.0		4 / 3.5
Total (1)	**$22 - $24 million**	**12 /9.8**	**$95 - $110 million**	**51 / 37.8**

(1) Excludes abandonment and reclamation spending and acquisitions or land expenditures, if any.
(2) Includes wells at Figure Lake and Frog Lake targeting secondary exploration zones.

Rubellite's guidance for first quarter and full year 2025 is presented in the table below:

	Q1 2025 Guidance	2025 Guidance
Sales Production (boe/d)	12,000 -12,200	12,200 - 12,400
Production mix (% oil and liquids)(1)	70%	70%
Heavy Oil Production (bbl/d)	8,000 - 8,200	8,200 - 8,400
Exploration and Development spending ($ millions)(2)(3)	$22 - $24	$95 - $110
Multi-lateral development / step-out wells (net)(4)	11 (8.8)	47 (34.3)
Exploration wells (net)(5)	1 (1.0)	4 (3.5)
Heavy oil wellhead differential ($/bbl)(2)	$5.00 - $5.50	$5.00 - $5.50
Royalties (% of revenue)(2)	13% - 14%	13% - 14%
Production and operating costs ($/boe)(2)	$7.00 - $7.75	$7.00 - $7.75
Transportation costs ($/boe)(2)	$5.50 - $6.00	$5.50 - $6.00
General and administrative costs ($/boe)(2)	$3.00 - $3.50	$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 land and acquisition spending, if any.
(4) Includes three step-out delineation wells at Figure Lake.
(5) Includes wells at Figure Lake and Frog Lake targeting secondary exploratory zones.

FOURTH QUARTER 2024 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 and land expenditures, if any. "Capital Expenditures" is not a standardized measure and, 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,					
	2024			2023		
($ thousands)	**E&E**	**PP&E**	**Total**	E&E	PP&E	Total
Drilling and completions	**1,909**	**25,264**	**27,173**	10,095	10,324	20,419
Facilities	**255**	**5,431**	**5,686**	(518)	1,765	1,247
Lease construction	**119**	**1,420**	**1,539**	2,322	1,143	3,465
Capital Expenditures(1)	**2,283**	**32,115**	**34,398**	11,899	13,232	25,131
Land and other	**561**	**450**	**1,011**	1,189	—	1,189
Corporate	**—**	**128**	**128**	—	—	—
Capital expenditures, including land and other(1)	**2,844**	**32,693**	**35,537**	13,088	13,232	26,320
Acquisitions(2)(3)	**2,692**	**65,775**	**68,467**	4,526	28,647	33,173
Proceeds from dispositions(4)	**—**	**—**	**—**	(1,073)	(6,917)	(7,990)
Capital expenditures(1), after acquisitions	**5,536**	**98,468**	**104,004**	16,541	34,962	51,503

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Recombination Transaction with Perpetual closed on October 31, 2024 for share consideration of $51.7 million.
(3) Clearwater Asset Acquisition closed on November 8, 2023 for cash consideration of $34.0 million, prior to purchase price adjustments.
(4) Royalty sale closed on December 8, 2023 for cash consideration of $8.0 million, prior to purchase price adjustments.

	Twelve months ended December 31,					
	2024			2023		
($ thousands)	**E&E(2)**	**PP&E**	**Total**	E&E	PP&E	Total
Drilling and completions	**9,373**	**69,111**	**78,484**	18,543	32,533	51,076
Facilities	**747**	**15,789**	**16,536**	2,820	6,482	9,302
Lease construction	**1,458**	**5,254**	**6,712**	2,491	4,645	7,136
Capital Expenditures(1)	**11,578**	**90,154**	**101,732**	23,854	43,660	67,514
Land and other	**3,551**	**526**	**4,077**	4,016	—	4,016
Corporate(3)	**—**	**3,097**	**3,097**	—	—	—
Capital expenditures, including land and other	**15,129**	**93,777**	**108,906**	27,870	43,660	71,530
Acquisitions(4)(5)(6)	**2,692**	**176,555**	**179,247**	4,526	28,647	33,173
Proceeds from dispositions(7)	**—**	**—**	**—**	(1,073)	(6,917)	(7,990)
Capital expenditures, after acquisitions	**17,821**	**270,332**	**288,153**	31,323	65,390	96,713

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Included within E&E are $8.3 million of expenditures related to four (4.0 net) wells in Figure Lake that were transferred to PP&E during 2024.
(3) 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 include costs billed under the MSA for shared office leasehold improvements.
(4) Recombination Transaction with Perpetual closed on October 31, 2024 for share consideration of $51.7 million.
(5) BMEC Acquisition closed on August 2, 2024 for total consideration of $73.1 million, prior to purchase price adjustments.
(6) Clearwater Asset Acquisition closed on November 8, 2023 for cash consideration of $34.0 million, prior to purchase price adjustments.
(7) Royalty sale closed on December 8, 2023 for cash consideration of $8.0 million, prior to purchase price adjustments.

Capital expenditures by CGU

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands)	**2024**	2023	**2024**	2023
Capital expenditures				
Eastern Heavy Oil	**34,710**	26,320	**105,110**	71,530
West Central(1)	**699**	—	**699**	—
Capital expenditures(2), including land and other	**35,409**	26,320	**105,809**	71,530

(1) As a result of the Recombination Transaction with Perpetual, the West Central CGU represents Perpetual's legacy conventional natural gas assets, a majority of which are operated by a 50% joint venture partner.
(2) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".

Wells drilled by area

(gross/net)	Three months ended December 31, **2024**	2023	Twelve months ended December 31, **2024**	2023
Development				
Figure Lake(1)	**9 / 9.0**	11 / 11.0	**34 / 34.0**	27 / 27.0
Frog Lake(2)(3)	**5 / 3.0**	- / -	**10 / 5.5**	- / -
Northern Exploration				
Dawson	**- / -**	- / -	**- / -**	1 / 0.5
Peavine	**- / -**	- / -	**- / -**	2 / 2.0
Other exploratory(4)(5)	**1 / 1.0**	- / -	**2.0 / 2.0**	- / -
Total	**15 / 13.0**	11 / 11.0	**46 / 41.5**	30 / 29.5

(1) One (1.0 net) well drilled at the 7-05 pad at Figure Lake was spud on December 20, 2024 and rig released January 19, 2025 and not included in the Q4 2024 well count.
(2) One (0.5 net) well drilled at the 1-01 pad at Frog Lake was spud on December 20, 2024 and rig released January 15, 2025 and not included in the Q4 2024 well count.
(3) One well drilled at the 3-29 pad at Frog Lake was drilled at 100% working interest cost to earn a 75% working interest before payout and 50% working interest after payout.
(4) One (1.0 net) vertical stratigraphic evaluation well was drilled in Q1 2024 and remains in E&E as at December 31, 2024.
(5) One (1.0 net) horizontal four-leg multi-lateral evaluation well at Calling Lake/Nixon was drilled in Q4 2024 and remains in E&E as at December 31, 2024.

Capital Expenditures

During the fourth quarter of 2024, Rubellite invested a total of $34.4 million, before land and other corporate spending, related primarily to the drilling, completion, equipping and tie-in of nine (9.0 net) multi-lateral horizontal wells at Figure Lake and five (3.0 net) multi-lateral horizontal wells at Frog Lake. A portion of capital to drill one (1.0 net) additional well at Figure Lake and one (0.5 net) well at Frog Lake was spent during the fourth quarter and the wells finished drilling and were rig released at the beginning of the first quarter. In addition, there was one exploratory horizontal four-leg, multi-lateral horizontal well drilled in the fourth quarter. Facilities spending at Figure Lake in the fourth quarter included $1.8 million of expenditures related to the construction of a sales gas plant as part of the Figure Lake gas conservation project. Following the closing of the Recombination Transaction between Perpetual and Rubellite, at the Company's West Central conventional natural gas asset at Edson, Rubellite spent $0.6 million for lease construction, facility improvements and pipelines to support the 2025 drilling program with its 50% joint venture partner.

During 2024, the Company spent $101.7 million, before land and other corporate spending, primarily related to the drilling, completion, equipping and tie-in of thirty four (34.0 net) multi-lateral horizontal wells at Figure Lake, ten (5.5 net) multi-lateral horizontal wells at Frog Lake, drilling and coring of one (1.0 net) vertical stratigraphic evaluation well and drilling of one (1.0 net) horizontal four-leg multi-lateral horizontal evaluation well. Facilities spending at Figure Lake included $7.2 million related to the Figure Lake gas conservation project.

Land and seismic purchases were $1.0 million in the fourth quarter of 2024 to acquire 24.0 net sections of land, with total land purchases in 2024 of $4.1 million to acquire 41.5 net sections of land. Corporate spending for 2024 was $3.1 million and related to leasehold improvements for the shared office space under the MSA prior to the Recombination Transaction.

During the fourth quarter of 2024, Rubellite spent $0.2 million (Q4 2023 - nil) on abandonment and reclamation projects. For the year ended December 31, 2024 , Rubellite spent $0.5 million (2023 - nil) and one reclamation certificate was received from the AER (2023 - nil).

Production

	Three months ended December 31, **2024**	2023	Twelve months ended December 31, **2024**	2023
Sales volumes				
Heavy oil (bbl/d)	**7,754**	4,209	**5,685**	3,302
Natural gas (Mcf/d)(1)	**14,140**	—	**3,570**	—
NGL (bbl/d)(2)	**275**	—	**69**	—
Total sales volumes (boe/d)	**10,386**	4,209	**6,349**	3,302

(1) Conventional natural gas production yielded a heat content of 1.18 GJ/Mcf for the three months ended December 31, 2024, 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, 2024 by CGU:

	Three months ended December 31, **2024**	2023	Twelve months ended December 31, **2024**	2023
Sales volumes by CGU				
Eastern Heavy Oil (boe/d)	**7,759**	4,209	**5,689**	3,302
West Central (boe/d)	**2,627**	—	**660**	—
Total sales volumes (boe/d)	**10,386**	4,209	**6,349**	3,302

Sales production for the three and twelve months ended December 31, 2024 increased by 6,177 boe/d (147%) and 3,047 boe/d (92%) from the comparative periods of 2023. Production growth was driven by the successful drilling program at Figure Lake, the full quarter impact of the BMEC Acquisition and two months of operations at East Edson following the closing of the Recombination Transaction.

During 2024, production and sales volumes progressively increased as new wells were drilled and commenced delivery to sales terminals. During the fourth quarter, an additional seventeen (14.25 net) wells from the Eastern Heavy Oil drilling program were contributing to sales production, with an additional two (2.0 net) wells recovering OBM drilling fluid in Figure Lake, and an additional three (3.0 net) wells recovering drilling fluid in Frog Lake and not yet contributing to sales as at the end of the fourth quarter. With two months of operations following closing of the Recombination Transaction, the Perpetual assets added 2,627 boe/d and 660 boe/d of natural gas and NGL sales production to the three and twelve months ended December 31, 2024. The BMEC Acquisition at Frog Lake which closed in the third quarter of 2024 contributed 2,210 boe/d and 940 boe/d of sales production to the three and twelve months ended December 31, 2024.

As a result of the Recombination Transaction, the fourth quarter sales product mix was comprised of 77% conventional heavy crude oil and NGL and 23% conventional natural gas, as compared to 100% conventional heavy crude oil in the fourth quarter of 2023. For 2024, the product mix was 91% conventional heavy crude oil and NGL and 9% conventional natural gas (2023 - 100% conventional heavy crude oil).

Oil Revenue

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands, except as noted)	**2024**	2023	**2024**	2023
Oil and natural gas revenue				
Oil	**54,912**	27,224	**164,206**	88,968
Natural gas	**2,618**	—	**2,627**	—
NGL	**1,551**	—	**1,551**	—
Oil and natural gas revenue	**59,081**	27,224	**168,384**	88,968
Reference prices				
West Texas Intermediate ("WTI") (US$/bbl)	**70.27**	78.32	**75.72**	77.62
Foreign Exchange rate (CAD$/US$)	**1.40**	1.36	**1.37**	1.35
West Texas Intermediate ("WTI") (CAD$/bbl)	**98.38**	106.52	**103.74**	104.79
Western Canadian Select ("WCS") differential (US$/bbl)	**(12.56)**	(21.98)	**(14.76)**	(18.73)
WCS (CAD$/bbl)	**80.74**	76.84	**83.52**	79.46
AECO 5A Daily Index (CAD$/GJ)	**1.40**	2.18	**1.38**	2.50
AECO 5A Daily Index (CAD$/Mcf)(1)	**1.48**	2.30	**1.46**	2.64
Rubellite average realized prices(2)				
Oil ($/bbl)	**76.97**	70.31	**78.92**	73.82
Natural gas ($/Mcf)	**2.01**	—	**2.01**	—
NGL ($/bbl)	**61.32**	—	**61.32**	—
Average realized price ($/boe)	**61.83**	70.31	**72.46**	73.82

(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 for the three and twelve months ended December 31, 2024 increased by $31.9 million (117%) and $79.4 million (89%) from the comparative periods of 2023, primarily driven by the increase in sales volumes.

Oil revenue for the fourth quarter of 2024 of $54.9 million represented 93% of total revenue while conventional heavy crude oil production was 77% of total sales volumes. Driven by the 147% increase in heavy crude oil production, oil revenue increased 102% from the fourth quarter of 2023. Compared to the fourth quarter of 2023, the WCS average price increased to $80.74/bbl (Q4 2023 - $76.84/bbl), attributable to the WCS differential narrowing by 43% and the increase in the CAD$/US$ rate to $1.40 (Q4 2023 - $1.36), partially offset by a 10% decrease in WTI prices.

For the twelve months ended December 31, 2024, oil revenue increased 85% compared to prior year, as a result of the 92% increase in sales volumes and a 7% increase in realized oil prices. During 2024, the increase in the WCS average price was driven by the narrowing of the WCS differential to US$14.76/bbl (2023 - $18.73/bbl) an increase in the CAD$/US$ rate to $1.37 (2023 - $1.35), partially offset by a 2% decrease in WTI oil prices to US$75.72/bbl (2023 - US$77.62/bbl).

Rubellite's realized oil price reflects a price offset for quality and optimization of sales delivery points which averaged $3.28/bbl and $3.76/bbl for the three and twelve months ended December 31, 2024, as compared to $6.53/bbl and $5.64/bbl in the comparative periods of 2023.

As a result of the Recombination Transaction, Perpetual's conventional natural gas assets generated natural gas revenue of $2.6 million and NGL revenue of $1.6 million in the three and twelve months ended December 31, 2024. With the change in the product mix of the Company, total realized prices on a boe basis decreased 12% and 2% from the comparative 2023 periods, partially offsetting higher sales volumes and realized oil prices.

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 cash flows from potential volatility and lock in economics on drilling programs.

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)	**2024**	2023	**2024**	2023
Unrealized gain (loss) on risk management contracts				
Unrealized gain (loss) on oil contracts	**(9,840)**	12,008	**(8,744)**	8,652
Unrealized loss on natural gas contracts(2)	**(3,508)**	—	**(3,508)**	—
Unrealized gain (loss) on risk management contracts	**(13,348)**	12,008	**(12,252)**	8,652
Realized gain (loss) on risk management contracts				
Realized gain (loss) on oil contracts	**822**	700	**244**	(318)
Realized gain on natural gas contracts	**2,338**	—	**2,338**	—
Realized gain (loss) on risk management contracts	**3,160**	700	**2,582**	(318)
Realized gain (loss) on risk management contracts *($/boe)*	**3.31**	1.81	**1.11**	(0.26)

(1) Supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(2) Financial natural gas contracts included in the Recombination Transaction with Perpetual were initially fair valued at $10.1 million at closing at October 31, 2024 and revalued to $6.6 million at December 31, 2024.

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,	
	2024	2023	**2024**	2023
Realized gain (loss) on risk management contracts				
Realized gain (loss) on oil contracts ($/bbl)	**1.15**	1.81	**0.12**	(0.26)
Realized gain on natural gas contracts ($/Mcf)	**1.80**	—	**1.79**	—
Realized gain (loss) on risk management contracts ($/boe)	**3.31**	1.81	**1.11**	(0.26)
Average realized prices after risk management contracts(1)				
Oil ($/bbl)	**78.12**	72.12	**79.04**	73.56
Natural gas ($/Mcf)	**3.81**	—	**3.80**	—
NGL ($/bbl)	**61.32**	—	**61.32**	—
Average realized price ($/boe)(1)	**65.14**	72.12	**73.57**	73.56

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

The realized gain on risk management contracts totaled $3.2 million or $3.31/boe for the fourth quarter of 2024, compared to a gain of $0.7 million, or $1.81/boe, for the fourth quarter of 2023. For the twelve month period ending December 31, 2024, the realized gain on risk management contracts totaled $2.6 million, or $1.11/boe (2023 - realized loss of $0.3 million or $0.26/boe). Hedging gains or losses are attributable to reference price 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 at any given time.

The unrealized loss on risk management contracts was $13.3 million for the fourth quarter of 2024 (Q4 2023 – $12.0 million unrealized gain) and the unrealized loss on risk management contracts was $12.3 million for the twelve month period ended December 31, 2024 (2023 - $8.7 million unrealized gain). 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)	**2024**	2023	**2024**	2023
Total royalty expenses	**7,743**	2,865	**20,272**	8,513
Total ($/boe)	**8.10**	7.40	**8.72**	7.06
Total *(% of oil revenue)(1)*	**13.1**	10.5	**12.0**	9.6

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

Total royalties for the three and twelve months ended December 31, 2024 were $7.7 million and $20.3 million, an increase from the comparative periods of 2023 on higher production, increased revenue and higher royalty rates. On a per boe basis, royalties increased due to an increase in the relative split of production on lands with higher gross overriding royalties ("GORR") and an increase in the crown royalty rate. Additionally, the production associated with the Frog Lake assets from the BMEC Acquisition and the West Central conventional natural gas assets from the Recombination Transaction have a higher royalty rate in comparison to the Company's Clearwater assets. Consistent with higher per boe royalty rates, royalties as a percentage of revenue were higher for the same reasons.

Rubellite's royalties consist of Crown royalties payable to the Alberta provincial government, royalties payable to Indian Oil and Gas Canada ("IOGC"), and other freehold and GORR. The mix between Crown, IOGC and freehold 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”), the Company pays a Crown royalty of between 5% and 20% on wells where mineral rights are leased from the Crown. Under the Indian Oil and Gas Act, the Company pays a royalty of between 10% and 37% on wells where mineral rights are leased. The remainder of royalties are attributable to the composition of freehold and GORR royalties, some of which are price sensitive.

Net operating costs [1]

($ thousands, except as noted)	Three months ended December 31, 2024	2023	Twelve months ended December 31, 2024	2023
Net operating costs	**6,536**	2,191	**16,514**	7,371
$/boe	**6.84**	5.66	**7.11**	6.12

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

Total net operating costs for the three and twelve months ended December 31, 2024 increased to $6.5 million and $16.5 million from $2.2 million and $7.4 million in the comparative periods of 2023, as a result of the increase in production volumes and higher costs in all areas which included increased carbon tax. For the twelve months ended December 31, 2024, Rubellite has estimated carbon taxes relating to 2024 of $2.0 million, which are payable in June 2025.

On a per boe basis, net operating costs increased by 21% to $6.84/boe in the fourth quarter of 2024 (Q4 2023 - $5.66/boe) and increased 16% to $7.11/boe for the twelve months ended December 31, 2024 (2023 - $6.12/boe). The increase reflects a higher per unit operating cost on the Frog Lake properties from the BMEC Acquisition in the third quarter of 2024 as compared to the Company's Clearwater assets. Lower operating costs per boe in the West Central CGU at East Edson of $4.32/boe in the quarter partially offset the impact of higher operating costs at Frog Lake as Perpetual's West Central conventional natural gas assets carry a lower operating per unit cost than Rubellite's heavy oil properties. For the twelve months ended December 31, 2024, the impact of carbon tax was $0.88/boe as compared to $0.50/boe in 2023.

Transportation costs

($ thousands, except as noted)	Three months ended December 31, 2024	2023	Twelve months ended December 31, 2024	2023
Transportation costs	**5,747**	2,588	**16,328**	9,045
$/boe	**6.01**	6.68	**7.03**	7.50

In the fourth quarter, after the recombination of Rubellite and Perpetual, transportation costs includes clean oil trucking costs and NGL transportation, as well as costs to transport natural gas from the plant gate to commercial sales point. Costs for the three and twelve months ended December 31, 2024 increased to $5.7 million and $16.3 million, up from $2.6 million and $9.0 million in the comparative period of 2023 as a result of higher volumes.

On a per boe basis, transportation costs of $6.01/boe were 10% lower than the fourth quarter of 2023 (Q4 2023 - $6.68/boe) and 6% lower for the twelve months ended December 31, 2024 (2023 - $7.50/boe) due to lower trucking rates realized for the Company's Clearwater assets in 2024 and the addition of natural gas volumes which incur lower transportation costs than the heavy oil assets.

Operating netbacks

The following tables highlight Rubellite's operating netbacks for the three months ended December 31, 2024 and 2023**:**

	Three months ended December 31, 2024			Three months ended December 31, 2023		
($ thousands)	**Eastern Heavy Oil**	**West Central**	**Total**	Eastern Heavy Oil	West Central	Total
Revenue	**54,915**	**4,166**	**59,081**	27,224	—	27,224
Royalties	**(6,950)**	**(793)**	**(7,743)**	(2,865)	—	(2,865)
Net operating costs[1]	**(5,492)**	**(1,044)**	**(6,536)**	(2,191)	—	(2,191)
Transportation costs	**(5,326)**	**(421)**	**(5,747)**	(2,588)	—	(2,588)
Operating netback[1]	**37,147**	**1,908**	**39,055**	19,580	—	19,580
Realized gain on risk management contracts	**822**	**2,338**	**3,160**	700	—	700
Total operating netback, after risk management contracts[1]	**37,969**	**4,246**	**42,215**	20,280	—	20,280

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

	Three months ended December 31, 2024			Three months ended December 31, 2023		
($ boe)	**Eastern Heavy Oil**	**West Central**	**Total**	Eastern Heavy Oil	West Central	Total
Revenue	**76.93**	**17.23**	**61.83**	70.31	—	70.31
Royalties	**(9.74)**	**(3.28)**	**(8.10)**	(7.40)	—	(7.40)
Net operating costs[1]	**(7.69)**	**(4.32)**	**(6.84)**	(5.66)	—	(5.66)
Transportation costs	**(7.46)**	**(1.74)**	**(6.01)**	(6.68)	—	(6.68)
Operating netback[1]	**52.04**	**7.89**	**40.88**	50.57	—	50.57
Realized gain on risk management contracts	**1.15**	**1.80**	**3.31**	1.81	—	1.81
Total operating netback, after risk management contracts[1]	**53.19**	**9.69**	**44.19**	52.38	—	52.38

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

The following tables highlight Rubellite's operating netbacks for the twelve months ended December 31, 2024 and 2023**:**

	Twelve months ended December 31, 2024			Twelve months ended December 31, 2023		
($ thousands)	**Eastern Heavy Oil**	**West Central**	**Total**	Eastern Heavy Oil	West Central	Total
Revenue	**164,218**	**4,166**	**168,384**	88,968	—	88,968
Royalties	**(19,479)**	**(793)**	**(20,272)**	(8,513)	—	(8,513)
Net operating costs(1)	**(15,470)**	**(1,044)**	**(16,514)**	(7,371)	—	(7,371)
Transportation costs	**(15,907)**	**(421)**	**(16,328)**	(9,045)	—	(9,045)
Operating netback(1)	**113,362**	**1,908**	**115,270**	64,039	—	64,039
Realized gain (loss) on risk management contracts	**244**	**2,338**	**2,582**	(318)	—	(318)
Total operating netback, after risk management contracts(1)	**113,606**	**4,246**	**117,852**	63,721	—	63,721

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

	Twelve months ended December 31, 2024			Twelve months ended December 31, 2023		
($/boe)	**Eastern Heavy Oil**	**West Central**	**Total**	Eastern Heavy Oil	West Central	Total
Revenue	**78.87**	**17.23**	**72.46**	73.82	—	73.82
Royalties	**(9.36)**	**(3.28)**	**(8.72)**	(7.06)	—	(7.06)
Net operating costs(1)	**(7.43)**	**(4.32)**	**(7.11)**	(6.12)	—	(6.12)
Transportation costs	**(7.64)**	**(1.74)**	**(7.03)**	(7.50)	—	(7.50)
Operating netback(1)	**54.44**	**7.89**	**49.60**	53.14	—	53.14
Realized gain (loss) on risk management contracts	**0.12**	**1.79**	**1.11**	(0.26)	—	(0.26)
Total operating netback, after risk management contracts(1)	**54.56**	**9.68**	**50.71**	52.88	—	52.88

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

Rubellite's Eastern Heavy Oil operating netback for the three and twelve months ended December 31, 2024 increased to $37.1 million ($52.04/boe) and $113.4 million ($54.44/boe) (Q4 2023 - $19.6 million or $50.57/boe; 2023 - $64.0 million or $53.14/boe). The increase was the result of higher sales volumes and realized oil prices which increased revenue, partially offset by higher royalties and costs reflecting higher production. On a per boe basis, higher royalties, net operating costs and transportation costs were attributable to the addition of the Frog Lake property in the third quarter of 2024, which carried a higher cost base and royalty structure than the Company's Clearwater properties.

Rubellite's total operating netback for the three and twelve months ended December 31, 2024 increased to $39.1 million and $115.3 million from $19.6 million and $64.0 million in the comparative periods of 2023. On a per boe basis, the decrease in the operating netback for the three and twelve months ended December 31, 2024 was driven by lower realized prices as a result of the changes to the sales product mix, higher royalties and net operating costs, partially offset by lower transportation costs.

The operating netback after risk management costs for the three and twelve months ended December 31, 2024 was $44.19/boe and $50.71/boe (Q4 2023 – $52.38/boe; 2023 - $52.88/boe).

General and administrative ("G&A") expenses

	Three months ended December 31,		Twelve months ended December 31,	
($ thousands, except as noted)	**2024**	2023	**2024**	2023
G&A expenses – before MSA costs & recoveries	**4,698**	1,510	**7,292**	3,964
G&A recoveries	**(1,687)**	—	**(1,687)**	—
MSA costs	**511**	813	**5,011**	3,354
Total G&A expenses	**3,522**	2,323	**10,616**	7,318
$/boe	**3.69**	6.00	**4.57**	6.07

Prior to the Recombination Transaction, Rubellite had the 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. Effective June 1, 2024, the MSA was amended to split shared costs on a 80% Rubellite and 20% Perpetual basis. As of November 1, 2024, with the closing of the Recombination Transaction, the MSA amounts were nil on a consolidated basis. MSA costs in the fourth quarter of 2024 were lower due to the removal of the MSA on a consolidated basis. For the twelve months ended December 31, 2024, MSA costs increased as a result of Rubellite's increased production relative to Perpetual's production and the amendment of the MSA in June 2024, which changed to a cost sharing basis to 80% Rubellite and 20% Perpetual.

G&A expenses, excluding MSA costs, for the three and twelve months ended December 31, 2024 increased to $4.7 million and $7.3 million (Q4 2023 – $1.5 million; 2023 - $4.0 million). Prior to the Recombination Transaction, G&A expenses, excluding MSA costs, consisted primarily of legal fees, computer software licenses, insurance, audit fees and tax related consulting fees and were higher in 2024 as a result of higher costs driven by Rubellite's growth. After the Recombination Transaction was completed on November 1, 2024, G&A expenses in Rubellite included all G&A costs, including people, office and computer costs and recoveries that were previously billed through the MSA.

For the three and twelve months ended December 31, 2024, G&A costs on a per boe basis decreased to $3.69/boe and $4.57/boe from $6.00/boe and $6.07/boe in the comparative periods of 2023 due to higher sales volumes and cost efficiencies realized as a result of the Recombination Transaction.

Depletion

($ thousands, except as noted)	Three months ended December 31, 2024		2023		Twelve months ended December 31, 2024		2023	
Depletion	**19.51**	**18,645**	21.17	8,195	**21.17**	**49,192**	22.80	27,485
Depreciation	**0.46**	**443**	—	—	**0.28**	**655**	—	—
Total depletion and depreciation	**19.97**	**19,088**	21.17	8,195	**21.45**	**49,847**	22.80	27,485

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, 2024, depletion was calculated on a $473.4 million depletable balance (December 31, 2023 – $208.0 million), $436.3 million in future development costs (December 31, 2023 – $145.1 million) and excluded an estimated $8.7 million of salvage value (December 31, 2023 – $3.4 million) and $7.2 million (December 31, 2023 - nil) of assets under construction.

Depletion and depreciation expense for the fourth quarter of 2024 was $19.1 million or $19.97/boe (Q4 2023 – $8.2 million or $21.17/boe). For the twelve month period ended December 31, 2024 depletion and depreciation expense was $49.8 million or $21.45/boe (2023 - $27.5 million or $22.80/boe). The increase in depletion related to a higher depletable base than the comparable periods as a result of the BMEC Acquisition and the Recombination Transaction. On a per boe basis, depletion decreased for the three and twelve month period compared to the respective prior year periods as a result of the Recombination Transaction as the Perpetual assets have higher reserves relative to production than Rubellite's heavy oil assets. Depletion will fluctuate from one period to the next depending on the amount of capital spent, the amount of reserves added and volumes produced.

Impairment

There were no indicators of impairment for either of the Company's CGUs as at December 31, 2024, therefore, an impairment test was not performed.

E&E assets are tested for impairment when internal or external indicators of impairment exist as well as upon reclassification to oil and natural gas interests in PP&E. At December 31, 2024, the Company conducted an assessment of indicators of impairment for the Company's E&E assets. In performing the assessment, management determined there were no indicators of impairment.

During the three and twelve months ended December 31, 2024, the Company transferred nil and $20.8 million, respectively, of E&E to PP&E 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 transferred $22.6 million of E&E to PP&E during 2023 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.

Finance expense

($ thousands)	Three months ended December 31, 2024	2023	Twelve months ended December 31, 2024	2023
Cash finance expense				
Interest on bank debt	**2,149**	831	**5,897**	1,923
Interest on Term Loan	**580**	—	**952**	—
Interest on lease liabilities	**55**	—	**55**	—
Total cash finance expense	**2,784**	831	**6,904**	1,923
Non-cash finance expense				
Amortization of debt issue costs	**62**	—	**63**	—
Accretion on decommissioning obligations	**108**	36	**316**	128
Accretion on other provision	**69**	—	**93**	—
Total non-cash finance expense	**239**	36	**472**	128
Finance expense	**3,023**	867	**7,376**	2,051

Total cash finance expense for the three and twelve months ended December 31, 2024 increased to $2.8 million and $6.9 million from $0.8 million and $1.9 million in the comparative periods of 2023 as a result of higher outstanding bank debt and the addition of the Term Loan to fund the BMEC Acquisition. The effective aggregate interest rate on the Company's revolving bank line and bank syndicate term loan for the three and twelve months ended December 31, 2024 was 6.7% and 8.2% (three and twelve months ended December 31, 2023 - 10.1% and 8.5%). The effective interest rate on the Company's Term Loan for the three and twelve months ended December 31, 2024 was 12.9%.

Non-cash finance expense represents accretion on decommissioning obligations, accretion on other provision and amortization of debt issue costs.

Deferred Income Taxes

	Three months ended December 31,		Twelve months ended December 31,	
	2024	2023	**2024**	2023
Income before income tax	**$ 29,008**	$ 20,848	**$ 59,033**	$ 26,603
Combined federal and provincial tax rate	**23%**	23%	**23%**	23%
Computed income tax expense	**6,672**	4,795	**13,578**	6,119
Increase (decrease) in income taxes resulting from:				
Non-deductible expenses	**315**	252	**763**	700
Non-taxable gain on acquisition	**(7,272)**	—	**(7,272)**	—
Flow-through shares - tax pools renounced	**—**	213	**—**	3,048
Other	**(331)**	303	**(551)**	(377)
Change in unrecognized deferred tax assets	**2,876**	5,762	**2,542**	(1,448)
Deferred tax expense	**2,260**	11,325	**9,060**	8,042

For the three and twelve months ended December 31, 2024, the Company recorded a deferred income tax expense of $2.3 million and $9.1 million, compared to an income tax expense of $11.3 million and $8.0 million in the comparative periods of 2023. For the fourth quarter of 2024 the Company recorded higher net income before taxes which was offset by a non-taxable gain on acquisition and a decrease in the unrecognized deferred tax assets, as compared to the comparative period which had lower net income before taxes offset by a larger increase in unrecognized deferred tax assets. For the twelve month period ended December 31, 2024, Rubellite incurred higher net income before taxes which were offset by a non-taxable gain on acquisition and an increase in the unrecognized deferred tax assets, as compared to the prior year, which had lower income before taxes offset by the renouncing of tax pools related to a flow-share share offering.

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, the Company 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, 2024**	December 31, 2023
Revolving bank debt(1)	**105,945**	29,317
Term Loan (principal)	**20,000**	—
Adjusted working capital deficit(2)(4)	**28,075**	21,667
Net debt(1)	**154,020**	50,984
Shares outstanding at end of period (*thousands*)	**93,044**	62,456
Market price at end of period (*$/share*)	**2.12**	2.01
Market value of shares(2)	**197,253**	125,537
Enterprise value(1)	**351,273**	176,521
Net debt as a percentage of enterprise value(2)	**44%**	29%
Trailing twelve-months adjusted funds flow(2)	**93,777**	54,157
Net debt to adjusted funds flow ratio(2)	**1.6**	0.9
Q4 annualized adjusted funds flow(2)(3)	**143,420**	68,280
Net debt to Q4 annualized adjusted funds flow ratio(2)(3)	**1.1**	0.7

(1) Revolving bank debt shown net of cash balance of $2.6 million as at December 31, 2024 (December 31, 2023 - nil).
(2) Non-GAAP measure or ratio. See "Non-GAAP and Other Financial Measures".
(3) Based on Q4 2024 adjusted funds flow before transaction costs of $35.9 million, net debt to Q4 annualized adjusted funds flow ratio is 1.1 times at December 31, 2024. See "Non-GAAP and Other Financial Measures" for more details.
(4) Adjusted working capital deficit excludes cash balance of $2.6 million as at December 31, 2024 (December 31, 2023 - nil).

At December 31, 2024, Rubellite had net debt of $154.0 million, a 202% increase from $51.0 million at December 31, 2023. Net debt increased as a result of the BMEC Acquisition in the third quarter which was funded largely from an expanded credit facility and the Term Loan. In addition, capital expenditures, including land and other, of $108.9 million in 2024 exceeded adjusted funds flow of $93.8 million. The Recombination Transaction did not have a material impact on net debt as consideration was in the form of the issuance of shares with minimal bank debt and working capital assumed.

Rubellite had available liquidity at December 31, 2024 of $30.4 million, comprised of the $140.0 million Credit Facility Borrowing Limit, less bank borrowings of $108.5 million, outstanding letters of credit of $3.6 million and cash and cash equivalents of $2.6 million.

Bank debt

As at December 31, 2024, the Company's first lien credit facility, upon closing of the Recombination Transaction, had a borrowing limit of $140.0 million (December 31, 2023 - $57.0 million). The initial term is to May 31, 2025 and may be extended for a further twelve months to May 31, 2026 subject to lender approval. If not extended by May 31, 2025, all outstanding advances would be repayable on May 31, 2026. The next semi-annual borrowing base redetermination is scheduled on or before May 31, 2025.

On August 2, 2024, the Company's lenders provided a $20.0 million (December 31, 2023 - nil) bank syndicate term loan which bore interest at the lenders prime rate or Canadian Overnight Repo Rate Average ("CORRA") rates, plus applicable margins and standby fees. The bank syndicate term loan was repaid in full in conjunction with the closing of the Recombination Transaction on October 31, 2024.

As at December 31, 2024, $108.5 million was drawn against the credit facility (December 31, 2023 - $29.3 million). Letters of credit outstanding at period end were $3.6 million (December 31, 2023 - $0.4 million). 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 during the fourth quarter of 2024 was 6.7% per annum. For the period ended December 31, 2024, if interest rates changed by 1% with all other variables held constant, the impact on annual cash finance expense and net income and comprehensive income would be $0.8 million.

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

At December 31, 2024, 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, 2024		December 31, 2023	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term loan	August 2, 2029	11.5%	**20,000**	**19,027**	—	—

On August 2, 2024, Rubellite entered into a senior secured second-lien term loan ("Term Loan") which was placed, directly or indirectly, with certain directors and officers of Rubellite and the Company's significant shareholder for $20.0 million. The Term Loan bears interest at 11.5% annually with interest payments to be paid quarterly and 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.

During the three and twelve months ending December 31, 2024, Rubellite paid $0.6 million and $1.0 million in cash interest payments to the holders of the Term Loan (three and twelve months ended December 31, 2023 - nil).

At December 31, 2024, the Term Loan has been recorded at the present value of future cash flows, net of $1.0 million in issue and discount costs which are amortized over the remaining term using a weighted average effective interest rate of 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, 2024, entities controlled or directed by the Company's Chief Executive Officer ("CEO") hold $18.4 million of the outstanding Term Loan.

Equity

At December 31, 2024, there were 92.9 million common shares outstanding, net of 0.2 million shares held in trust for employee compensation programs. At December 31, 2023, there were 62.5 million common shares and 4.0 million Share Purchase Warrants outstanding. The Share Purchase Warrants have an exercise price of $3.00 per share and expire on October 5, 2026. As a result of the completion of the Recombination Transaction, the Share Purchase Warrants are no longer outstanding.

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 consisted of 11.6 million common shares to the holders of Perpetual senior notes and 13.7 million common shares to holders of Perpetual common shares based on a conversion price of $2.25 per share. The common shares issued of 25.4 million were valued at $51.7 million using the Company's share price on the closing date of the transaction of $2.04 per share.

On March 28, 2023, the Company issued 7.0 million flow-through shares at $2.85 per share, through a private placement for net proceeds of $19.6 million.

At March 10, 2025 there were 92.9 million common shares outstanding, net of 0.2 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, 2025**
Restricted share units	2,531
Share options	3,051
Performance share units	605
Perpetual awards(1)(2)	3,179
Total	**9,366**

(1) Perpetual awards from the Recombination Transaction include 1.2 million deferred options, 0.6 million deferred shares, 0.9 million share options and 0.5 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) Perpetual awards include 2.3 million of legacy awards that are settled outside of treasury.

Commodity price risk management

As at March 10, 2025, 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 ($/bbl)
Crude Oil	2,400 bbl/d	Jan 2025 - Mar 2025	WTI (US$/bbl)	Swap - sold	$74.41
Crude Oil	2,650 bbl/d	Apr 2025 - Jun 2025	WTI (US$/bbl)	Swap - sold	$72.23
Crude Oil	1,800 bbl/d	Jul 2025 - Sep 2025	WTI (US$/bbl)	Swap - sold	$71.98
Crude Oil	400 bbl/d	Oct 2025 - Dec 2025	WTI (US$/bbl)	Swap - sold	$74.86
Crude Oil	2,300 bbl/d	Jan 2025 - Mar 2025	WTI (CAD$/bbl)	Swap - sold	$99.54
Crude Oil	1,900 bbl/d	Apr 2025 - Jun 2025	WTI (CAD$/bbl)	Swap - sold	$99.16
Crude Oil	1,700 bbl/d	Jul 2025 - Sep 2025	WTI (CAD$/bbl)	Swap - sold	$99.12
Crude Oil	2,400 bbl/d	Jan 2025 - Mar 2025	WCS Differential (US$/bbl)	Swap - sold	($14.65)
Crude Oil	2,650 bbl/d	Apr 2025 - Jun 2025	WCS Differential (US$/bbl)	Swap - sold	($14.20)
Crude Oil	3,100 bbl/d	Jul 2025 - Sep 2025	WCS Differential (US$/bbl)	Swap - sold	($13.98)
Crude Oil	1,900 bbl/d	Oct 2025 - Dec 2025	WCS Differential (US$/bbl)	Swap - sold	($14.71)
Crude Oil	2,300 bbl/d	Jan 2025 - Mar 2025	WCS Differential (CAD$/bbl)	Swap - sold	($20.63)
Crude Oil	1,900 bbl/d	Apr 2025 - Jun 2025	WCS Differential (CAD$/bbl)	Swap - sold	($18.72)
Crude Oil	1,700 bbl/d	Jul 2025 - Sep 2025	WCS Differential (CAD$/bbl)	Swap - sold	($18.37)
Crude Oil	600 bbl/d	Jan 2025 - Mar 2025	WCS (CAD$/bbl)	Swap - sold	$79.69
Crude Oil	850 bbl/d	Apr 2025 - Jun 2025	WCS (CAD$/bbl)	Swap - sold	$80.19
Crude Oil	1,000 bbl/d	Jul 2025 - Sep 2025	WCS (CAD$/bbl)	Swap - sold	$80.48
Crude Oil	200 bbl/d	Oct 2025 - Dec 2025	WCS (CAD$/bbl)	Swap - sold	$80.00

As at March 10, 2025, Rubellite had entered into the following natural gas commodity risk management contracts:

Commodity	Volumes Sold	Term	Reference/Index	Contract Traded Bought/Sold	Average Price ($/GJ)
Natural gas	5,000 GJ/d	Jan 2025 - Mar 2025	AECO 5A (CAD$/GJ)	Swap - sold	$5.01
Natural gas	5,000 GJ/d	Apr 2025 - Oct 2025	AECO 5A (CAD$/GJ)	Swap - sold	$5.65
Natural gas	2,638 GJ/d	Apr 2025 - Oct 2025	AECO 7A / NYMEX Differential (US$/GJ)	Swap - bought	($2.56)
Natural gas	7,500 GJ/d	Nov 2025 - Dec 2025	AECO 5A (CAD$/GJ)	Swap - sold	$4.20
Natural gas	2,500 GJ/d	Jan 2026 - Mar 2026	AECO 5A (CAD$/GJ)	Swap - sold	$5.02

Foreign exchange risk management

As at March 10, 2025, Rubellite entered into the following foreign exchange risk management contracts:

Fixed Contract	Notional amount	Term	Price (CAD$/US$)
Average rate forward (CAD$/US$)	$4,361,000 US$/month	Jan - Mar 2025	1.3628
Average rate forward (CAD$/US$)	$3,950,000 US$/month	Apr - Jun 2025	1.3726
Average rate forward (CAD$/US$)	$3,403,000 US$/month	Jul - Sep 2025	1.3727
Average rate forward (CAD$/US$)	$1,300,000 US$/month	Oct - Dec 2025	1.3785
Average rate forward (CAD$/US$)	$2,500,000 US$/month	Jan - Dec 2026	1.4066

Variable Contract(1)	Notional amount	Term	Floor Price (CAD$/US$)	Ceiling Price (CAD$/US$)	Reset Price (CAD$/US$)
Knock-in Collar (CAD$/US$)	$500,000 US$/month	Jan - Dec 2025	1.3700	1.4375	1.3875
Knock-in Collar (CAD$/US$)	$500,000 US$/month	Jul - Dec 2025	1.3700	1.4300	1.4000
Knock-in Collar (CAD$/US$)	$2,500,000 US$/month	Jan - Dec 2026	1.3900	1.4670	1.4050

(1) If the monthly average exchange rate is below the floor price, settlement for that month will occur at the floor price. If the monthly average exchange rate is above the ceiling price, settlement for that month will be against the reset price. No settlement occurs when the monthly average exchange rate is between the floor and ceiling price.

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

The Company has a drilling commitment on certain GORR lands that must be fulfilled by June 30, 2026 (the "Commitment Date"). 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, 2024, the Company has drilled sixteen (16.0 net) of the 59 wells that are 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.

		December 31, 2024
Decommissioning obligations – current	$	2,000
Decommissioning obligations – non-current		29,817
Total decommissioning obligations	**$**	**31,817**

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

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

Other Provision

The Other Provision was assumed as part of the Recombination Transaction with Perpetual that closed on October 31, 2024. The other provision relates to a "Settlement Agreement" Perpetual entered into to resolve litigation whereby the Company will make annual installments payments of $3.75 million until the Settlement principal is paid. Subject to the payment of all amounts under the Settlement Agreement, interest prior to March 27, 2026 will accrue and be forgiven. As of March 28, 2026, interest will accrue and be payable on the outstanding Settlement Principal 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.

		December 31, 2024
Other provisions – current	$	3,750
Other provisions – non-current		14,824
Total other provisions	**$**	**18,574**

The following assumptions were used to estimate the Other Provision:

		December 31, 2024
Undiscounted obligations	$	19,941
Average risk-free rate		3.0%
Expected timing of settling obligations		5.3 years

OFF BALANCE SHEET ARRANGEMENTS

Rubellite has no material off balance sheet arrangements.

RELATED PARTY TRANSACTIONS

Until the Recombination Transaction in the fourth quarter of 2024, Rubellite and Perpetual were considered related parties due to the existence of the MSA. Further, certain officers and directors are key management of and have significant influence over Rubellite while also being key management of and having deemed control over Perpetual. Under the MSA, Rubellite reimbursed Perpetual for certain technical and administrative services provided to Rubellite split on a relative production basis. Effective June 1, 2024, the MSA was amended to split shared costs on a 80% Rubellite and 20% Perpetual basis. During the three and twelve months ending December 31, 2024, until the closing of the Recombination Transaction, Rubellite was billed by Perpetual for net transactions which were considered to be normal course of oil and gas operations totaling $1.2 million and $12.7 million (three and twelve months ended December 31, 2023 - $2.4 million and $6.9 million). Included within this amount were $0.5 million and $5.0 million (three and twelve months ended December 31, 2023 - $0.8 million and $3.4 million) of costs charged to Rubellite through the MSA by Perpetual prior the Recombination Transaction.

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.

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,	
	2024	2023	**2024**	2023
Net cash flows used in investing activities	**(49,633)**	(38,813)	**(173,030)**	(94,354)
Acquisitions	**—**	(33,173)	**(62,732)**	(33,173)
Dispositions	**—**	7,990	**—**	7,990
Change in non-cash working capital	**(14,096)**	12,689	**(1,392)**	2,359
Capital expenditures, including land, corporate and other	**(35,537)**	(26,319)	**(108,906)**	(71,530)
Property, plant and equipment additions	**(32,565)**	(13,231)	**(90,680)**	(43,660)
Exploration and evaluation additions	**(2,844)**	(13,088)	**(15,129)**	(27,870)
Corporate additions	**(128)**	—	**(3,097)**	—
Capital expenditures, including land, corporate and other	**(35,537)**	(26,319)	**(108,906)**	(71,530)

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,				Twelve months ended December 31,			
(*$ thousands, except per boe amounts*)		**2024**		2023		**2024**		2023
Net operating costs	**6.84**	**6,536**	5.66	2,191	**7.11**	**16,514**	6.12	7,371
Transportation	**6.01**	**5,747**	6.68	2,588	**7.03**	**16,328**	7.50	9,045
General and administrative	**3.69**	**3,522**	6.00	2,323	**4.57**	**10,616**	6.07	7,318
Cash finance expense	**2.91**	**2,784**	2.15	831	**2.97**	**6,904**	1.60	1,923
Cash costs	**19.45**	**18,589**	20.49	7,933	**21.68**	**50,362**	21.29	25,657

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 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 share and per boe amounts*)	**2024**	2023	**2024**	2023
Production and operating	**6,714**	2,191	**16,692**	7,371
Less: other income	**178**	—	**178**	—
Net operating costs	**6,536**	2,191	**16,514**	7,371
Per boe	**6.84**	5.66	**7.11**	6.12

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:

	As of December 31, 2024	As of December 31, 2023
Current assets	**44,714**	21,061
Current liabilities	**(74,680)**	(34,009)
Working capital deficit	**29,966**	12,948
Risk management contracts – current asset	**9,783**	8,796
Risk management contracts – current liability	**(2,765)**	—
Right of use liability - current liability	**(357)**	—
Share-based compensation liability - current liability	**(5,357)**	—
Decommissioning obligations – current liability	**(2,000)**	(77)
Other provision - current liability	**(3,750)**	—
Adjusted working capital deficit(1)	**25,520**	21,667
Bank indebtedness	**108,500**	29,317
Term loan (principal)	**20,000**	—
Net debt (2)	**154,020**	50,984

(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 decommissioning liabilities and other provisions.

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 and 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 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*)	**2024**	2023	**2024**	2023
Net cash flows from operating activities	**39,402**	18,963	**95,788**	55,391
Change in non-cash working capital	**(8,582)**	(2,040)	**(3,093)**	(1,237)
Cash-settled share-based compensation	**631**	—	**631**	—
Decommissioning obligations settled	**181**	—	**451**	3
Adjusted funds flow, after transaction costs	**31,632**	16,923	**93,777**	54,157
Transaction costs	**4,223**	147	**6,233**	147
Adjusted funds flow, before transaction costs	**35,855**	17,070	**100,010**	54,304
Adjusted funds flow per share - basic	**0.36**	0.27	**1.37**	0.90
Adjusted funds flow per share - diluted	**0.36**	0.27	**1.35**	0.89
Adjusted funds flow per boe	**33.10**	43.71	**40.35**	44.93
Adjusted funds flow per share - before transaction costs - basic	**0.41**	0.27	**1.46**	0.90
Adjusted funds flow per share - before transaction costs - diluted	**0.40**	0.27	**1.43**	0.89
Adjusted funds flow per boe - before transaction costs	**37.52**	44.09	**43.04**	45.06

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

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

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

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

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

Supplementary Financial Measures

"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

New Accounting Policies

On January 1, 2024 the Company adopted the amendments to IAS 1 *Presentation of Financial Statements* ("IAS 1") as issued by the IASB that clarify its requirements for the presentation of liabilities as current and non-current in the statement of financial position. In October 2022, the IASB issued further amendments to IAS 1, which specify the classification and disclosure of a liability with covenants. The adoption of this standard did not have a material impact on the Company's consolidated financial statements.

Future Accounting Pronouncements

In August 2023, the IASB issued amendments to IAS 21 *The effects of Changes in Foreign Exchange Rates* ("IAS 21") related the definition of exchangeable currency and provided further guidance on estimating the spot exchange rate when a currency is not exchangeable. These amendments will be effective on January 1, 2025, and are not expected to have a material impact on the Company's consolidated financial statements.

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.

Sustainability Disclosures

Emissions, carbon taxes and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social and governance ("ESG") and climate reporting, the IASB has issued an IFRS Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable.

On June 26, 2023, the International Sustainability Standards Board ("ISSB") issued IFRS S1 - *General Requirements for Disclosure of Sustainability Related Financial Information* ("IFRS S1"), and IFRS S2 - *Climate Related Disclosures* ("IFRS S2"). On March 13, 2024, the Canadian Sustainability Standards Board ("CSSB") released exposure drafts for two proposed standards; Canadian Sustainability Disclosure Standard 1 ("CSDS S1") - *General Requirements for Disclosure of Sustainability Related Financial Information* and Canadian Sustainability Disclosure Standard 2 ("CSDS S2") - *Climate Related Disclosures*. The CSSB provided a consultation period for comments on the proposed standards that expired on June 10, 2024 and a feedback statement was issued by the CSSB on October 31, 2024. The CSSB proposes that both CSDS S1 and CSDS S2 should be effective for annual periods beginning on or after January 1, 2025 but will not be mandatory. The sustainability standards as proposed by the CSSB provide for transition relief that allow for a reporting entity to report on climate only risks and opportunities and exclude scope 3 emissions in the first and second year of reporting and allow for a reporting timeline extension in the first year of reporting under the sustainability standards. Final versions of the CSDS S1 and CSDS S2 were approved in December 2024.

Canadian Security Regulators will begin their own consultation process to determine how the reporting standards will be translated into reporting requirements for reporting issuers and the timing for the implementation of such mandatory reporting requirements. The Company is monitoring the potential effects of the CSSB sustainability standards. At this time, Rubellite is not able to determine the impact on future financial statements or the potential costs to comply with these sustainability standards.

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:

- 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
- changes to government regulations including royalty regimes, tax legislation and tariffs.

Rubellite manages these risks by:

- 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 a flexible financial position;
- maintaining strict environmental, safety and health practices; and
- active participation with industry organizations to monitor and influence changes in government regulations and policies.

A complete discussion of risk factors is included in the Corporation's 2024 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

Rubellite'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") and internal controls over financial reporting ("ICOFR") as defined in National Instrument 52-109 Certification of Disclosure in Issuer's Annual and Interim Filings in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with IFRS.

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, 2024, 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, 2024 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, 2024, 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 internal control over financial reporting during the period beginning on October 1, 2024 and ended December 31, 2024 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

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 2024 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.

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, regulatory application and the benefits to be derived from such drilling including production growth; Rubellite's business plan; and including the information and statements contained under the heading "Outlook and Guidance" and "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 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), 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 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 Rubellite Energy Inc. and Perpetual

Energy Inc.'s Annual Information Form and MD&A for the year ended December 31, 2023 (and once filed under "Risk Factors" in Rubellite's Annual Information Form and MD&A for the year ended December 31, 2024) 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
boe/d	barrels of oil equivalent per day
Mcf	thousand cubic feet of natural gas
MMcf	million cubic feet
Mcf/d	thousand cubic feet of natural gas 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.

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.

Estimated Drilling Locations

Of the 414 net drilling locations disclosed in this MD&A 152.7 net are booked proved undeveloped ("PUD") and probable undeveloped ("PAUD") locations in the reserve report. Unbooked drilling locations are the internal estimates of Rubellite based on Rubellite's or the acquired assets prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by Rubellite's management as an estimation of Rubellite's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that Rubellite will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and natural gas reserves, resources or production. The drilling locations on which Rubellite will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been de-risked by Rubellite drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management of Rubellite has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

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)	**2024**	2023	2022
Financial			
Oil and natural gas revenue	**168,384**	88,968	54,491
Net income	**49,973**	18,561	24,605
Per share – basic(3)	**0.73**	0.31	0.47
Per share – diluted(3)	**0.72**	0.30	0.47
Total Assets	**562,612**	271,153	204,030
Cash flow from operating activities	**95,788**	55,391	23,870
Adjusted funds flow, after transaction costs(1)(6)	**93,777**	54,154	23,036
Per share – basic(2)(3)	**1.37**	0.90	0.44
Per share – diluted(2)(3)	**1.35**	0.89	0.44
Adjusted funds flow, before transaction costs(1)(6)	**100,010**	54,304	23,036
Per share – basic(2)(3)	**1.46**	0.90	0.44
Per share – diluted(2)(3)	**1.43**	0.89	0.44
Common shares (thousands)			
Weighted average – basic	**68,667**	60,346	52,093
Weighted average – diluted	**69,716**	61,075	52,471
Operating			
Heavy oil (bbl/d)(4)	**5,685**	3,302	1,670
Natural gas (Mcf/d)	**3,570**	—	—
NGL (bbl/d)(5)	**69**	—	—
Daily average sales production (boe/d)	**6,349**	3,302	1,670
Rubellite average realized prices(2)(7)			
Oil ($/bbl)	**78.92**	—	—
Natural Gas ($/Mcf)	**2.01**	—	—
NGL ($/bbl)	**61.32**	—	—
Total average realized price ($/boe)	**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) Conventional 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) Before risk management contracts; supplementary financial measure. See "Non-GAAP and Other Financial Measures".

SUMMARY OF QUARTERLY RESULTS

($ 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)(6)	**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
Capital expenditures, including land and other(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
Operating				
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 oil price(1)(7)				
Oil ($/bbl)	**76.97**	—	—	—
Natural gas ($/Mcf)	**2.01**	—	—	—
NGL ($/bbl)	**61.32**	—	—	—
Total average realized price ($/boe)	**61.83**	79.75	87.35	72.60

($ thousands, except as noted)	Q4 2023	Q3 2023	Q2 2023	Q1 2023
Financial				
Oil revenue	27,224	25,777	18,863	17,104
Net income and comprehensive income	9,523	3,942	3,397	1,699
Per share – basic(2)	0.15	0.06	0.05	0.03
Per share – diluted(2)	0.15	0.06	0.05	0.03
Total assets	271,153	223,353	218,218	222,747
Cash flow from (used in) operating activities	18,963	14,957	12,186	9,285
Adjusted funds flow, after transaction costs(1)(6)	16,923	15,554	11,998	9,682
Per share – basic(1)(2)	0.27	0.25	0.19	0.18
Per share – diluted(1)(2)	0.27	0.25	0.19	0.17
Capital expenditures, including land and other(1)	26,320	11,330	11,820	22,061
Acquisitions(3)	33,173	—	—	—
Dispositions(3)	(7,900)	—	—	—
Common shares (thousands)				
Weighted average – basic	62,440	61,956	61,830	55,060
Weighted average – diluted	62,958	62,597	62,432	55,550
Operating				
Daily average oil sales production (bbl/d)(4)	4,209	3,154	2,844	2,990
Rubellite average realized oil price(1)(7)				
Average realized oil price ($/bbl)	70.31	88.85	72.88	63.56

(1) Non-GAAP measure or ratio. 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) Conventional heavy oil sales production excludes tank inventory volumes.
(5) Liquids means oil, condensate, ethane, propane and butane.
(6) 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 and Q4 2023 includes $0.1 million in transaction costs related to the Clearwater Asset Acquisition.
(7) Before risk management contracts; supplementary financial measure. See "Non-GAAP and Other Financial Measures".

Oil and natural gas revenue has ranged between $17.1 million and $59.1 million over the prior eight quarters largely due to increasing sales volumes from 2,990 bbl/d to 10,386 bbl/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, 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. It examines the Company's financial performance in 2024 compared to 2023 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 Auditors' 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, 2025

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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, 2024 and December 31, 2023
- 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, 2024 and December 31, 2023, 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.

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, 2024. 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.

Evaluation of the preliminary acquisition date fair value of oil and gas interests and deferred tax asset (DTA) acquired as part of the Perpetual Energy Inc. ("Perpetual") recombination transaction

Description of the matter

We draw attention to note 2, note 3, note 4, and note 15 to the financial statements. Effective October 31, 2024, the Entity and Perpetual effected a recombination transaction by way of an arrangement resulting in the recombination of the two entities ("recombination transaction"). The recombination transaction has been accounted for as a business combination using the acquisition method of accounting, whereby the assets acquired and the liabilities assumed are recorded at their estimated fair value on the acquisition date of October 31, 2024. 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. In connection with the recombination transaction, the Entity recorded a preliminary acquisition date fair value of the oil and gas interests of $63.0 million and a DTA of $31.6 million.

The determination of the preliminary acquisition date fair value of oil and gas interests involves significant estimates and assumptions, including:

- The cash flows associated with the estimate of proved and probable oil and gas reserves
- The discount rates

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

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

To estimate the preliminary acquisition date fair value of the acquired oil and gas interests, the Entity used cash flow estimates from December 31, 2023, prepared by independent third-party reserve evaluators. These cash flow estimates were updated by internal reserve evaluators to reflect activity and commodity price assumptions up to October 31, 2024. Additionally, the Entity engaged independent third-party reserve evaluators to estimate proved and probable reserves as of December 31, 2024.

Why the matter is a key audit matter

We identified the preliminary acquisition date fair value of oil and gas interests and DTA acquired as part of the Perpetual recombination transaction 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 evaluation of the preliminary acquisition date fair value of the oil and gas interests and measurement of the DTA acquired requires the use of professionals with specialized skills and knowledge in valuation and tax.

How the matter was addressed in the audit

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

With respect to the estimate of proved and probable oil and gas reserves at October 31, 2024:

- We evaluated the competence, capabilities and objectivity of the internal reserve evaluators
- We compared forecasted oil and gas commodity prices to those published by other independent third-party reserve evaluators
- We evaluated the appropriateness of the estimate of cash flows from proved and probable oil and gas reserves as at October 31, 2024 for forecasted production, operating costs, royalty costs and future development costs by comparing them to the corresponding amounts from proved and probable oil and gas reserves estimated by the independent third-party reserve evaluators as at December 31, 2024. We took into account changes in conditions and events affecting the Entity to assess the adjustments or lack of adjustments between October 31, 2024 and December 31, 2024

With respect to the estimate of proved and probable oil and gas reserves as at December 31, 2024:

- 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 2024 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 2024 historical results of the acquired oil and natural gas properties post acquisition. 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 assessed the recognition and measurement of the DTA for compliance with IFRS Accounting Standards.

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

- Evaluating the appropriateness of the discount rates by comparing the discount rate to market and other external data

- Assessing the appropriateness of the Entity's estimated preliminary acquisition date fair value of the oil and natural gas interests acquired in a business combination by comparing the Entity's estimate to market metrics and other external data

We involved income tax professionals with specialized skills and knowledge who assisted in evaluating the application of relevant tax laws and regulations and the appropriateness of the Entity's estimate of future taxable profits used in the measurement of the DTA.

Evaluation of the acquisition date fair value of oil and gas interests acquired as part of the Buffalo Mission Energy Corp. ("Buffalo Mission") business combination

Description of the matter

We draw attention to note 2, note 3, and note 4 to the financial statements. Effective August 2, 2024, the Entity acquired all of the issued and outstanding common shares of Buffalo Mission (the "Acquisition"). The Acquisition has been accounted for as a business combination using the acquisition method of accounting, whereby the assets acquired and the liabilities assumed are recorded at their estimated fair value on the acquisition date of August 2, 2024. In connection with the Acquisition, the Entity recorded a preliminary acquisition date fair value of the oil and gas interests of $110.8 million.

The determination of the acquisition date fair value of oil and gas interests involves significant estimates and assumptions, including:

- The cash flows associated with the estimate of proved and probable oil and gas reserves
- The discount rates

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

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

For purposes of estimating the acquisition date fair value of the oil and gas interests acquired, the Entity engaged independent third-party reserve evaluators to provide an estimate of the proved and probable oil and gas reserves as at August 2, 2024 and December 31, 2024.

Why the matter is a key audit matter

We identified the evaluation of the acquisition date fair value of oil and gas interests acquired as part of the Buffalo Mission business combination 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 evaluation of the acquisition date fair value of the oil and gas interests acquired 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:

With respect to the estimate of proved and probable oil and gas reserves at August 2, 2024:

- 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 evaluated the appropriateness of the estimate of cash flows from proved and probable oil and gas reserves as at August 2, 2024 by comparing them to the corresponding cash flows from proved and probable oil and gas reserves estimated by the independent third-party reserve evaluators as at December 31, 2024. We took into account changes in conditions and events affecting the Entity to assess the adjustments or lack of adjustments between August 2, 2024 and December 31, 2024.

With respect to the estimate of proved and probable oil and gas reserves as at December 31, 2024:

- 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 2024 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 2024 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 discount rates by comparing the discount rate to market and other external data

Assessing the reasonableness of the Entity's estimated acquisition date fair value of the oil and natural gas interests acquired in the Buffalo Mission business combination by comparing the Entity's estimate to market metrics and other external data.

Assessment of the impact of estimated proved and probable oil and gas reserves on property, plant and equipment (“PP&E”) and the deferred tax asset (“DTA”)

Description of the matter

We draw attention to note 2, note 3, note 5, note 6, and note 15 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 (“CGU”) 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 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 DTA. 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.

The Entity has $456.7 million of Development and Production Assets as of December 31, 2024.

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 $50.3 million for the year ended December 31, 2024.

The Entity recognized a deferred tax asset of $21.4 million at December 31, 2024. The determination of probable future taxable profits involves significant estimates, including proved and probable oil and gas reserves.

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 PP&E and the DTA 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. Additionally, the measurement of the DTA requires the use of professionals with specialized skills and knowledge in tax.

KPMG

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 calculation and measurement of the DTA for compliance with IFRS Accounting Standards.

With respect to the estimate of proved and probable oil and gas reserves as at December 31, 2024:

- 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 2024 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 2024 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 income tax professionals with specialized skills and knowledge who assisted in evaluating the application of relevant tax laws and regulations and the appropriateness of the Entity's estimate of future taxable profits used in the measurement of the DTA.

Other Information

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

- the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.
- the information, other than the financial statements and the auditor's report thereon, included in a document likely to be entitled "2024 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 filed with the relevant Canadian Securities Commissions 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 “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.

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

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
March 10, 2025

RUBELLITE ENERGY CORP.
Consolidated Statements of Financial Position

As at	December 31, 2024	December 31, 2023
(*Cdn$ thousands*)		
Assets		
Current assets		
Cash	**$ 2,555**	$ —
Accounts receivable	**26,349**	10,830
Prepaid expenses, deposits and other	**2,752**	433
Product inventory	**3,275**	1,002
Risk management contracts (note 18c)	**9,783**	8,796
	44,714	21,061
Property, plant and equipment (note 4, 5)	**461,996**	202,203
Exploration and evaluation (note 4a, 6)	**29,106**	32,301
Right-of-use asset (note 7)	**4,930**	—
Deferred tax asset (note 15)	**21,437**	15,043
Risk management contracts (note 18c)	**429**	545
Total assets	**$ 562,612**	$ 271,153
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 60,451**	$ 33,932
Risk management contracts (note 18c)	**2,765**	—
Lease liabilities (note 9)	**357**	—
Share-based compensation liability (note 11)	**5,357**	—
Other provision (note 8b)	**3,750**	—
Decommissioning obligations (note 8a)	**2,000**	77
	74,680	34,009
Bank debt (note 13)	**108,500**	29,317
Term loan (note 14)	**19,027**	—
Lease liabilities (note 9)	**4,608**	—
Risk management contracts (note 18c)	**225**	—
Share-based compensation liability (note 11)	**914**	—
Other provision (note 8b)	**14,824**	—
Decommissioning obligations (note 8a)	**29,817**	8,516
Total liabilities	**252,595**	71,842
Equity		
Share capital (note 10b)	**206,313**	143,033
Share purchase warrants (note 10b)	**—**	2,000
Contributed surplus (note 11)	**2,863**	3,410
Retained earnings	**100,841**	50,868
Total equity	**310,017**	199,311
Total liabilities and equity	**$ 562,612**	$ 271,153

Commitments (note 21)
Subsequent events (note 1, 18c)

See accompanying notes to the consolidated financial statements.

Holly Benson

Holly Benson
Director

Linda Dietsche
Director

RUBELLITE ENERGY CORP.
Consolidated Statements of Income and Comprehensive Income

	December 31, 2024	December 31, 2023
(Cdn$ thousands, except per share amounts)		
Revenue		
Oil and natural gas (note 12)	**$ 168,384**	$ 88,968
Royalties	**(20,272)**	(8,513)
	148,112	80,455
Realized gain (loss) on risk management contracts (note 18c)	**2,582**	(318)
Unrealized gain (loss) on risk management contracts (note 18c)	**(12,252)**	8,652
Other income	**178**	—
	138,620	88,789
Expenses		
Production and operating	**16,692**	7,371
Transportation	**16,328**	9,045
General and administrative	**10,616**	7,318
Share based payments (note 11)	**3,571**	3,041
Exploration and evaluation (note 6)	**541**	7,018
Gain on acquisitions and dispositions (note 4)	**(31,617)**	(1,290)
Depletion and depreciation (note 5)	**49,847**	27,485
Transaction costs (note 4)	**6,233**	147
	66,409	28,654
Finance expense (note 16)	**(7,376)**	(2,051)
Income before income tax	**59,033**	26,603
Taxes		
Deferred tax expense (note 15)	**(9,060)**	(8,042)
Net income and comprehensive income	**$ 49,973**	$ 18,561
Net income per share (note 10c)		
Basic	**$ 0.73**	$ 0.31
Diluted	**$ 0.72**	$ 0.30

See accompanying notes to the consolidated financial statements.

RUBELLITE ENERGY CORP.
Consolidated Statements of Changes in Equity

	Share Capital (*thousands*)	*Share Capital* (*$thousands*)	Share purchase warrants	Contributed surplus	Retained earnings	Total Equity
(Cdn$ 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 4a, 10b)	30,359	61,713	—	—	—	61,713
Common shares issued, share-based payment plan (note 10b)	229	1,567	—	(2,140)	—	(573)
Cancellation of share purchase warrants (note 10b)	—	—	(2,000)	2,000	—	—
Reclassification of share-based compensation liability (note 11)	—	—	—	(3,696)	—	(3,696)
Share-based payments (note 11)	—	—	—	3,289	—	3,289
Balance at December 31, 2024	**93,044**	**$ 206,313**	**$ —**	**$ 2,863**	**$100,841**	**$310,017**

	Share Capital (*thousands*)	*Share Capital* (*$thousands*)	Share purchase warrants	Contributed surplus	Retained earnings	Total Equity
(Cdn$ thousands, except share amounts)						
Balance at December 31, 2022	54,826	$ 123,383	$ 2,000	$ 1,805	$ 32,307	$ 159,495
Net income	—	—	—	—	18,561	18,561
Flow-through shares issued, net of issue costs (note 10)	7,000	19,754	—	—	—	19,754
Deferred premium on flow-through shares (note 10)	—	(1,540)	—	—	—	(1,540)
Common shares issued, share-based payment plan (note 10)	630	1,436	—	(1,436)	—	—
Share-based payments (note 11)	—	—	—	3,041	—	3,041
Balance at December 31, 2023	**62,456**	**$ 143,033**	**$ 2,000**	**$ 3,410**	**$ 50,868**	**$199,311**

See accompanying notes to the consolidated financial statements.

RUBELLITE ENERGY CORP.
Consolidated Statements of Cash Flows

(*Cdn$ thousands*)	**December 31, 2024**	December 31, 2023
Cash flows from operating activities		
Net income	**$ 49,973**	$ 18,561
Adjustments to add (deduct):		
Depletion and depreciation (note 5)	**49,847**	27,485
Share-based payments (note 11)	**3,571**	3,041
Gain related to deferred tax on acquisition (note 4a)	**(31,617)**	—
Deferred tax expense (note 15)	**9,060**	8,042
Unrealized (gain) loss on risk management contracts (note 18c)	**12,252**	(8,652)
Non-cash finance expense (note 16)	**472**	128
Gain on dispositions (note 4b)	**—**	(1,290)
Exploration and evaluation expense (note 6)	**220**	6,842
Payment for share-based compensation (note 11)	**(632)**	—
Decommissioning obligations settled (note 8a)	**(451)**	(3)
Change in non-cash working capital (note 17)	**3,093**	1,237
Net cash flows from operating activities	**95,788**	55,391
Cash flows from financing activities		
Common shares issued, net of fees	**(624)**	19,950
Term loan, net of issue costs (note 14)	**18,964**	(254)
Payment lease liabilities (note 9)	**(71)**	—
Repayment of acquired bank debt (note 4a)	**(14,215)**	—
Change in bank debt (note 13)	**75,743**	17,317
Net cash flows from financing activities	**79,797**	37,013
Cash flows used in investing activities		
Development and production asset expenditures (note 5)	**(90,680)**	(43,660)
Corporate expenditures (note 5)	**(3,097)**	—
Exploration and evaluation expenditures (note 6)	**(15,129)**	(27,870)
Acquisitions (note 4)	**(62,732)**	(33,173)
Proceeds from dispositions (note 4b)	**—**	7,990
Change in non-cash working capital (note 17)	**(1,392)**	2,359
Net cash flows used in investing activities	**(173,030)**	(94,354)
Change in cash and cash equivalents	**2,555**	(1,950)
Cash and cash equivalents, beginning of year	**—**	1,950
Cash and cash equivalents, 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. 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").

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, 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. The consolidated financial statements presented for the year ended December 31, 2023 represent the results of Rubellite Energy Inc. and its wholly owned subsidiaries Ukalta GP Inc. and Ukalta Limited Partnership. 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, 2025.

a) Critical accounting judgements and significant estimates

The preparation of the consolidated financial statements in conformity with IFRS Accounting Standards requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenue and expenses. These judgments, 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 judgments that management has made in the process of applying the Company's accounting policies. These judgments 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.

ii) Identification of impairment indicators

Significant judgment 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 judgment 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

Judgment 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, judgment 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 judgment 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, 2024.

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 managements 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 the 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 share-based compensation plans were 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 ("NGLs") 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) Flow-through shares

Flow-through shares permit an investor to claim deductions for tax purposes related to qualifying expenditures incurred by the issuer. The issuer renounces the right to claim the income tax deductions in favor of the investor. Proceeds from the issuance are presented net of directly attributable share issuance costs.

Proceeds from the issuance of flow-through shares are allocated between the offering of shares and the sale of tax benefits when the shares are offered. The allocation is made based on the difference between the quoted price of the existing shares and the amount the investor pays to acquire the flow-through shares, with a deferred liability being recognized for the difference. The liability is drawn down as the qualifying expenditures are incurred with a deferred tax liability recognized equal to the deferred tax payable. Any difference between the draw down of the deferred liability set up for the premium on the flow-through shares and the deferred tax effect on the expenditures is recognized in the consolidated statements of income and comprehensive income.

n) 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.

o) Changing Regulation

Emissions, carbon taxes and other regulations regarding climate-related matters are constantly evolving. With respect to environmental, social and governance and climate reporting, the IASB has issued an IFRS Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators have issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters. The Canadian Sustainability Standards Board ("CSSB") released final versions of the sustainability standards in December 2024. The Canadian Securities Administrators will begin their own consultation process to determine how the reporting standards will be transitioned into reporting requirements for reporting issuers and the timing of such implementation. The Company is evaluating the potential effects of the CSSB sustainability standards, and at this time, is not able to determine the impact on future financial statements. The cost to comply with these standards and others that may be developed over time has not yet been quantified.

p) New Accounting Standards

On January 1, 2024 the Company adopted the amendments to IAS 1 *Presentation of Financial Statements* ("IAS 1") as issued by the IASB that clarify its requirements for the presentation of liabilities as current and non-current in the statement of financial position. In October 2022, the IASB issued further amendments to IAS 1, which specify the classification and disclosure of a liability with covenants. The adoption of this standard did not have a material impact on the Company's consolidated financial statements.

q) Future Accounting Pronouncements

In August 2023, the IASB issued amendments to IAS 21 *The effects of Changes in Foreign Exchange Rates* ("IAS 21") related the definition of exchangeable currency and provided further guidance on estimating the spot exchange rate when a currency is not exchangeable. These amendments will be effective on January 1, 2025, and are not expected to have a material impact on the Company's consolidated financial statements.

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. ACQUISITIONS AND DISPOSITIONS

a) 2024 Acquisitions

Perpetual Energy Inc. ("Perpetual")

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., creating a larger, financial stronger company with increased free funds flow, enhanced liquidity and a well defined growth profile. 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 is 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. is the acquirer for accounting purposes resulting in the Recombination Transaction being accounted for in accordance with IFRS 3 *Business Combinations*.

The Recombination Transaction has been 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 which were expensed through the consolidated statement of income and comprehensive income. The conventional natural gas assets acquired in this transaction are 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 10b).

The following preliminary purchase price is based on management's estimates of fair values, which is subject to change, is as follows:

Assets acquired		
Oil and natural gas interests (note 5)	$	63,038
Net working capital deficiency (note 17)		(6,356)
Right-of-use asset (note 7)		5,036
Exploration and evaluation assets (note 6)		2,692
Corporate assets (note 5)		2,737
Risk management contracts (note 18c)		10,132
Lease liability (note 9)		(5,036)
Share-based compensation liability (note 11)		(2,925)
Other provision (note 8b)		(18,481)
Decommissioning provisions (note 8a)		(3,128)
Deferred tax asset (note 15)		31,569
Gain on acquisition (note 15)		(31,569)
Net assets acquired	**$**	**47,709**

Consideration		
Shares (note 10b)		51,732
Settlement of pre-existing relationship(1)	$	(4,023)
Total consideration paid	**$**	**47,709**

(1) Until the Recombination Transaction, 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.

Results from the operations of Perpetual are included in the Company's consolidated financial statements from the closing date of the acquisition. The estimated 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 estimated 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%.

Oil and natural gas revenue of $4.2 million and net income of $1.8 million are included in the consolidated statements of income and comprehensive income since the closing of the Recombination Transaction on October 31, 2024. If the Recombination Transaction had occurred on January 1, 2024 the estimated incremental oil and natural gas revenue and net income would have been $24.3 million and $11.0 million, respectively.

Buffalo Mission Energy Corp. ("Buffalo Mission")

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 10b) 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"). Rubellite funded the transaction through; an expanded credit facility which increased from $60.0 million to $100.0 million (note 13), a $20.0 million bank syndicate term loan which was repaid on October 31, 2024 (note 13), and a new second lien term loan ("Term Loan") placed, directly or indirectly, with certain directors and officers of Rubellite and the Company's significant shareholder for $20.0 million which bears interest at 11.5% (note 14).

The BMEC Acquisition has been 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 August 2, 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 are included in the Eastern Heavy Oil CGU.

The purchase price, based on management's estimates of fair values, is as follows:

Assets acquired		
Oil and gas interests (note 5)	$	110,780
Net working capital deficiency[1]		(21,204)
Deferred tax liabilities (note 15)		(15,795)
Decommissioning provisions (note 8a)		(699)
Net assets acquired	**$**	**73,082**
Consideration		
Cash	$	62,732
Share (note 10b)		10,350
Total consideration paid	**$**	**73,082**

(1) Assumed net debt excluded inventory and other items which are included in net working capital.

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 engaged its independent third-party reserve evaluator to provide 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%.

Oil and gas revenue of $26.3 million and net income of $15.2 million are 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 revenues would have been $37.3 million and estimated net income would have been $22.9 million.

b) 2023 Acquisitions and Dispositions

Acquisitions

Effective November 8, 2023, Rubellite acquired Clearwater assets within the Greater Figure Lake area, as well as undeveloped land in the Calling Lake area of Northeast Alberta for net cash proceeds of $33.2 million. The acquisition was accounted for as a business combination using the acquisition method of accounting, whereby the assets acquired and the liabilities assumed are recorded at their estimated fair value on the acquisition date of November 8, 2023. Rubellite incurred transaction costs of $0.1 million which have been recognized in the consolidated statements of income and comprehensive income. All of the assets acquired were included within the Company's Eastern Heavy Oil CGU.

The preliminary purchase price, based on management's estimates of fair values, is as follows:

Assets acquired		
Oil and gas interests (note 5)	$	29,032
Exploration and evaluation assets (note 6)		4,526
Decommissioning provisions (note 8a)		(385)
Net assets acquired	**$**	**33,173**
Consideration		
Cash	$	33,173
Total consideration paid	**$**	**33,173**

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 preliminary acquisition date fair value of the oil and gas interests acquired, the Company engaged its independent third-party reserve evaluator to provide an estimate of proved and probable oil and gas reserves both as at October 1, 2023 and December 31, 2023. Management took into account production, conditions and events to assess adjustments to the estimated reserve value both at October 1, 2023 and December 31, 2023 as compared to the estimated reserves at November 8, 2023. Exploration and evaluation assets were fair valued based on an internally prepared report reflecting the estimated market value of undeveloped land. 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 11.7%. The purchase price allocation is not final as the Company continues to obtain and verify the information required to finalize the fair value of the oil and gas interests acquired.

Oil and gas revenue of $2.5 million and net income of $1.5 million are included in the consolidated statements of income and comprehensive income since the closing of the acquisition on November 8, 2023. If the acquisition had occurred on January 1, 2023 the estimated contributed revenues would have been $10.5 million and estimated net income before tax would have been $6.5 million.

Dispositions

On December 4, 2023 the Company disposed of a 1.5% non-convertible gross overriding royalty ("GORR"), which reverts to a 1.0% GORR after payout for cash consideration of $8.0 million. A gain of $1.3 million was recorded in the consolidated statements of income and comprehensive income.

5. PROPERTY, PLANT AND EQUIPMENT

	Development and Production Assets	Corporate Assets	Total
Cost			
December 31, 2022	$ 151,309	$ —	$ 151,309
Additions	43,660	—	43,660
Transfer from exploration and evaluation (note 6)	22,606	—	22,606
Acquisitions (note 4b)	28,647	—	28,647
Dispositions (note 4b)	(5,801)	—	(5,801)
Change in decommissioning obligations related to PP&E (note 8a)	4,735	—	4,735
December 31, 2023	$ 245,156	$ —	$ 245,156
Additions(1)	**90,680**	**3,097**	**93,777**
Transfer from exploration and evaluation (note 6)	**20,796**	**—**	**20,796**
Acquisitions (note 4a)(2)	**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**
Accumulated depletion and depreciation			
December 31, 2022	$ (15,360)	$ —	$ (15,360)
Depletion	(27,593)	—	(27,593)
December 31, 2023	$ (42,953)	$ —	$ (42,953)
Depletion and depreciation(3)	**(50,317)**	**(550)**	**(50,867)**
December 31, 2024	**$ (93,270)**	**$ (550)**	**$ (93,820)**
Carrying amount			
December 31, 2023	$ 202,203	$ —	$ 202,203
December 31, 2024	**$ 456,712**	**$ 5,284**	**$ 461,996**

(1) In Q2 2024, prior to the Recombination Transaction, $2.8 million of corporate assets (December 31, 2023 - nil) related to leasehold improvements for the shared office space under the Management and Operating Services Agreement ("MSA") were recorded as additions to PP&E (note 20).
(2) Included in corporate assets acquired from Perpetual in the Recombination Transaction are $2.7 million (December 31, 2023 - nil) related to the Company's corporate office space (note 4a) that were previously shared under the MSA.
(3) During the year ended December 31, 2024, depletion included $1.1 million which has been capitalized to inventory (December 31, 2023 - $0.6 million).

As at December 31, 2024, future development costs of $436.3 million (December 31, 2023 – $145.1 million) associated with proved and probable oil and gas reserves were included in the depletion calculation and an estimated $8.7 million (December 31, 2023 – $3.4 million) of salvage value for production equipment and $7.2 million (December 31, 2023 - nil) related to assets under construction were excluded as the assets were not substantially complete and ready for their intended use as at December 31, 2024. Depletion expense was $50.3 million (December 31, 2023 - $27.6 million) on development and production assets for the year ended December 31, 2024.

During the year ended December 31, 2024, the Company added $5.8 million of corporate assets (December 31, 2023 - nil) and recorded depreciation expense of $0.6 million (December 31, 2023 - nil).

a) Impairment

There were no indicators of impairment related to the Company's CGUs as at December 31, 2024 and December 31, 2023.

During 2024, the Company transferred $20.8 million of E&E to PP&E. The Company performed the required impairment test and determined that the recoverable amount of the CGU exceeded its carrying value, resulting in no impairment.

The Company transferred $22.6 million of E&E to PP&E during 2023 and performed the required impairment test. It was determined that the recoverable amount of the CGU exceeded its carrying value, resulting in no impairment in 2023.

6. EXPLORATION AND EVALUATION

	December 31, 2024	December 31, 2023
Balance, beginning of year	**$ 32,301**	$ 30,252
Acquisitions (note 4a, 4b)	**2,692**	4,526
Dispositions (note 4b)	**—**	(899)
Additions	**15,129**	27,870
Transfer to property, plant, and equipment (note 5)	**(20,796)**	(22,606)
Exploration and evaluation expense	**(220)**	(6,842)
Balance, end of year	**$ 29,106**	$ 32,301

During the year ended December 31, 2024, $0.5 million (December 31, 2023 - $7.0 million) was charged to exploration and evaluation ("E&E") expense in the consolidated statements of income and comprehensive income. This includes $0.2 million related to land expiries previously recorded as E&E (December 31, 2023 - $6.8 million of exploration drilling previously recorded to E&E).

Impairment of E&E assets

E&E assets are tested for impairment when internal or external indicators of impairment exist as well as upon reclassification to oil and gas interests in PP&E. At December 31, 2024, the Company conducted an assessment of indicators of impairment for the Company's E&E assets. In performing the assessment, management has determined that there were no indicators of impairment.

7. RIGHT-OF-USE ASSETS

The Company leases several assets including office space, vehicles, and other leases, which were assumed from Perpetual in the Recombination Transaction (see note 4a). Information about leases for which the Company is a lessee is presented below:

	Head office	Vehicles	Other leases	Total
Cost				
December 31, 2023	$ —	$ —	$ —	$ —
Acquisitions (note 4a)	4,782	190	64	5,036
December 31, 2024	**$ 4,782**	**$ 190**	**$ 64**	**$ 5,036**
Accumulated depreciation				
December 31, 2023	$ —	$ —	$ —	$ —
Depreciation	(77)	(23)	(6)	(106)
December 31, 2024	**$ (77)**	**$ (23)**	**$ (6)**	**$ (106)**
Carrying amount				
December 31, 2023	$ —	$ —	$ —	$ —
December 31, 2024	**$ 4,705**	**$ 167**	**$ 58**	**$ 4,930**

8. PROVISIONS

a) Decommissioning Obligations

The following table summarizes changes in decommissioning obligations:

	December 31, 2024	December 31, 2023
Balance, beginning of year	**$ 8,593**	$ 3,733
Liabilities settled	**(451)**	(3)
Obligations incurred	**3,535**	2,143
Obligations acquired (note 4a, 4b)	**3,827**	385
Change in rate on acquisition (note 4a, 4b)(1)	**13,586**	1,611
Revisions to estimates	**2,411**	596
Accretion (note 16)	**316**	128
Total decommissioning obligations, end of year	**$ 31,817**	$ 8,593
Decommissioning obligations - current	**$ 2,000**	$ 77
Decommissioning obligations - non-current	**29,817**	8,516
Total decommissioning obligations	**$ 31,817**	$ 8,593

(1) The decommissioning obligations acquired were initially valued using a credit adjusted risk-free rate of 11.5% on the acquisition date and revalued at December 31, 2024 using a risk free rate of 3.3%.

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, 2024	December 31, 2023
Undiscounted obligations	**$ 42,085**	$ 11,443
Average risk-free rate	**3.3%**	3.0%
Inflation rate	**1.8%**	1.6%
Expected timing of settling obligations	**1 to 25 years**	1 to 25 years

b) Other Provision

	December 31, 2024	December 31, 2023
Balance, beginning of year	$ —	$ —
Provision acquired (note 4a)	18,481	—
Accretion (note 16)	93	—
Total other provision, end of year	**$ 18,574**	$ —
Other provision - current	$ 3,750	$ —
Other provision - non-current	14,824	—
Total other provision	**$ 18,574**	$ —

The other provision was assumed as part of the Recombination Transaction. The provision relates to a "Settlement Agreement" Perpetual entered into to resolve litigation by providing amounts to settle asset retirement obligations related to the estate of Sequoia Resources Corp. The Company will make annual installment payments of $3.75 million on March 27 of each year until the outstanding Settlement Principal of $19.9 million is paid. Subject to the payment of all amounts under the Settlement Agreement, interest prior to March 27, 2026 will be forgiven. As of March 28, 2026, interest will accrue and be payable on the outstanding Settlement Principal 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, 2024
Undiscounted obligations	$ 19,941
Average risk-free rate	3.0%
Expected timing of settling obligations	5.3 years

9. LEASE LIABILITIES

The lease liability was assumed as part of the Recombination Transaction with Perpetual (note 4a) and relates to several leased assets including office space, vehicles, and other leases.

The following table summarizes changes in lease liabilities:

	December 31, 2024	December 31, 2023
Balance, beginning of year	$ —	$ —
Acquisition (note 4a)	5,036	—
Interest on lease liabilities (note 16)	55	—
Payments	(126)	—
Total lease liabilities	**$ 4,965**	$ —
Current	$ 357	$ —
Non-current	4,608	—
Total lease liabilities	**$ 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 the date of acquisition were between 4.3% and 6.6% (December 31, 2023 - nil).

10. SHARE CAPITAL

a) Authorized

Authorized capital consists of an unlimited number of common shares.

b) Issued and outstanding

	December 31, 2024		December 31, 2023	
	Shares *(thousands)*	**Amount *($thousands)***	Shares *(thousands)*	Amount *($thousands)*
Balance, beginning of year	**62,456**	**$ 143,033**	54,826	$ 123,383
Flow-through shares issued pursuant to private placement	**—**	**—**	7,000	19,950
Deferred premium on flow-through shares	**—**	**—**	—	(1,540)
Common shares issued, net of issue costs (note 4a)	**30,359**	**62,082**	—	—
Issued pursuant to share-based plans	**229**	**1,567**	630	1,436
Share issue costs(1)	**—**	**(369)**	—	(196)
Balance, end of year	**93,044**	**$ 206,313**	62,456	$ 143,033

(1) Share issue costs for the year ended December 31, 2024 are net of $0.3 million of deferred tax (December 31, 2023 - $0.1 million).

On October 31, 2024, in conjunction with the closing of the Recombination Transaction (note 4a), Rubellite issued 25.4 million common shares which consisted of 11.6 million common shares issued to the holders of Perpetual senior notes based on a share conversion price of $2.25 per share and 13.7 million common shares issued to holders of Perpetual common shares on the closing date of the Recombination Transaction. The common shares issued of 25.4 million 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 BMEC Acquisition (note 4a), Rubellite issued 5.0 million common shares to certain shareholders of Buffalo Mission, which were valued at $10.4 million using Rubellite Energy Inc.'s share price on the closing date of the transaction of $2.07 per share.

At December 31, 2023, there were 4.0 million Rubellite common share purchase warrants exercisable at $3.00 per share with an expiry in September 2026.

On March 28, 2023, the Company issued 7.0 million flow-through shares at $2.85 per share, through a private placement for gross proceeds of $20.0 million. Certain directors and officers of the Company subscribed for $13.3 million of the flow-through shares issued. Rubellite incurred share issuance costs of $0.2 million, net of deferred taxes.

c) Per share information

(thousands, except per share amounts)	**December 31, 2024**	December 31, 2023
Net income	**$ 49,973**	$ 18,561
Weighted average shares		
Issued common shares	**93,044**	62,456
Effect of shares held in trust	**(167)**	—
Issued common shares, net of shares held in trust(1)	**92,877**	62,456
Weighted average common shares outstanding – basic	**68,667**	60,346
Weighted average common shares outstanding – diluted	**69,716**	61,075
Net income per share – basic	**$ 0.73**	$ 0.31
Net income per share – diluted	**$ 0.72**	$ 0.30

(1) As result of the Recombination Transaction (note 4a), 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 11). Share capital is presented net of the shares held by the Trustee that have not been issued to employees. As at December 31, 2024 there were $0.2 million shares held in trust (December 31, 2023 - nil).

Per share amounts have been calculated using the weighted average number of common shares outstanding. For the year ended December 31, 2024, 8.3 million common shares (December 31, 2023 - 7.0 million common shares) issuable upon the exercise and/or settlement of warrants, share options, restricted share units and performance share units were excluded from the diluted weighted average number of common shares outstanding as they were anti-dilutive.

11. SHARE-BASED PAYMENTS

Previously, awards issued had been accounted for as equity-settled under IFRS 2 *Share-based Payment*. During the year ended December 31, 2024, the Company modified its share-based payment awards from equity-settled to cash-settled. As a result of this modification to the Company's outstanding share options, performance share units and restricted share units have been modified from equity-settled to cash-settled accounting and the fair value of the awards previously expensed has been reclassified from contributed surplus to share-based compensation liabilities. Subsequent to the modification, the grant date fair value is used to record the cost of the share options and any subsequent measurement of the liability is recognized in the consolidated statement of income and comprehensive income.

Share-based payment awards that were included as part of the Recombination Transaction with Perpetual (note 4a) 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, 2024	December 31, 2023
Balance, beginning of year	**$ —**	$ —
Reclassified from contributed surplus	**3,696**	—
Share-based compensation liability acquired (note 4a)	**2,925**	—
Fair value adjustment	**282**	—
Cash settlements	**(632)**	—
Balance, end of year	**$ 6,271**	$ —
Share-based compensation liability - current	**$ 5,357**	$ —
Share-based compensation liability - non-current	**914**	—
Total share-based compensation liabilities	**$ 6,271**	$ —

The components of share-based compensation expense are as follows:

	December 31, 2024	December 31, 2023
Share options	**$ 993**	$ 1,109
Restricted share units	**963**	718
Performance share units	**1,333**	1,214
Fair value adjustment	**282**	—
Share-based payment expense	**$ 3,571**	$ 3,041

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

Compensation awards

(number of awards, thousands)	**Share options**	**Performance share units**	**Restricted share units**	**Total**
December 31, 2023	2,696	464	530	3,690
Granted	395	492	2,333	3,220
Exercised for common shares	(17)	(351)	(85)	(453)
Exercised for cash(1)	—	—	(237)	(237)
Forfeited	(22)	—	(15)	(37)
December 31, 2024	**3,052**	**605**	**2,526**	**6,183**

(1) During the year ended December 31, 2024, 0.2 million restricted share rights were exercised for a cash payment of $0.5 million (year ended December 31, 2023 - nil).

Compensation awards - Recombination Transaction(1)

(number of awards, thousands)	**Deferred Options**	**Deferred Shares**	**Share options**	**Performance share units**	**Restricted share units**	**Total**
December 31, 2023	—	—	—	—	—	—
Acquired(1)	1,192	722	902	532	5	3,353
Exercised for common shares	—	(26)	—	—	(5)	(31)
Exercised for shares held in trust	—	(46)	—	—	—	(46)
Exercised for cash(2)	(3)	(82)	—	—	—	(85)
December 31, 2024	**1,189**	**568**	**902**	**532**	**—**	**3,191**

(1) Recognized as part of the Recombination Transaction which closed on October 31, 2024 (note 4a).
(2) During the year ended December 31, 2024, 0.1 million deferred options and deferred shares were exercised for a cash payment of $0.1 million (year ended December 31, 2023 - nil).

During the year ended December 31, 2024, the Company granted 3.2 million share-based compensation awards, comprised of share options, performance share units and restricted share units under the Company's share-based compensation plans.

a) Deferred options

As a result of the Recombination Transaction, the Company has a deferred option plan which includes 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 during such time and exercise their options. 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 10c).

The Company accounts for the deferred options and performance based long-term incentive awards using the cash-settled method under IFRS 2 and uses the Black-Scholes pricing model to calculate the estimated fair value of the deferred options at the end of each reporting period. The following assumptions were used to arrive at the estimate of fair value:

	December 31, 2024	October 31, 2024[1]
Dividend yield (%)	**—**	—
Forfeiture rate (%)	**5.00**	5.00
Expected volatility (%)	**48.61**	48.08
Risk-free interest rate (%)	**2.89**	3.03
Contractual life (years)	**5.0**	5.0
Weighted average share price at grant date	**$ 0.81**	$ 0.81
Closing share price on December 31, 2024	**$ 2.12**	$ 2.04

(1) Fair value assumptions used in the fair value calculation of the deferred option share-based compensation liability included in the Recombination Transaction (note 4a).

The following table summarizes information about the deferred options and performance-based long-term incentive awards outstanding:

	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 $1.00	914	2.2	0.02	560	0.04
$1.01 to $2.25	132	1.7	1.70	87	1.70
$2.26 to $3.50	9	1.8	3.05	6	3.05
$3.51 to $5.00	16	2.5	4.55	8	4.55
$5.01 to $6.65	118	2.6	5.23	59	5.23
Total	1,189	2.1	0.81	720	0.74

b) Deferred shares

As a result of the Recombination Transaction with Perpetual, the Company has a deferred share plan which includes agreements in place with directors and certain employees. In the case of directors, the deferred shares granted vest upon retirement from the Board of Directors and for employees, the 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 11e), 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 10c).

The Company accounts for the deferred options 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 the Company's closing share price. The closing share price on October 31, 2024 of $2.04 per share was used in the initial fair value calculation in the purchase price allocation (note 4a). The deferred shares were revalued at December 31, 2024 using Rubellite's closing share price of $2.12 per share.

c) Share options

Rubellite’s share option plan provides 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 share option plan 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 vest evenly over four years, commencing on the first anniversary, with expiry occurring five years after issuance. Share options include options that were from the Recombination Transaction with Perpetual. Share options issued previously by Perpetual, acquired as part of the Recombination Transaction, were done under the same terms.

Share options compensation plan

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, 2024:

		December 31, 2024		December 31, 2023[(1)]
Dividend yield (%)		**—**		—
Forfeiture rate (%)		**5.00**		5.00
Expected volatility (%)		**51.68**		64.00
Risk-free interest rate (%)		**2.89**		4.12
Contractual life (years)		**5.0**		5.0
Weighted average share price at grant date	**$**	**2.33**	$	2.09
Closing share price[(2)]	**$**	**2.12**	$	2.01

(1) Share options were accounted for as equity-settled share-based compensation awards at December 31, 2023. The Black-Scholes assumptions used are based on the grant date fair value and were not subsequently re-valued.
(2) The closing share price at December 31, 2023 was not used in the Black-Scholes model under the equity-settled share based compensation as awards were not re-valued after the grant date. The weighted average fair value at grant date of share option awards at December 31, 2023 were $1.11 per share.

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

	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)**
$1.01 to $2.00	716	1.8	1.99	509	2.00
$2.01 to $3.00	2,249	3.5	2.40	677	2.60
$3.01 to $3.65	87	2.5	3.65	43	3.65
Total	3,052	3.0	2.34	1,229	2.39

Share option compensation plan from the Recombination Transaction

The Company uses the Black-Scholes pricing model to calculate the estimated fair value of the share option awards from the Recombination Transaction. The following assumptions were used to arrive at the estimate of fair value as at December 31, 2024:

		December 31, 2024		October 31, 2024[(1)]
Dividend yield (%)		**—**		—
Forfeiture rate (%)		**5.00**		5.00
Expected volatility (%)		**49.79**		49.45
Risk-free interest rate (%)		**2.89**		3.02
Contractual life (years)		**5.0**		5.0
Weighted average share price at grant date	**$**	**2.83**	$	2.83
Closing share price	**$**	**2.12**	$	2.04

(1) Fair value assumptions used in the fair value calculation of the share option share-based compensation liability acquired from Perpetual in the Recombination Transaction which closed on October 31, 2024.

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

	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 $1.00	112	0.3	0.35	112	0.35
$1.01 to $2.25	236	1.5	1.54	177	1.54
$2.26 to $3.50	298	3.8	2.75	75	2.75
$3.51 to $5.00	7	2.2	4.60	4	4.60
$5.01 to $6.65	249	2.6	5.23	124	5.23
Total	902	2.4	2.83	492	2.40

d) Performance share units

The Company has a performance share unit plan for the Company's executive officers. Performance share units granted under the performance share unit plan vest two years after the date upon which the performance units were granted. 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 participants of the performance share unit plan leave the organization other than through retirement or termination without cause prior to the vesting date. Performance share units include awards that were acquired in the Recombination Transaction with Perpetual (note 4a). The terms of performance share units issued previously by Perpetual were done under the same terms.

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 1.9 was applied to performance share units granted in 2022 that vested in the second quarter of 2024. As at December 31, 2024, a performance factor of 2.0 and 1.0 has been assumed for unvested performance share units granted in 2023 and 2024, respectively. A performance factor of 0.5 has been assumed for unvested performance share units granted in 2023 and 2024 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 using the cash-settled method under IFRS 2 and uses an intrinsic pricing model to calculate the estimated fair value of the performance share units 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 closing share price on October 31, 2024 of $2.04 per share was used in the initial fair value calculation in the purchase price allocation (note 4a). The performance share units were revalued at December 31, 2024 using Rubellite's closing share price of $2.12 per share.

e) Restricted share units

The Company has a restricted share unit plan for directors, officers, employees or consultants. The restricted share units 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 of the restricted share units 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, 2024 of $2.12 per share.

12. 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. 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, 2024 is $22.0 million of revenue related to December 2024 sales production (December 31, 2023 - $7.5 million of revenue related to December 2023 sales production). At December 31, 2024, two commodity purchasers accounted for 75 percent of revenue recorded in accounts receivable (December 31, 2023 - one purchaser accounted for 78 percent), related to December 2024 sales production, none of which is considered to be a credit risk as Rubellite enters into sales contracts with established creditworthy counterparties.

		December 31, 2024		December 31, 2023
Oil and natural gas revenue				
Oil	**$**	**164,206**	$	88,968
Natural gas		**2,627**		—
NGL		**1,551**		—
Total oil and natural gas revenue	**$**	**168,384**	$	88,968

13. BANK DEBT

As at December 31, 2024, the Company's first lien credit facility, upon closing of the Recombination Transaction, had a borrowing limit of $140.0 million (December 31, 2023 - $57.0 million). The initial term is to May 31, 2025 and may be extended for a further twelve months to May 31, 2026 subject to lender approval. If not extended by May 31, 2025, all outstanding advances would be repayable on May 31, 2026. The next semi-annual borrowing base redetermination is scheduled on or before May 31, 2025.

On August 2, 2024, the Company's lenders provided a $20.0 million (December 31, 2023 - nil) bank syndicate term loan bearing interest at the lenders prime rate or Canadian Overnight Repo Rate Average ("CORRA") rates, plus applicable margins and standby fees. The bank syndicate term loan was repaid in full in conjunction with the closing of the Recombination Transaction on October 31, 2024.

As at December 31, 2024, $108.5 million was drawn against the credit facility (December 31, 2023 - $29.3 million) and $3.6 million (December 31, 2023 - $0.4 million) of letters of credit have been 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, 2024 was 8.2% per annum. For the year ended December 31, 2024, if interest rates changed by 1% with all other variables held constant, the impact on annual cash finance expense and net income and comprehensive income would be $0.8 million.

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

At December 31, 2024, the credit facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

14. TERM LOAN

	Maturity date	Interest rate	December 31, 2024 Principal	December 31, 2024 Carrying Amount	December 31, 2023 Principal	December 31, 2023 Carrying amount
Term loan	August 2, 2029	11.5%	**$ 20,000**	**$ 19,027**	$ —	$ —

On August 2, 2024, Rubellite entered into a senior secured second-lien Term Loan which was placed, directly or indirectly, with certain directors and officers of Rubellite and the Company's significant shareholder for $20.0 million. 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, 2024, Rubellite paid $1.0 million in cash interest payments to the holders of the Term Loan (year ended December 31, 2023 - nil).

At December 31, 2024, the Term Loan has been recorded at the present value of future cash flows, net of $1.0 million in issue and discount costs which are amortized over the remaining term using a weighted average effective interest rate of 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, 2024, entities controlled or directed by the Company's Chief Executive Officer ("CEO") hold $18.4 million of the outstanding Term Loan.

15. 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, 2024	December 31, 2023
Income before income tax	**$ 59,033**	$ 26,603
Combined federal and provincial tax rate	**23%**	23%
Computed income tax expense	**13,577**	$ 6,119
Increase (decrease) in income taxes resulting from:		
Non-deductible expenses	**763**	700
Non-taxable gain on acquisition	**(7,272)**	—
Flow-through shares - tax pools renounced	**—**	3,048
Other	**(550)**	(377)
Change in unrecognized deferred tax assets	**2,542**	(1,448)
Deferred tax expense	**$ 9,060**	$ 8,042

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

	December 31, 2023	Recognized in earnings	Recognized in equity	Acquisitions	**December 31, 2024**
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**
Total deferred tax assets	$ 15,043	$ (9,060)	$ (369)	$ 15,823	**$ 21,437**

	December 31, 2022	Recognized in earnings	Recognized in equity	December 31, 2023
Assets (liabilities):				
Property, plant and equipment	$ 13,503	$ (9,728)	$ (1,540)	$ 2,235
Decommissioning obligations	859	1,118	—	1,977
Fair value of derivatives	(158)	(1,990)	—	(2,148)
Share purchase warrants	460	(460)	—	—
Share and debt issue costs	(148)	652	58	562
Non-capital losses	10,051	2,366	—	12,417
Total deferred tax assets	$ 24,567	$ (8,042)	$ (1,482)	$ 15,043

The deductible temporary differences included in the Company’s unrecognized deferred tax assets relate to resource tax pools and amount to $48.6 million at December 31, 2024 (December 31, 2023 - $37.5 million).

As at December 31, 2024, the Company had approximately $182.5 million (December 31, 2023 – $53.9 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 $401.6 million (December 31, 2023 – $278.3 million) available for future use as deductions from taxable income, as indicated below:

	December 31, 2024	December 31, 2023
Canadian oil & gas properties	**$ 116,894**	$ 120,430
Canadian development expense	**232,759**	125,696
Canadian exploration expense	**—**	8,157
Undepreciated capital cost	**51,903**	23,983
Total tax pools	**$ 401,556**	$ 278,266

Deferred tax assets have not been recognized in respect of capital losses of $143.8 million (December 31, 2023 - nil) 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.

16. FINANCE EXPENSE

	December 31, 2024	December 31, 2023
Interest on bank debt (note 13)	**$ 5,897**	$ 1,923
Interest on term loan (note 14)	**952**	—
Interest on lease liabilities (note 9)	**55**	—
Total cash finance expense	**6,904**	1,923
Amortization of debt issue costs (note 14)	**63**	—
Accretion on decommissioning obligations (note 8a)	**316**	128
Accretion on other provision (note 8b)	**93**	—
Total non-cash finance expense	**472**	128
Finance expense	**$ 7,376**	$ 2,051

17. SUPPLEMENTAL CASH FLOW INFORMATION

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

	December 31, 2024	December 31, 2023
Accounts receivable	**$ (15,519)**	$ (2,308)
Prepaid expenses and deposits	**(2,319)**	91
Product inventory	**(2,273)**	(66)
Accounts payable and accrued liabilities	**26,519**	5,879
Working capital acquired (note 4a)(1)	**(4,707)**	—
Working capital deficit	**$ 1,701**	$ 3,596
Related to operating activities	**3,093**	1,237
Related to investing activities	**(1,392)**	2,359
Working capital deficit	**$ 1,701**	$ 3,596

(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 (note 4a), respectively (December 31, 2023 - nil) adjusted for cash settlements to December 31, 2024.

18. 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, 2024 was $39.1 million (December 31, 2023 - $20.2 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, 2024 (December 31, 2023 - $0.2 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, 2024	December 31, 2023
Financial oil contracts	**$ 3,332**	$ 7,882
Financial natural gas contracts[1]	**6,625**	—
Financial foreign exchange contracts	**(2,735)**	1,459
Risk management contracts	**$ 7,222**	$ 9,341
Risk management contracts – current asset	**9,783**	8,796
Risk management contracts – non-current asset	**429**	545
Risk management contracts – current liability	**(2,765)**	—
Risk management contracts – non-current liability	**(225)**	—
Risk management contracts	**$ 7,222**	$ 9,341

(1) Financial natural gas contracts for periods after December 31, 2024 included in the Recombination Transaction with Perpetual were initially fair valued at $10.1 million at October 31, 2024 and revalued to $6.6 million at December 31, 2024.

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

	December 31, 2024	December 31, 2023
Unrealized gain (loss) on oil contracts	**$ (4,550)**	$ 6,715
Unrealized loss on natural gas contracts[1]	**(3,508)**	—
Unrealized gain (loss) on foreign exchange contracts	**(4,194)**	1,937
Unrealized gain (loss) on financial derivatives	**$ (12,252)**	$ 8,652
Realized gain (loss) on oil contracts	**397**	(383)
Realized gain on natural gas contracts[2]	**2,338**	—
Realized gain (loss) on foreign exchange contracts	**(153)**	65
Realized gain (loss) on financial derivatives	**$ 2,582**	$ (318)
Change in fair value of derivatives	**$ (9,670)**	$ 8,334

(1) Financial natural gas contracts included in the Recombination Transaction with Perpetual were initially fair valued at $10.1 million at October 31, 2024 and revalued to $6.6 million at December 31, 2024.
(2) Realized gains on natural gas risk management contracts relate to contracts acquired from Perpetual in the Recombination Transaction for the November 1, 2024 to December 31, 2024 time period.

Oil risk management contracts

At December 31, 2024, the Company had in place the following oil commodity risk management contracts:

Commodity	Volumes Sold	Term	Reference/Index	Contract Traded Bought/Sold	Average Price ($/bbl)
Crude Oil	2,400 bbl/d	Jan 2025 - Mar 2025	WTI (US$/bbl)	Swap - sold	$74.41
Crude Oil	2,250 bbl/d	Apr 2025 - Jun 2025	WTI (US$/bbl)	Swap - sold	$72.47
Crude Oil	1,600 bbl/d	Jul 2025 - Sep 2025	WTI (US$/bbl)	Swap - sold	$72.20
Crude Oil	400 bbl/d	Oct 2025 - Dec 2025	WTI (US$/bbl)	Swap - sold	$74.86
Crude Oil	2,300 bbl/d	Jan 2025 - Mar 2025	WTI (CAD$/bbl)	Swap - sold	$99.54
Crude Oil	1,900 bbl/d	Apr 2025 - Jun 2025	WTI (CAD$/bbl)	Swap - sold	$99.16
Crude Oil	1,400 bbl/d	Jul 2025 - Sep 2025	WTI (CAD$/bbl)	Swap - sold	$98.89
Crude Oil	2,400 bbl/d	Jan 2025 - Mar 2025	WCS Differential (US$/bbl)	Swap - sold	($14.65)
Crude Oil	2,650 bbl/d	Apr 2025 - Jun 2025	WCS Differential (US$/bbl)	Swap - sold	($14.20)
Crude Oil	2,400 bbl/d	Jul 2025 - Sep 2025	WCS Differential (US$/bbl)	Swap - sold	($14.29)
Crude Oil	1,900 bbl/d	Oct 2025 - Dec 2025	WCS Differential (US$/bbl)	Swap - sold	($14.71)
Crude Oil	2,300 bbl/d	Jan 2025 - Mar 2025	WCS Differential (CAD$/bbl)	Swap - sold	($20.63)
Crude Oil	1,900 bbl/d	Apr 2025 - Jun 2025	WCS Differential (CAD$/bbl)	Swap - sold	($18.72)
Crude Oil	1,400 bbl/d	Jul 2025 - Sep 2025	WCS Differential (CAD$/bbl)	Swap - sold	($18.29)
Crude Oil	600 bbl/d	Jan 2025 - Mar 2025	WCS (CAD$/bbl)	Swap - sold	$79.69
Crude Oil	850 bbl/d	Apr 2025 - Jun 2025	WCS (CAD$/bbl)	Swap - sold	$80.19
Crude Oil	700 bbl/d	Jul 2025 - Sep 2025	WCS (CAD$/bbl)	Swap - sold	$80.00
Crude Oil	200 bbl/d	Oct 2025 - Dec 2025	WCS (CAD$/bbl)	Swap - sold	$80.00

As at December 31, 2024, 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 year would change by $2.2 million due to changes in the fair value of risk management contracts.

Subsequent to December 31, 2024, the Company entered into the following oil commodity risk management contracts:

Commodity	Volumes Sold	Term	Reference/Index	Contract Traded Bought/Sold	Average Price ($/bbl)
Crude Oil	300 bbl/d	Jul 2025 - Sep 2025	WCS (CAD$/bbl)	Swap - sold	$81.60
Crude Oil	400 bbl/d	Apr 2025 - Jun 2025	WTI (US$/bbl)	Swap - sold	$70.90
Crude Oil	200 bbl/d	Jul 2025 - Sep 2025	WTI (US$/bbl)	Swap - sold	$70.26
Crude Oil	300 bbl/d	Jul 2025 - Sep 2025	WTI (CAD$/bbl)	Swap - sold	$100.20
Crude Oil	200 bbl/d	Jul 2025 - Sep 2025	WCS Differential (US$/bbl)	Swap - sold	($12.70)
Crude Oil	400 bbl/d	Jul 2025 - Sep 2025	WCS Differential (US$/bbl)	Swap - sold	($12.75)
Crude Oil	100 bbl/d	Jul 2025 - Sep 2025	WCS Differential (US$/bbl)	Swap - sold	($12.25)
Crude Oil	300 bbl/d	Jul 2025 - Sep 2025	WCS Differential (CAD$/bbl)	Swap - sold	($18.75)

Natural gas risk management contracts

At December 31, 2024, 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 ($/GJ)
Natural gas	5,000 GJ/d	Jan 2025 - Mar 2025	AECO 5A (CAD$/GJ)	Swap - sold	$7.31
Natural gas	10,000 GJ/d	Apr 2025 - Oct 2025	AECO 5A (CAD$/GJ)	Swap - sold	$3.82
Natural gas	10,000 GJ/d	Nov 2025 - Dec 2025	AECO 5A (CAD$/GJ)	Swap - sold	$3.90
Natural gas	5,000 GJ/d	Jan 2026 - Mar 2026	AECO 5A (CAD$/GJ)	Swap - sold	$4.00

As at December 31, 2024, 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 $2.0 million due to changes in the fair value of risk management contracts.

Subsequent to December 31, 2024, the Company entered into the following natural gas commodity risk management contracts:

Commodity	Volumes Sold	Term	Reference/Index	Contract Traded Bought/Sold	Average Price ($/GJ)
Natural gas	5,000 GJ/d	Apr 2025 - Oct 2025	AECO 5A (CAD$/GJ)	Swap - bought	$2.00
Natural gas	2,638 GJ/d	Apr 2025 - Oct 2025	AECO 7A / NYMEX Differential (US$/GJ)	Swap - bought	($2.56)
Natural gas	2,500 GJ/d	Nov 2025 - Mar 2026	AECO 5A (CAD$/GJ)	Swap - bought	$2.98

Foreign exchange risk management contracts

At December 31, 2024, the Company had in place the following CAD/USD foreign exchange risk management contracts:

Contract	Notional amount	Term	Price (CAD$/US$)
Average rate forward (CAD$/US$)	$4,361,000 US$/month	Jan - Mar 2025	1.3628
Average rate forward (CAD$/US$)	$3,700,000 US$/month	Apr - Jun 2025	1.3674
Average rate forward (CAD$/US$)	$3,050,000 US$/month	Jul - Sep 2025	1.3680
Average rate forward (CAD$/US$)	$1,300,000 US$/month	Oct - Dec 2025	1.3785
Average rate forward (CAD$/US$)	$2,500,000 US$/month	Jan - Dec 2026	1.4066

Contract	Notional amount	Term	Floor Price (CAD$/US$)	Ceiling Price (CAD$/US$)	Reset Price (CAD$/US$)
Knock-in Collar (CAD$/US$)	$500,000 US$/month	Jan - Dec 2025	1.3700	1.4375	1.3875
Knock-in Collar (CAD$/US$)	$500,000 US$/month	Jul - Dec 2025	1.3700	1.4300	1.4000
Knock-in Collar (CAD$/US$)	$2,500,000 US$/month	Jan - Dec 2026	1.3900	1.4670	1.4050

As at December 31, 2024, 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 $1.3 million due to changes in the fair value of risk management contracts.

Subsequent to December 31, 2024, the Company entered into the following CAD/USD foreign exchange risk management contracts:

Contract	Notional amount	Term	Price (CAD$/US$)
Average rate forward (CAD$/US$)	$250,000 US$/month	Apr - Jun 2025	1.4500
Average rate forward (CAD$/US$)	$353,000 US$/month	Jul - Sep 2025	1.4130

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, and accounts payable and accrued liabilities approximate their carrying amounts due to their short terms to maturity. They are classified as amortized cost, level 1.

The fair value of risk management contracts are classified as FVTPL, level 2.

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

As of December 31, 2024	Gross	Netting[(1)]	Carrying Amount	Fair value Level 1	Fair value Level 2	Fair value 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.

As of December 31, 2023	Gross	Netting[(1)]	Carrying Amount	Fair value Level 1	Fair value Level 2	Fair value Level 3
Financial assets						
Fair value through profit and loss						
Risk management contracts	$ 9,645	$ (304)	$ 9,341	$ —	$ 9,341	$ —
Financial liabilities						
Financial liabilities at amortized cost						
Bank debt	(29,317)	—	(29,317)	(29,317)	—	—
Fair value through profit and loss						
Risk management contracts	(304)	304	—	—	—	—

(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 policy is 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 its $140.0 million (December 31, 2023 - $57.0 million) first lien credit facility with a syndicate of lenders, under which $30.4 million (December 31, 2023 - $27.3 million) was available at December 31, 2024, comprised of current borrowings of $108.5 million (December 31, 2023 - $29.3 million), letters of credit of $3.6 million (December 31, 2023 - $0.4 million) and cash and cash equivalents of $2.6 million (December 31, 2023 - nil).

19. 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, 2024	December 31, 2023
Short-term compensation	**$ 2,797**	$ 1,056
Share-based payments	**2,194**	1,507
Total	**$ 4,991**	$ 2,563

Prior to Recombination Transaction, short-term compensation for key management personnel was recognized through the MSA (note 20) 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.

20. RELATED PARTIES

Until the Recombination Transaction in the fourth quarter of 2024, Rubellite and Perpetual were considered related parties due to the existence of an MSA. Further, certain officers and directors were key management of and had significant influence over Rubellite while also being key management of and having deemed control over Perpetual. Under the MSA, Rubellite reimbursed Perpetual for certain technical and administrative services provided to Rubellite split on a relative production basis. Effective June 1, 2024, the MSA was amended to split shared costs on a 80% Rubellite and 20% Perpetual basis. During the year ended December 31, 2024, until the closing of the Recombination Transaction, Rubellite was billed by Perpetual for net transactions, which are considered to be normal course of oil and gas operations totaling $12.7 million (year ended December 31, 2023 - $6.9 million). Included within this amount are $5.0 million (year ended December 31, 2023 - $3.4 million) of costs charged to Rubellite through the MSA prior to the closing of the Recombination Transaction.

21. CONTRACTUAL OBLIGATIONS

As at December 31, 2024, the Company's minimum contractual obligations over the next five years and thereafter, excluding estimated interest payments, are as follows:

	2025	2026	2027	2028	Thereafter	Total
Contractual obligations						
Accounts payable and accrued liabilities	$ 60,451	$ —	$ —	$ —	$ —	**$ 60,451**
Term loan (note 14)	—	—	—	—	20,000	**20,000**
Bank debt (note 13)	—	108,500	—	—	—	**108,500**
Pipeline transportation commitment	2,716	2,716	538	538	3,232	**9,740**
Lease payments (note 9)	670	629	564	615	4,465	**6,943**
Other provision (note 8b)	3,750	3,750	3,750	3,750	4,941	**19,941**
Total	**$ 67,587**	**$ 115,595**	**$ 4,852**	**$ 4,903**	**$ 32,638**	**$ 225,575**

The Company has a drilling commitment on certain GORR lands that must be fulfilled by June 30, 2026 (the "Commitment Date"). 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, 2024, the Company has drilled sixteen (16.0 net) of the 59 wells that are required 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

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Bank of Montreal
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Shell Trading Canada

RESERVE EVALUATION CONSULTANTS

McDaniel & Associates Consultants Ltd.

REGISTRAR AND TRANSFER AGENT

Odyssey Trust Company