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 and six months ended June 30, 2025, as well as the information and estimates concerning the Corporation's future outlook based on currently available information. This discussion should be read in conjunction with the Corporation's unaudited condensed consolidated interim financial statements and accompanying notes for the three and six months ended June 30, 2025 *as well as the audited consolidated financial statements and accompanying notes for the year ended December 31, 2024. Disclosure, which is unchanged from the December 31, 2024 MD&A has not been duplicated herein. 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 August 5, 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 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, liquids-rich conventional natural gas assets in the deep basin of West Central Alberta, and undeveloped bitumen leases in Northern Alberta. The Company is pursuing a robust growth plan focused on heavy oil exploration and development utilizing multi-lateral, horizontal drilling technology, targeting superior corporate returns and free funds flow generation while maintaining a conservative capital structure and prioritizing operational excellence. Additional information on the Company can be accessed on the Company's website at www.rubelliteenergy.com or on SEDAR+ at www.sedarplus.ca.

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

Prior Transactions

Recombination Transaction

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

Buffalo Mission Acquisition

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

SECOND QUARTER 2025 OPERATIONAL AND FINANCIAL HIGHLIGHTS

- Rubellite delivered record second quarter conventional heavy oil sales production of 8,637 bbl/d that exceeded the high end of guidance and was up 4% relative to the first quarter of 2025 (Q1 2025 - 8,339 bbl/d) and 92% relative to the second quarter of 2024 (Q2 2024 - 4,503 bbl/d). Second quarter total sales production of 12,425 boe/d (72% heavy oil and NGL) also exceeded the high end of guidance. Production growth quarter over quarter was driven by the successful drilling programs at Figure Lake and Frog Lake which brought eleven (10.0 net) new wells on production during the second quarter of 2025. The Figure Lake gas plant that commenced operations on January 23, 2025, added an average of 3.0 MMcf/d of solution gas sales plus associated liquids (17 boe/d) in the second quarter of 2025.
- Exploration and development capital expenditures(1) totaled $23.8 million for the second quarter of 2025, to drill, complete, equip and tie-in five (5.0 net) multi-lateral horizontal development wells at Figure Lake and six (4.0 net) multi-lateral horizontal development wells at Frog Lake. Included in second quarter development capital spending was $0.7 million for the Figure Lake gas conservation project and the expansion of the gas gathering system.
- Land and other spending totaled $7.3 million in the second quarter of 2025 and included $0.5 million of spending on seismic purchases (Q2 2024 - nominal). An additional $0.1 million (Q2 2024 - nominal) was spent on decommissioning, abandonment and reclamation activities.
- Adjusted funds flow(1) in the second quarter of 2025 was $37.3 million ($0.40 per share), up 81% (21% per share) from the second quarter of 2024 (Q2 2024 - $20.7 million or $0.33 per share).
- Cash costs(1) were $20.7 million or $18.26/boe in the second quarter of 2025, down 19% on a per boe basis from the second quarter of 2024 (Q2 2024 - $9.3 million or $22.58/boe).
- Net income was $16.1 million ($0.17 per share) in the second quarter of 2025 (Q2 2024 - $12.4 million net income and $0.20 per share).
- As at June 30, 2025, net debt(1) was $142.4 million, down 8% with the reduction of $11.7 million from $154.0 million as at December 31, 2024 driven by positive free funds flow(1) of $17.1 million in the first half of 2025 which was used to reduce net debt and other balance sheet obligations.
- Rubellite had available liquidity(2) at June 30, 2025 of $32.4 million, comprised of the $140.0 million borrowing limit of Rubellite's first lien credit facility, less current bank borrowings of $106.2 million and outstanding letters of credit of $1.4 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

Greater Figure Lake (Figure Lake and Edwand)

Heavy oil sales production from the Greater Figure Lake area averaged 5,544 bbl/d for the second quarter as compared to 5,326 bbl/d for the first quarter of 2025, an increase of 4%. Solution gas sales contributed 3.0 MMcf/d plus associated natural gas liquids of 17 boe/d which brought total sales production at Figure Lake for the second quarter to 6,064 boe/d (92% oil and liquids). Rubellite is currently expanding the Figure Lake 1-13 Gas Plant to manage additional associated solution gas volumes and increase total throughput capacity to approximately 5.9 to 6.4 MMcf/d. Completion of the expansion is expected in August 2025.

During the second quarter of 2025, Rubellite drilled and rig released three (3.0 net) development horizontal wells in the Greater Figure Lake area, all targeting the Wabiskaw Member of the Clearwater Formation, with 33 meter inter-leg spacing and typical 15,000m open hole length per the Figure Lake well design adopted in the latter half of 2024. Results from the 2025 development capital program to date across the Greater Figure Lake field have achieved an average(1) IP30 of 271 bbl/d (7 wells) and IP60 of 267 bbl/d (5 wells), as compared to the McDaniel Tier 1 Type Curve(2) rates for 33 meter inter-leg spacing of 177 bbl/d (IP30) and 169 bbl/d(2) (IP60).

In addition to development drilling, two (2.0 net) step-out delineation wells were drilled in the Greater Figure Lake area with 50m inter-leg spacing and ~10,000m open hole length, to test and confirm productivity from two new pools in the Wabiskaw Member. The first well, 00/01-14-062-18W4 ("1-14 Well"), encountered the down dip limit of the first pool, yielding lower oil saturations and higher water cuts than averaged elsewhere in the field. The second well, 00/04-32-060-17W4 ("4-32 Well") has fully recovered load oil, and with early Initial Production (IP15) of 58 bbl/d is within the range of expected outcomes supporting further development of the pool in accordance with the geological model established for the field.

Rubellite is actively advancing several opportunities to increase the economic recovery factor for heavy oil at Figure Lake beyond the average anticipated primary recovery factor of approximately 4.0 to 5.5 percent of the original oil in place.

A waterflood pilot is currently planned for the fourth quarter of 2025 from a surface location at 9-35-63-18W4 (the "9-35 Pad"). The waterflood pilot pattern will consist of a single horizontal multi-lat well with two sets of four legs each (8 legs in total), with ~150 meters between the four-leg sets. Each 4-leg set will be drilled with 33 meter inter-leg spacing, and the waterflood producer well will have a planned total open hole length for the 8 legs of approximately 10,000 meters. A separate single leg water injection well will be drilled along the center line between the two 4-leg sets, and water injection is expected to commence in early 2026.

The Company is also advancing a novel natural gas-based re-injection pilot at Figure Lake for enhanced oil recovery, with an experimental well now configured at the 01-13-063-18W4 pad (the "1-13 Pad"), on the same site as the Figure Lake 1-13 Gas Plant. Results from the waterflood pilot and gas re-injection experiment will inform future development patterns and enhanced oil recovery techniques to be implemented across the Greater Figure Lake area.

Rubellite will also test larger diameter (200mm) boreholes at the 9-35 Pad in the third quarter of 2025 to determine if incremental economic returns associated with improved inflow and productivity can be realized relative to the robust economics established for the existing 159mm boreholes drilled to date at Figure Lake.

3D seismic acquired in the first quarter of 2025, imaging the northern end of Figure Lake, has now been interpreted and a Sparky exploration well is planned to be drilled in the first quarter of 2026. Separate detailed mapping work has identified an Upper Clearwater prospect in the southern part of the greater Figure Lake area. If associated exploration wells are successful, there are approximately 15.0 net follow-up Sparky locations and up to 10.0 net follow-up Upper Clearwater locations, all of which would be incremental to the existing Clearwater development inventory and secondary targets inventory at Figure Lake.

Consistent production results continue to support the geologic model at Figure Lake and affirm the 243.0 net development drilling inventory locations(3) in the Wabiskaw, including 96.2 net proven and probable undeveloped(2)(3) booked locations. Under a one-rig program, which would provide for the drilling of 18 wells per year at Figure Lake, the Clearwater location count at Figure Lake represents over 13 years of low-risk development drilling inventory.

Frog Lake

Production at the Frog Lake property grew 5% to average 2,539 bbl/d (100% heavy oil) for the second quarter, as compared to 2,423 bbl/d (100% heavy oil) for the first quarter of 2025.

Results from the 2025 capital drilling program to date at Frog Lake (all wells drilled using an oil-based mud ("OBM") drilling system and targeting the north Waseca sand) achieved an average(1) IP30 and IP60 of 140 bbl/d (9 wells) and 128 bbl/d (7 wells) respectively, as compared to the McDaniel Waseca North Type Curve(2) IP30 and IP60 of 107 bbl/d and 104 bbl/d established by McDaniel at year-end 2024 using historical data obtained from wells drilled with water-based mud systems.

Rubellite switched its drilling operations at Frog Lake in December 2024 to utilize OBM. The OBM trial at Frog Lake has confirmed the benefits of using OBM fluid consistent with Rubellite's operations at Figure Lake, where the use of OBM has improved hole cleaning and stability, accelerated the time to stabilized reservoir production, and reduced drill pipe wear, water handling and disposal costs as compared to conventional water-based mud systems. The Company is continuing to utilize OBM in its ongoing drilling operations at Frog Lake as it evaluates the effects on long term production performance in different parts of the Waseca reservoir across the Frog Lake field.

In addition to continued drilling of the Waseca sand as the primary development zone at Frog Lake, the Company is planning two exploration wells in the third quarter of 2025, targeting the General Petroleum ("GP") sand. The first well will be drilled using a single leg lined horizontal lateral design and the second well will be drilled using an alternative lined "fish bone" well design. Learnings from these two wells will confirm type curve assumptions, and inform mapping parameters, appropriate geological cutoffs, and the future well design for optimum economic development of both the GP and Sparky sands in the Mannville Stack at Frog Lake.

Marten Hills

The Company commenced a "bottoms up" waterflood at Marten Hills during the second quarter of 2025, with water injection initiated at its first injection well in April. Value is expected to be realized through reduced water handling costs, reduced production declines and enhanced reserve recoveries.

East Edson

Non-operated drilling planned at East Edson for late in the second quarter was delayed due to wet weather, shifting $3.0 million of capital from Q2 to Q3. Subsequent to the end of the second quarter, the first of four gross (2.0 net) wells was spud in early July, and drilling of the second well is now underway.

A turnaround lasting 5.5 days was completed in June 2025 at the Company's primary gas processing facility at East Edson, reducing average sales by 77 boe/d during the second quarter.

Other Exploration

In addition to exploration activities in the General Petroleum and Sparky zones at Frog Lake and the Sparky prospect at Figure Lake, the Company is continuing to advance multiple additional new venture exploration prospects, pursuing both land capture and play concept de-risking activities while minimizing its risked capital exposure. A total of $3.4 million was invested in the second quarter of 2025 to acquire mineral rights and seismic for exploratory prospects that are expected to be evaluated in 2026.

(1) No development wells were excluded from the calculation of average results except by the criteria for producing days.
(2) Type curve assumptions for the 33 meter 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.
(3) Assuming a January 1, 2025, reference date, of the 243.0 net locations described in the greater Figure Lake area, 65.6 net locations are recognized in the McDaniel Report as proved undeveloped and an additional 30.6 net locations are classified as probable undeveloped. The Company recognizes a total of 316.2 net heavy oil development locations, 93.1 of which are net proved and 45.6 are net probable and included in the McDaniel Reserve Report.

OUTLOOK AND GUIDANCE

For the second half of 2025, Rubellite has budgeted to spend a total of $54.0 to $64.0 million on its exploration and development drilling program, excluding expenditures on land and abandonment and reclamation activities, bringing the total for the year to a range of $100 to $110 million which compares to previous guidance of $95 to $110 million.

The increase in the low end of the guidance range reflects the following drilling program changes:

At Figure Lake:
- One (1.0 net) Clearwater waterflood injection well is now planned;
- Offset somewhat by lower per well costs forecast on the eleven (11.0 net) wells scheduled for H2/25.

At Frog Lake:
- Four Waseca wells are now forecast to be at 100% working interest as Frog Lake Energy Resources Corp. ("FLERC") has elected to be in a gross overriding royalty position on these wells;
- A second 100% working interest exploratory GP well is now planned;
- Offset by one (0.5 net) fewer Waseca development well now planned for H2/25.

Planned capital activity in the second half of 2025 includes:

At Figure Lake:
- Drilling ten (10.0 net) multi-lateral development wells;
- Drilling and equipping one (1.0 net) waterflood injection well;
- Spending to cut a core and conduct several lab experiments to progress enhanced oil recovery technology ideas; and
- Capital to expand the Figure Lake gas conservation project, including additional plant optimization and pipeline tie-ins.

At Frog Lake:
- Drilling eleven (7.0 net) Waseca multi-lateral development wells; and
- Drilling one single leg lined lateral well and one lined fish bone well (1.5 net wells) to evaluate the exploratory General Petroleum zone in the Mannville Stack.

At East Edson, participation in the drilling of four (2.0 net) Wilrich development wells.

Additional spending is planned to continue to advance the evaluation of several heavy oil exploration prospects, to increase gas conservation and usage at Ukalta, and to advance enhanced oil recovery in other areas.

With the ongoing volatility in oil prices, the Company is currently planning to maintain its one rig drilling program at each of Figure Lake and Frog Lake for the second half of 2025. The Company will continue to strive for meaningful per well capital cost reductions to maintain attractive rates of return and payout periods, and will manage its capital spending to prioritize free funds flow generation over production growth in this current weaker oil price environment.

Heavy oil sales volumes based on the current budget are expected to grow 44% to 48% year-over-year to average between 8,200 - 8,400 bbl/d in 2025, unchanged from previous guidance. 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, unchanged from previous guidance.

Capital spending activity will be funded from adjusted funds flow[(1)], with excess free funds flow[(1)] applied to reduce net debt[(1)] and other balance sheet obligations. Aided by Rubellite's extensive commodity price risk management positions, the Company continues to forecast strong adjusted funds flow and free funds flow through the third quarter of 2025 based on the forward market for commodity prices as at August 5, 2025.

Rubellite's Clearwater production continues to realize an attractive offset to WCS benchmark pricing, resulting in an improvement in our heavy oil wellhead differential guidance to a range of $4.00 to $4.50 per barrel vs $5.00 to $5.50 per barrel previously. Additionally, initiatives to improve field operating costs have improved our operating cost guidance to a range of $6.50 to $7.25 per boe versus $7.00 to $7.75 per boe previously.

Rubellite will continue to address end of life ARO, with total abandonment and reclamation expenditures of approximately $0.8 million planned for the second half of 2025. In combination with the $0.9 million of asset retirement obligation spending in the first half of the year, the Company is on track to exceed its area-based mandatory spending requirement for 2025 of $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 2025 is summarized in the table below:

	H1 2025		H2 2025		Full year 2025	
	Capital Expenditures (millions)	**# of wells (*gross/net*)**	**Capital Expenditures (millions)**	**# of wells (*gross/net*)**	**Capital Expenditures (millions)**	**# of wells (*gross/net*)**
Figure Lake[1]		9 / 9.0		11 / 11.0		20 / 20.0
Frog Lake[2]		12 / 8.5		13 / 8.5		25 / 17.0
Marten Hills		1 / 0.3		- / -		1 / 0.3
East Edson		- / -		4 / 2.0		4 / 2.0
Other Exploration		1 / 1.0		1 / 1.0		2 / 2.0
Total[3]	**$46**	**23 / 18.8**	**$54 - $64**	**29 / 22.5**	**$100 - $110**	**52 / 41.3**

(1) Includes one waterflood injection well.
(2) Includes two (1.5 net) wells at Frog Lake targeting secondary exploration zones.
(3) Excludes abandonment and reclamation spending, acquisitions and land expenditures, if any.

Rubellite's capital spending, drilling and operational guidance for 2025 are presented in the table below:

	Previous Full Year 2025 Guidance[1]	Full Year 2025 Guidance
Sales Production (boe/d)	12,200 - 12,400	12,200 - 12,400
Production mix (% liquids)[2]	70%	70%
Heavy Oil Production (bbl/d)	8,200 - 8,400	8,200 - 8,400
Exploration and Development spending ($ millions)[3][4]	$95 - $110	$100 - $110
Heavy oil wellhead differential ($/bbl)[3]	$5.00 - $5.50	$4.00 - $4.50
Royalties (% of revenue)[3]	13% - 14%	13% - 14%
Production and operating costs ($/boe)[3]	$7.00 - $7.75	$6.50 - $7.25
Transportation costs ($/boe)[3]	$5.50 - $6.00	$5.50 - $6.00
General and administrative costs ($/boe)[3]	$3.00 - $3.50	$3.00 - $3.50

(1) Previous full year 2025 guidance dated May 7, 2025.
(2) Liquids means oil, condensate, ethane, propane and butane.
(3) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(4) Excludes land and acquisition spending.

SECOND QUARTER 2025 FINANCIAL AND OPERATING RESULTS

Capital Expenditures

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

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

	Three months ended June 30,					
	2025			2024		
(*$ thousands*)	**E&E**	**PP&E**	**Total**	E&E	PP&E	Total
Drilling and completions	**7**	**19,619**	**19,626**	2,476	14,592	17,068
Facilities	**38**	**4,133**	**4,171**	149	3,847	3,996
Capital expenditures[1]	**45**	**23,752**	**23,797**	2,625	18,439	21,064
Land and other	**3,372**	**3,943**	**7,315**	41	—	41
Corporate	**—**	**56**	**56**	—	2,822	2,822
Capital expenditures, including land and other[1]	**3,417**	**27,751**	**31,168**	2,666	21,261	23,927

(1) Capital expenditures is a non-GAAP measure. See "Non-GAAP and Other Financial Measures".

	Six months ended June 30,					
	2025			2024		
(*$ thousands*)	**E&E**	**PP&E**	**Total**	E&E	PP&E	Total
Drilling and completions	**1,037**	**37,557**	**38,594**	3,770	24,238	28,008
Facilities	**267**	**7,219**	**7,486**	129	5,529	5,658
Capital expenditures[1]	**1,304**	**44,776**	**46,080**	3,899	29,767	33,666
Land and other	**5,046**	**4,777**	**9,823**	136	—	136
Corporate	**—**	**197**	**197**	—	2,917	2,917
Capital expenditures, including land and other[1]	**6,350**	**49,750**	**56,100**	4,035	32,684	36,719

(1) Capital expenditures is a non-GAAP measure. See "Non-GAAP and Other Financial Measures".

Capital expenditures by CGU

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2025**	2024	**2025**	2024
Eastern Heavy Oil	**30,869**	21,105	**55,079**	33,802
West Central	**243**	—	**824**	—
Capital expenditures[1], including land and other	**31,112**	21,105	**55,903**	33,802

(1) Excludes corporate capital expenditures; Non-GAAP measure. See "Non-GAAP and Other Financial Measures".

Wells drilled by area

	Three months ended June 30,		Six months ended June 30,	
(gross/net)	**2025**	2024	**2025**	2024
Development				
Figure Lake[1]	**5 / 5.0**	8 / 8.0	**9 / 9.0**	14 / 14.0
Frog Lake[2][3]	**6 / 4.0**	- / -	**12 / 8.5**	- / -
Marten Hills Waterflood Injection[4]	**-/-**	- / -	**1 / 0.3**	- / -
Exploration				
Other exploratory[5]	**- / -**	- / -	**1.0 / 1.0**	1 / 1.0
Total	**11 / 9.0**	8 / 8.0	**23 / 18.8**	15 / 15.0

(1) One (1.0 net) well drilled on the 7-9 pad at Figure Lake was spud on June 22, 2025 and rig released July 7, 2025 and not included in the Q2 2025 well count.
(2) One (1.0 net) well drilled on the 8-11 pad in Frog Lake was spud on June 23, 2025 and rig released on July 7, 2025 and not included in the Q2 2025 well count. The well is at 100% working interest and Frog Lake Energy Resources Corp. ("FLERC") has elected a gross overriding royalty position on this well.
(3) Five wells drilled in the first half of 2025 were at 100% working interest and FLERC has elected gross overriding royalty positions.
(4) One (0.3 net) injection waterflood well drilled at Marten Hills on the 12-35 pad during Q1 2025.
(5) One (1.0 net) horizontal evaluation well was drilled in Q1 2025 and one (1.0 net) vertical stratigraphic evaluation well was drilled in Q1 2024. The wells were transferred to E&E expense in Q1 2025.

Capital Expenditures

During the second quarter of 2025, Rubellite invested a total of $23.8 million in exploration and development activities, before land and other corporate spending, related primarily to the drilling, completion, equipping and tie-in of five (5.0 net) multi-lateral horizontal wells at Figure Lake and six (4.0 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 (1.0 net) well at Frog Lake was spent during the second quarter with both wells being rig released early in the third quarter of 2025. Facilities spending included $0.7 million of expenditures for gas gathering and pipelines tie-ins related the Figure Lake solution gas conservation project. At the West Central liquids-rich conventional natural gas asset at East Edson, Rubellite spent $0.2 million for lease construction, facility improvements and pipelines to support the 2025 drilling program with its 50% joint venture partner.

During the first six months of 2025, the Company spent $46.1 million on exploration and development activities, before land and other corporate spending, primarily related to the drill, complete, equip and tie-in of nine (9.0 net) multi-lateral horizontal wells at Figure Lake, twelve (8.5 net) wells at Frog Lake, one (0.3 net) waterflood injection well at Marten Hills and one (1.0 net) exploratory evaluation well. Facilities spending at Figure Lake included $1.8 million related to the Figure Lake solution gas conservation project and spending at East Edson, was $0.8 million.

Land and seismic purchases were $7.3 million in the second quarter of 2025, with total land and seismic spending in 2025 of $9.8 million to acquire core area lands prospective for Clearwater development and to capture acreage on multiple exploration prospects.

During the second quarter of 2025, Rubellite spent $0.1 million (Q2 2024 - nominal) on abandonment and reclamation projects, with total asset retirement obligation expenditures of $0.9 million (2024 - $0.1 million) in the first half of 2025. One reclamation certificate was received from the AER in the second quarter of 2025, bringing the total to two in 2025 (2024 - nil).

Production

	Three months ended June 30,		Six months ended June 30,	
	2025	2024	**2025**	2024
Sales volumes				
Heavy oil (bbl/d)	**8,637**	4,503	**8,489**	4,509
Natural gas (Mcf/d)(1)(2)	**20,522**	—	**21,276**	—
NGL (bbl/d)(2)	**368**	—	**370**	—
Total sales volumes (boe/d)	**12,425**	4,503	**12,405**	4,509

(1) Conventional natural gas production at East Edson yielded a heat content of 1.18 GJ/Mcf during the second quarter of 2025 (Q2 2024 - nil) 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 six months ended June 30, 2025 by CGU:

	Three months ended June 30,		Six months ended June 30,	
	2025	2024	**2025**	2024
Sales volumes by CGU				
Eastern Heavy Oil (boe/d)(1)	**9,157**	4,503	**8,918**	4,509
West Central (boe/d)(2)	**3,268**	—	**3,487**	—
Total sales volumes (boe/d)	**12,425**	4,503	**12,405**	4,509

(1) Primarily from the Clearwater and Mannville Stack formations in Eastern Alberta, which includes solution gas sales production at Figure Lake which commenced in Q1 2025 and assets at Frog Lake that were acquired in Q3 2024.
(2) Acquired through the Recombination Transaction with Perpetual in Q4 2024, which includes assets at East Edson that produces liquids-rich conventional natural gas.

Driven by strong well performance from the one-rig drilling programs at both Figure Lake and Frog Lake, second quarter heavy oil sales production and total sales volumes exceeded the high end of Rubellite's second quarter guidance. Sales production for the three and six months ended June 30, 2025 increased by 7,922 boe/d (176%) and 7,896 boe/d (175%) respectively from the comparative periods of 2024. Production growth was driven by the successful Eastern Heavy Oil drilling program and solution gas tie-in, the BMEC Acquisition at Frog Lake in the third quarter of 2024 and the Recombination Transaction with Perpetual in the fourth quarter of 2024.

During the first half of 2025, production and sales volumes progressively increased as new wells were drilled and commenced delivery to sales terminals. During the first quarter, ten (8.0 net) wells from the Eastern Heavy Oil drilling program began contributing to sales, with an additional eleven (10.0 net) wells added during the second quarter. At the end of the second quarter, three (2.0 net) additional wells were recovering OBM drilling fluid and not yet contributing to sales. At Figure Lake, the newly constructed gas plant commenced operations on January 23, 2025 and added 3.0 MMcf/d and 2.5 MMcf/d of solution gas sales on average during the the three and six months ended June 30, 2025. During the three and six months ended June 30, 2025, assets acquired through the Recombination Transaction at East Edson added 3,268 boe/d and 3,487 boe/d of natural gas and NGL sales production and the Frog Lake assets added 2,539 boe/d and 2,481 boe/d of heavy oil sales production respectively.

As a result of the Recombination Transaction as well as solution gas conservation at Figure Lake, the second quarter sales product mix was comprised of 72% conventional heavy crude oil and NGL and 28% conventional natural gas while the first half 2025 sales product mix averaged 71% liquids and 29% conventional natural gas (2024 comparative periods - 100% conventional heavy crude oil).

Revenue

($ thousands, except as noted)	Three months ended June 30, 2025	2024	Six months ended June 30, 2025	2024
Oil and natural gas revenue				
Oil	**55,002**	35,798	**115,063**	65,621
Natural gas	**3,598**	—	**7,888**	—
NGL	**1,942**	—	**4,198**	—
Oil and natural gas revenue	**60,542**	35,798	**127,149**	65,621
Reference prices				
West Texas Intermediate (WTI) (US$/bbl)	**63.74**	80.57	**67.58**	78.77
Foreign Exchange rate (CAD$/US$)	**1.38**	1.37	**1.41**	1.36
WTI (CAD$/bbl)	**87.96**	110.38	**95.29**	107.13
Western Canadian Select (WCS) differential (US$/bbl)	**(10.27)**	(13.61)	**(11.47)**	(16.46)
WCS (CAD$/bbl)	**73.96**	91.63	**79.13**	84.70
AECO 5A Daily Index (CAD$/GJ)	**1.60**	1.12	**1.83**	1.74
AECO 5A Daily Index (CAD$/Mcf)(1)	**1.69**	1.18	**1.93**	1.84
Rubellite average realized prices(2)				
Oil ($/bbl)	**69.98**	87.35	**74.89**	79.97
Natural gas ($/Mcf)	**1.93**	—	**2.05**	—
NGL ($/bbl)	**57.92**	—	**62.72**	—
Average realized price ($/boe)	**53.54**	87.35	**56.63**	79.97

(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 six months ended June 30, 2025 increased by $24.7 million or 69% and $61.5 million or 94% from the comparative periods of 2024, primarily driven by the increase in sales volumes and partially offset by lower oil prices.

Oil revenue for the second quarter of 2025 of $55.0 million represented 91% of total revenue while conventional heavy crude oil production was 70% of total sales volumes. The 54% increase in oil revenue was driven by the 92% increase in heavy crude oil production, partially offset by a 20% decrease in average realized oil prices. Compared to the second quarter of 2024, the WCS average price decreased to $73.96/bbl (Q2 2024 - $91.63/bbl), attributable to the 21% decrease in WTI prices, partially offset by a slight increase in the CAD$/US$ rate to $1.38 (Q2 2024 - $1.37) and a narrowing of the WCS differential to US$10.27/bbl (Q2 2024 - US$13.61/bbl).

During the first half of 2025, oil revenue was $115.1 million and represented 90% of total revenue while conventional heavy crude oil production was 68% of total sales volumes. The 75% increase in oil revenue was driven by the 88% increase in heavy crude oil production, partially offset by a decrease in average realized oil prices. Lower WCS prices were driven by a decrease in WTI oil prices to US$67.58/bbl (2024 - US$78.77/bbl), partially offset by an increase in the CAD$/US$ rate to $1.41 (2024 - $1.36) and the narrowing of the WCS differential to US$11.47/bbl (2024 - US$16.46/bbl).

Rubellite's realized oil price reflects a price offset for quality and optimization of sales delivery points, which averaged $3.70/bbl and $3.94/bbl for the three and six months ended June 30, 2025 as compared to $4.17/bbl and $4.47/bbl in the comparative periods of 2024.

Primarily as a result of the Recombination Transaction, Perpetual's conventional natural gas assets generated natural gas and NGL revenue of $3.0 million and $1.8 million in the second quarter of 2025 and $7.0 million and $4.1 million during the first half of 2025. With the change in the product mix of the Company, total realized prices on a boe basis decreased 39% and 29% from the comparative 2024 periods.

Risk Management Contracts

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

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

($ thousands, except as noted)	Three months ended June 30, 2025	2024	Six months ended June 30, 2025	2024
Unrealized gain (loss) on risk management contracts				
Unrealized gain (loss) on oil contracts(2)	**12,651**	3,588	**7,631**	(10,322)
Unrealized loss on natural gas contracts	**(632)**	—	**(3,219)**	—
Unrealized gain (loss) on risk management contracts	**12,019**	3,588	**4,412**	(10,322)
Realized gain (loss) on risk management contracts				
Realized gain (loss) on oil contracts(2)	**2,945**	(1,786)	**918**	(746)
Realized gain on natural gas contracts	**1,878**	—	**3,717**	—
Realized gain (loss) on risk management contracts	**4,823**	(1,786)	**4,635**	(746)

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

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

	Three months ended June 30,		Six months ended June 30,	
	2025	2024	**2025**	2024
Realized gain (loss) on risk management contracts				
Realized gain (loss) on oil contracts ($/bbl)(2)	**3.75**	(4.36)	**0.60**	(0.91)
Realized gain on natural gas contracts ($/Mcf)	**1.01**	—	**0.97**	—
Realized gain (loss) on risk management contracts ($/boe)	**4.27**	(4.36)	**2.06**	(0.91)
Average realized prices after risk management contracts(1)				
Oil ($/bbl)(2)	**73.73**	82.99	**75.49**	79.06
Natural gas ($/Mcf)	**2.94**	—	**3.02**	—
NGL ($/bbl)	**57.92**	—	**62.72**	—
Average realized price ($/boe)(1)	**57.81**	82.99	**58.69**	79.06

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

The realized gain on risk management contracts totaled $4.8 million or $4.27/boe for the second quarter of 2025, compared to a loss of $1.8 million or $4.36/boe for the second quarter of 2024. For the six month period ending June 30, 2025, the realized gain on risk management contracts totaled $4.6 million or $2.06/boe (2024 - realized loss of $0.7 million or $0.91/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 gain on risk management contracts was $12.0 million for the second quarter of 2025 (Q2 2024 – $3.6 million unrealized gain) and the unrealized gain on risk management contracts was $4.4 million for the six month period ended June 30, 2025 (2024 - $10.3 million unrealized loss). Unrealized gains and losses represent the change in the mark-to-market value of risk management contracts for future periods as forward commodity prices and foreign exchange rates change. Unrealized gains and losses on risk management contracts are excluded from the Company’s calculation of cash flow from operating activities as non-cash items. Risk management contract gains and losses vary depending on commodity prices and the nature and extent of the risk management contracts in place, which in turn, vary with the Company’s assessment of commodity price risk, committed capital spending and other factors.

Royalties

	Three months ended June 30,		Six months ended June 30,	
($ thousands, except as noted)	**2025**	2024	**2025**	2024
Royalty expenses	**7,631**	3,949	**17,080**	7,270
$/boe	**6.75**	9.64	**7.61**	8.86
Royalties *(% of revenue)(1)*	**12.6**	11.1	**13.4**	11.1

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

Total royalties for the three and six months ended June 30, 2025, were $7.6 million and $17.1 million, an increase from the comparative periods of 2024 on higher production, increased revenue and a higher percentage of wells with gross overriding royalties ("GORR"). During the second quarter of 2025, at the West Central CGU assets at East Edson the annual gas cost allowance ("GCA") adjustment was a credit of $1.0 million (2024 - nil). On a per boe basis, royalties decreased as a result of higher sales volumes and the GCA credit, which more than offset the higher percentage of wells drilled on lands with a GORR. Consistent with lower per boe royalty rates, royalties as a percentage of revenue were lower for the same reason and slightly lower than the Company’s second quarter guided range of 13% to 14%.

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 royalties. 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 40% 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)

	Three months ended June 30,		Six months ended June 30,	
($ thousands, except as noted)	**2025**	2024	**2025**	2024
Net operating costs	**7,591**	2,734	**15,387**	5,344
$/boe	**6.71**	6.67	**6.85**	6.51

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

Total net operating costs for the three and six months ended June 30, 2025 increased to $7.6 million and $15.4 million from $2.7 million and $5.3 million in the comparative periods of 2024 as a result of increased production volumes and higher costs in all areas.

On a per boe basis, net operating costs increased by 1% to $6.71/boe in the second quarter of 2025 (Q2 2024 - $6.67/boe), under the Company's guided range of $7.00 to $7.75/boe as a result of reduced Frog Lake emulsion trucking, water disposal and well-servicing costs and lower than expected carbon tax. For the six months ended June 30, 2025, net operating costs on a per boe basis increased 5% to $6.85/boe (2024 - $6.51/boe) which reflects a higher per unit operating cost on the Frog Lake properties as compared to costs related to the Company's Clearwater assets.

Transportation costs

	Three months ended June 30,		Six months ended June 30,	
($ thousands, except as noted)	**2025**	2024	**2025**	2024
Transportation costs	**6,707**	3,142	**12,938**	6,379
$/boe	**5.93**	7.67	**5.76**	7.77

Transportation costs include 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 six months ended June 30, 2025 increased to $6.7 million and $12.9 million, up from $3.1 million and $6.4 million in the comparative periods of 2024 as a result of higher volumes.

On a per boe basis, transportation costs of $5.93/boe were within the guided range of $5.50 to $6.00/boe and were 23% lower than the second quarter of 2024 (Q2 2024 - $7.67/boe) and 26% lower during the first half of 2025 (2024 - $7.77/boe). The decrease is due to lower trucking rates realized for the Company's Clearwater assets 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 and six months ended June 30, 2025 and 2024**:**

	Three months ended June 30, 2025			Three months ended June 30, 2024		
($ thousands)	**Eastern Heavy Oil**	**West Central**	**Total**	Eastern Heavy Oil	West Central	Total
Revenue	**55,753**	**4,789**	**60,542**	35,798	—	35,798
Royalties	**(7,666)**	**35**	**(7,631)**	(3,949)	—	(3,949)
Net operating costs[1]	**(5,638)**	**(1,953)**	**(7,591)**	(2,734)	—	(2,734)
Transportation costs	**(6,167)**	**(540)**	**(6,707)**	(3,142)	—	(3,142)
Operating netback[1]	**36,282**	**2,331**	**38,613**	25,973	—	25,973
Realized gain on risk management contracts	**—**	**—**	**4,823**	—	—	(1,786)
Total operating netback, after risk management contracts[1]	**36,282**	**2,331**	**43,436**	25,973	—	24,187

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

	Six months ended June 30, 2025			Six months ended June 30, 2024		
($ thousands)	**Eastern Heavy Oil**	**West Central**	**Total**	Eastern Heavy Oil	West Central	Total
Revenue	**116,045**	**11,104**	**127,149**	65,621	—	65,621
Royalties	**(15,789)**	**(1,291)**	**(17,080)**	(7,270)	—	(7,270)
Net operating costs[1]	**(11,732)**	**(3,655)**	**(15,387)**	(5,344)	—	(5,344)
Transportation costs	**(11,769)**	**(1,169)**	**(12,938)**	(6,379)	—	(6,379)
Operating netback[1]	**76,755**	**4,989**	**81,744**	46,628	—	46,628
Realized gain on risk management contracts	**—**	**—**	**4,635**		—	(746)
Total operating netback, after risk management contracts[1]	**76,755**	**4,989**	**86,379**	46,628	—	45,882

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

	Three months ended June 30, 2025			Three months ended June 30, 2024		
($/boe)	**Eastern Heavy Oil**	**West Central**	**Total**	Eastern Heavy Oil	West Central	Total
Revenue	**66.90**	**16.10**	**53.54**	87.35	—	87.35
Royalties	**(9.20)**	**0.12**	**(6.75)**	(9.64)	—	(9.64)
Net operating costs[1]	**(6.35)**	**(6.57)**	**(6.71)**	(6.67)	—	(6.67)
Transportation costs	**(7.40)**	**(1.82)**	**(5.93)**	(7.67)	—	(7.67)
Operating netback[1]	**43.95**	**7.83**	**34.15**	63.37	—	63.37
Realized gain on risk management contracts	**—**	**—**	**4.27**	—	—	(4.36)
Total operating netback, after risk management contracts[1]	**43.95**	**7.83**	**38.42**	63.37	—	59.01

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

($/boe)	Six months ended June 30, 2025 **Eastern Heavy Oil**	 **West Central**	 **Total**	Six months ended June 30, 2024 Eastern Heavy Oil	 West Central	 Total
Revenue	**71.89**	**17.59**	**56.63**	79.97	—	79.97
Royalties	**(9.78)**	**(2.05)**	**(7.61)**	(8.86)	—	(8.86)
Net operating costs(1)	**(7.06)**	**(5.79)**	**(6.85)**	(6.51)	—	(6.51)
Transportation costs	**(7.29)**	**(1.85)**	**(5.76)**	(7.77)	—	(7.77)
Operating netback(1)	**47.76**	**7.90**	**36.41**	56.83	—	56.83
Realized gain on risk management contracts	**—**	**—**	**2.06**	—	—	(0.91)
Total operating netback, after risk management contracts(1)	**47.76**	**7.90**	**38.47**	56.83	—	55.92

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

Rubellite's Eastern Heavy Oil operating netback for the three and six months ended June 30, 2025 increased to $36.3 million and $76.8 million (Q2 2024 - $26.0 million; 2024 - $46.6 million) as a result of higher sales volumes which increased revenue and offset lower realized oil prices and higher royalties and costs reflecting higher production. On a per boe basis, the decrease during the second quarter of 2025 relative to the comparable period of 2024 was driven by lower realized oil prices, partially offset by lower royalties and costs. During the first half of 2025, the decrease was driven by lower realized oil prices and higher royalties and net operating costs, partially offset by lower transportation costs.

Rubellite's total operating netback for the three and six months ended June 30, 2025 increased to $38.6 million and $81.7 million from $26.0 million and $46.6 million in the comparative periods of 2024. The decrease on a per boe basis was driven by lower total realized prices as a result of the addition of natural gas to the sales product mix through the Recombination Transaction and to a lesser extent Figure Lake solution gas sales, and lower oil prices and higher net operating costs, partially offset by lower royalties and transportation costs.

For the three and six month ended June 30, 2025, the operating netback after a realized gain on risk management contracts was $38.42/boe and $38.47/boe (Q2 2024 – $59.01/boe; 2024 - $55.92/boe).

General and administrative ("G&A") expenses

(*$ thousands, except as noted*)	Three months ended June 30, **2025**	 2024	Six months ended June 30, **2025**	 2024
G&A expenses – before MSA costs & recoveries	**5,084**	868	**10,727**	1,546
G&A recoveries	**(1,069)**	—	**(2,298)**	—
MSA costs(1)	**—**	1,531	**—**	2,880
Total G&A expenses	**4,015**	2,399	**8,429**	4,426
$/boe	**3.55**	5.85	**3.75**	5.39

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

G&A expenses for the three and six months ended June 30, 2025 increased to $5.1 million and $10.7 million (Q2 2024 – $0.9 million; 2024 - $1.5 million). Prior to the Recombination Transaction, G&A expenses, excluding MSA costs, consisted primarily of legal fees, computer software licenses, insurance, professional fees and public company costs. After the Recombination Transaction was completed, G&A expenses in Rubellite increased to include all G&A costs previously billed through the MSA including people, office and computer costs and recoveries.

For the three and six months ended June 30, 2025, G&A costs on a per boe basis decreased to $3.55/boe and $3.75/boe from $5.85/boe and $5.39/boe in the comparative periods of 2024 due to higher sales volumes and were slightly higher than the Company's guided range of $3.00 to $3.50/boe.

Depletion

(*$ thousands, except as noted*)	Three months ended June 30, **2025**	 2024	Six months ended June 30, **2025**	 2024
Depletion	**23,669**	8,602	**45,326**	17,499
Depreciation	**505**	142	**1,010**	142
Total depletion and depreciation	**24,174**	8,744	**46,336**	17,641
($/boe)				
Depletion	**20.93**	20.99	**20.19**	21.33
Depreciation	**0.45**	0.35	**0.45**	0.17
$/boe	**21.38**	21.34	**20.64**	21.50

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 June 30, 2025, depletion was calculated on a $484.4 million depletable balance (December 31, 2024 – $473.4 million), $412.0 million in future development costs (December 31, 2024 – $436.3 million) and excluded an estimated $8.9 million of salvage value (December 31, 2024 – $8.7 million).

Depletion and depreciation expense for the second quarter of 2025 was $24.2 million or $21.38/boe (Q2 2024 – $8.7 million or $21.34/boe). For the first half of 2025, depletion and depreciation expense was $46.3 million or $20.64/boe (2024 - $17.6 or $21.50/boe). The increase in depletion related to a higher depletable base than the comparable period as a result of the BMEC Acquisition and the Recombination Transaction. On a per boe basis, depletion was slightly lower than the second quarter of 2024. In the first half of 2025, depletion per boe decreased relative to the comparable 2024 period as a result of the Recombination Transaction, as the West Central assets have higher reserves relative to production than Rubellite's Eastern 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 June 30, 2025, 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 June 30, 2025, 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 first half of 2025 there have been no transfers between E&E and PP&E. During the first half of 2024, the Company transferred $3.0 million 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.

Finance expense

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2025**	2024	**2025**	2024
Cash finance expense				
Interest on bank debt	**1,687**	980	**3,498**	2,087
Interest on Term Loan	**573**	—	**1,140**	—
Interest on lease liabilities	**79**	—	**160**	—
Total cash finance expense	**2,339**	980	**4,798**	2,087
$/boe	**2.07**	2.39	**2.14**	2.55
Non-cash finance expense				
Amortization of debt issue costs	**41**	—	**81**	—
Accretion on decommissioning obligations	**264**	69	**529**	133
Accretion on other provision	**114**	—	**253**	—
Total non-cash finance expense	**419**	69	**863**	133
$/boe	**0.37**	0.17	**0.38**	0.16
Finance expense	**2,758**	1,049	**5,661**	2,220

Total cash finance expense for the three and six months ended June 30, 2025 increased to $2.3 million and $4.8 million (Q2 2024 - $1.0 million; 2024 - $2.1 million) as a result of higher outstanding bank debt and the addition of the term loan in the third quarter of 2024. The effective aggregate interest rate on the Company's revolving bank line during the three and six month period ended June 30, 2025 was 6.3% and 6.2% (Q2 2024 - 8.0%; 2024 - 8.9%) and the interest rate on the term loan was 11.5%.

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

For the three and six months ended June 30, 2025, cash finance expense on a per boe basis decreased from the comparative periods of 2024 due to higher sales volumes.

Deferred Income Taxes

($ thousands)	December 31, 2024	Recognized in earnings	Recognized in equity	**June 30, 2025**
Assets (liabilities):				
Property, plant and equipment	(30,903)	(1,036)	—	**(31,939)**
Decommissioning obligations	7,318	(13)	—	**7,305**
Fair value of derivatives	(1,661)	(1,015)	—	**(2,676)**
Other provision and liabilities	4,049	(1,300)	—	**2,749**
Share and debt issue costs	669	(28)	(86)	**555**
Non-capital losses	41,965	(4,307)	—	**37,658**
Total deferred tax assets	21,437	(7,699)	(86)	**13,652**

For the three and six months ended June 30, 2025, the Company recorded a deferred income tax expense of $6.9 million and $7.7 million (Q2 2024 - income tax expense of $2.4 million; 2024 - income tax expense of $1.4 million).

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)	June 30, 2025	December 31, 2024
Revolving bank debt(1)	**106,212**	105,945
Term Loan (principal)	**20,000**	20,000
Adjusted working capital deficit(1)(2)	**16,141**	28,075
Net debt(2)	**142,353**	154,020
Shares outstanding at end of period (*thousands*)	**93,395**	93,044
Market price at end of period (*$/share*)	**1.95**	2.12
Market value of shares(2)	**182,120**	197,253
Enterprise value(2)	**324,473**	351,273
Net debt as a percentage of enterprise value(2)	**44%**	44%
Trailing twelve-months adjusted funds flow(2)	**127,906**	93,777
Net debt to adjusted funds flow ratio(2)	**1.1**	1.6
Q2 annualized adjusted funds flow(2)(3)	**149,244**	143,420
Net debt to Q2 annualized adjusted funds flow ratio(2)(3)	**1.0**	1.1

(1) Revolving bank debt shown net of cash balance of $2.6 million as at December 31, 2024. Adjusted working capital deficit excludes the cash balance of $2.6 million as at December 31, 2024.
(2) Non-GAAP measure or ratio. See "Non-GAAP and Other Financial Measures".
(3) Based on Q2 2025 adjusted funds flow of $37.3 million, net debt to Q2 annualized adjusted funds flow ratio is 1.0 times at June 30, 2025. See "Non-GAAP and Other Financial Measures" for more details.

At June 30, 2025, Rubellite had net debt of $142.4 million, a 8% decrease from $154.0 million at December 31, 2024. Net debt decreased as a result of adjusted funds flow of $73.2 million exceeding capital expenditures including land and other expenditures of $56.1 million, which generated free funds flow $17.1 million. The positive free funds flow for 2025 was primarily used to reduce net debt and other obligations which included the $3.8 million reduction of the other provision, $0.9 million of spending on decommissioning activities and $1.1 million in payments for cash-settled share-based compensation.

Rubellite had available liquidity at June 30, 2025 of $32.4 million, comprised of the $140.0 million Credit Facility Borrowing Limit, less bank borrowings of $106.2 million and outstanding letters of credit of $1.4 million.

Bank debt

During the period ended June 30, 2025, the Company's first lien credit facility had its borrowing limit of $140.0 million reconfirmed by its syndicate of four lenders (December 31, 2024 - $140.0 million) and was extended with an initial term to May 31, 2026. The initial term may be extended for a further twelve months to May 31, 2027 subject to lender approval. If not extended by May 31, 2026, all outstanding advances would be repayable on May 31, 2027. The next semi-annual borrowing base redetermination is scheduled on or before November 30, 2025.

As at June 30, 2025, $106.2 million was drawn against the credit facility (December 31, 2024 - $108.5 million) and $1.4 million (December 31, 2024 - $3.6 million) of letters of credit 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 June 30, 2025 was 6.3% per annum. For the period ended June 30, 2025, if interest rates changed by 1% with all other variables held constant, the impact on cash finance expense and net income and comprehensive income would be $0.8 million.

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

At June 30, 2025, the credit facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Term Loan

			June 30, 2025		December 31, 2024	
($ thousands)	**Maturity date**	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term loan	August 2, 2029	11.5%	**20,000**	**19,085**	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, and their affiliates, 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 six months ending June 30, 2025, Rubellite paid $0.6 and $1.1 million in cash interest payments to the holders of the term loan (three and six months ended June 30, 2024 - nil).

At June 30, 2025, the term loan has been recorded at the present value of future cash flows, net of $0.9 million (December 31, 2024 - $0.1 million) in issue and discount costs which are amortized over the remaining term using a weighted average effective interest rate of 13.0%.

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

At June 30, 2025, entities controlled or directed by the Company's Chief Executive Officer ("CEO") hold $18.4 million of the outstanding term loan.

Equity

At June 30, 2025, there were 93.3 million common shares outstanding, net of 0.1 million shares held in trust for employee compensation programs.

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

On October 31, 2024, in conjunction with the closing of the Recombination Transaction, Rubellite issued 25.4 million common shares which were valued at $51.7 million using the Company's share price on the closing date of the transaction of $2.04 per share.

At August 5, 2025 there were 93.3 million common shares outstanding, net of 0.1 million shares held in trust for employee compensation programs.

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

(thousands)	**August 5, 2025**
Restricted share units	2,460
Share options	3,052
Performance share units	1,854
Perpetual awards(1)(2)	2,575
Total	**9,941**

(1) Perpetual awards from the Recombination Transaction include 1.0 million deferred options, 0.5 million deferred shares, 0.8 million share options and 0.3 million performance share rights. All Perpetual awards from the Recombination Transaction were adjusted both in number issued and exercise price by the exchange ratio of 5:1.
(2) Perpetual awards include 1.9 million of legacy awards that are settled outside of treasury.

Commodity price risk management

As at August 5, 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 ($/bbl)**
Crude Oil	2,383 bbl/d	Jul 2025 - Sep 2025	WTI (US$/bbl)	Swap - sold	$71.19
Crude Oil	1,900 bbl/d	Oct 2025 - Dec 2025	WTI (US$/bbl)	Swap - sold	$67.15
Crude Oil	1,500 bbl/d	Jan 2026 - Mar 2026	WTI (US$/bbl)	Swap - sold	$65.13
Crude Oil	500 bbl/d	Apr 2026 - Dec 2026	WTI (US$/bbl)	Swap - sold	$65.00
Crude Oil	1,700 bbl/d	Jul 2025 - Sep 2025	WTI (CAD$/bbl)	Swap - sold	$99.12
Crude Oil	3,200 bbl/d	Jul 2025 - Sep 2025	WCS Differential (US$/bbl)	Swap - sold	($13.86)
Crude Oil	1,900 bbl/d	Oct 2025 - Dec 2025	WCS Differential (US$/bbl)	Swap - sold	($14.71)
Crude Oil	1,700 bbl/d	Jul 2025 - Sep 2025	WCS Differential (CAD$/bbl)	Swap - sold	($18.37)
Crude Oil	1,000 bbl/d	Jul 2025 - Sep 2025	WCS (CAD$/bbl)	Swap - sold	$80.48
Crude Oil	200 bbl/d	Oct 2025 - Dec 2025	WCS (CAD$/bbl)	Swap - sold	$80.00

As at August 5, 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 ($/GJ)**
Natural gas	5,000 GJ/d	Jul 2025	AECO 5A (CAD$/GJ)	Swap - sold	$5.65
Natural gas	2,500 GJ/d	Aug 2025 - Oct 2025	AECO 5A (CAD$/GJ)	Swap - sold	$9.01

Foreign exchange risk management

As at August 5, 2025, Rubellite entered into the following foreign exchange risk management contracts:

Fixed Contract	**Notional amount**	**Term**	**Price (CAD$/US$)**
Average rate forward (CAD$/US$)	$3,403,000 US$/month	Jul - Sep 2025	1.3727
Average rate forward (CAD$/US$)	$2,050,000 US$/month	Oct - Dec 2025	1.3763
Average rate forward (CAD$/US$)	$7,500,000 US$/month	Jan - Dec 2026	1.3949

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	Jul - 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

(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 June 30, 2025, the Company has drilled nineteen (19.0 net) of the 59 wells that are required to meet the drilling commitment. Subsequent to June 30, 2025, the Company has drilled another two (2.0 net) wells for a total of twenty one (21.0 net) wells required to meet the drilling commitment.

PROVISIONS

Decommissioning obligations

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

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

($ thousands)	**June 30, 2025**	December 31, 2024
Decommissioning obligations – current	**1,415**	2,000
Decommissioning obligations – non-current	**30,347**	29,817
Total decommissioning obligations	**31,762**	31,817

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

(*$ thousands, except as noted*)	**June 30, 2025**	December 31, 2024
Undiscounted obligations	**42,751**	42,085
Average risk-free rate	**3.6%**	3.3%
Inflation rate	**1.9%**	1.8%
Expected timing of settling obligations	**1 to 25 years**	1 to 25 years

Other provision

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

($ thousands)	**June 30, 2025**	December 31, 2024
Other provisions – current	**3,750**	3,750
Other provisions – non-current	**11,327**	14,824
Total other provisions	**15,077**	18,574

The following assumptions were used to estimate the other provision:

(*$ thousands, except as noted*)	**June 30, 2025**	December 31, 2024
Undiscounted obligations	**16,191**	19,941
Average risk-free rate	**3.0%**	3.0%
Expected timing of settling obligations	**4.7 years**	5.3 years

OFF BALANCE SHEET ARRANGEMENTS

Rubellite has no material off balance sheet arrangements.

NON-GAAP AND OTHER FINANCIAL MEASURES

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

Non-GAAP Financial Measures

Capital Expenditures: Rubellite uses capital expenditures related to exploration and development to measure its capital investments compared to the Company's annual capital budgeted expenditures. Rubellite's capital budget excludes acquisition and disposition activities.

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 June 30,		Six months ended June 30,	
($ thousands)	**2025**	2024	**2025**	2024
Net cash flows used in investing activities	**(38,630)**	(13,094)	**(63,013)**	(37,353)
Change in non-cash working capital	**(7,462)**	10,833	**(6,913)**	(634)
Capital expenditures, including land, corporate and other	**(31,168)**	(23,927)	**(56,100)**	(36,719)
Property, plant and equipment additions	**(27,695)**	(18,439)	**(49,553)**	(29,767)
Exploration and evaluation additions	**(3,417)**	(2,666)	**(6,350)**	(4,035)
Corporate additions	**(56)**	(2,822)	**(197)**	(2,917)
Capital expenditures, including land, corporate and other	**(31,168)**	(23,927)	**(56,100)**	(36,719)

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 June 30,	
(*$ thousands, except per boe amounts*)	***$/boe***	**2025**	*$/boe*	2024
Net operating costs	**6.71**	**7,591**	6.67	2,734
Transportation	**5.93**	**6,707**	7.67	3,142
General and administrative	**3.55**	**4,015**	5.85	2,399
Cash finance expense	**2.07**	**2,339**	2.39	980
Cash costs	**18.26**	**20,652**	22.58	9,255

			Six Months Ended June 30,	
(*$ thousands, except per boe amounts*)	***$/boe***	**2025**	*$/boe*	2024
Net operating costs	**6.85**	**15,387**	6.51	5,344
Transportation	**5.76**	**12,938**	7.77	6,379
General and administrative	**3.75**	**8,429**	5.39	4,426
Cash finance expense	**2.14**	**4,798**	2.55	2,087
Cash costs	**18.50**	**41,552**	22.22	18,236

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 June 30,		Six months ended June 30,	
(*$ thousands, except per boe amounts*)	**2025**	2024	**2025**	2024
Other income	**403**	—	**505**	—
Less: Non processing income	**(343)**	—	**(343)**	—
Processing income	**60**	**—**	**162**	**—**
Production and operating	**7,651**	2,734	**15,549**	5,344
Less: processing income	**(60)**	**—**	**(162)**	**—**
Net operating costs	**7,591**	2,734	**15,387**	5,344
$/boe	**6.71**	6.67	**6.85**	6.51

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

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

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

(*$ thousands*)	**As of June 30, 2025**	As of December 31, 2024
Current assets	**43,605**	44,714
Current liabilities	**(60,071)**	(74,680)
Working capital deficit	**16,466**	29,966
Risk management contracts – current asset	**10,250**	9,783
Risk management contracts – current liability	**(327)**	(2,765)
Right of use liability - current liability	**(380)**	(357)
Share-based compensation liability - current liability	**(4,703)**	(5,357)
Decommissioning obligations – current liability	**(1,415)**	(2,000)
Other provision - current liability	**(3,750)**	(3,750)
Adjusted working capital deficit(1)	**16,141**	25,520
Bank indebtedness	**106,212**	108,500
Term loan (principal)	**20,000**	20,000
Net debt(2)	**142,353**	154,020

(1) Calculation of current assets less current liabilities has been adjusted for the removal of the current portion of risk management contracts, decommissioning liabilities, lease liabilities, share-based compensation and other provisions.
(2) Excludes 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, other provisions 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 and are managed as expenditures through the corporate budgeting process which considers available adjusted funds flow. Management uses adjusted funds flow and adjusted funds flow per boe as key measures to assess the ability of the Company to generate the funds necessary to finance capital expenditures, expenditures on decommissioning obligations, expenditures on share based compensation and meet its financial obligations.

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

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

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands, except as noted*)	**2025**	2024	**2025**	2024
Net cash flows from operating activities	**35,808**	19,916	**62,943**	36,413
Change in non-cash working capital	**495**	721	**4,575**	2,555
Cash-settled share-based compensation	**889**	—	**1,085**	—
Other provision settled	**—**	—	**3,750**	**—**
Decommissioning obligations settled	**119**	27	**892**	148
Adjusted funds flow	**37,311**	20,664	**73,245**	39,116
Adjusted funds flow per share - basic	**0.40**	0.33	**0.79**	0.63
Adjusted funds flow per share - diluted	**0.39**	0.33	**0.77**	0.62
Adjusted funds flow per boe	**33.00**	50.42	**32.62**	47.67

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

The following table shows the calculation of the removal of capital expenditures from adjusted funds flows pre transaction costs:

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands*)	**2025**	2024	**2025**	2024
Adjusted funds flow	**37,311**	20,664	**73,245**	39,116
Capital expenditures, including land, corporate and other	**(31,168)**	(23,927)	**(56,100)**	(36,719)
Free funds flow	**6,143**	(3,263)	**17,145**	2,397

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.

INTERNAL CONTROLS AND PROCEDURES

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

There were no changes in the Company's DC&P or ICFR during the period beginning April 1, 2025 and ending on June 30, 2025 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR. It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

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; the timing for the completion of certain facilities; Rubellite's business plan; and including the forward-looking information contained under the heading "Outlook and Guidance" and "Nature of Business".

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

Undue reliance should not be placed on forward-looking information, which is not a guarantee of performance and is subject to a number of risks or uncertainties, including without limitation those described herein and under "Risk Factors" in the Company's Annual Information Form and MD&A for the year ended December 31, 2024 and 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
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
GJ	gigajoule

Industry Metrics:

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

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:

Assuming a January 1, 2025 reference date, of the 316.2 net heavy oil drilling development locations disclosed in this MD&A, 93.1 net are proved and 45.6 net are probable undeveloped locations in the McDaniel year-end 2024 reserve report. There are 9.5 net proven natural gas locations and 4.4 net probable natural gas locations in the McDaniel year-end 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

SUMMARY OF QUARTERLY RESULTS

($ thousands, except as noted)	Q2 2025	Q1 2025	Q4 2024	Q3 2024
Financial				
Oil and natural gas revenue	**60,542**	66,607	59,081	43,682
Net income (loss) and comprehensive income (loss)	**16,051**	1,160	26,747	15,010
Per share – basic(2)	**0.17**	0.01	0.31	0.23
Per share – diluted(2)	**0.17**	0.01	0.30	0.23
Total assets	**561,545**	551,889	562,612	432,836
Cash flow from operating activities	**35,808**	27,135	39,402	19,973
Adjusted funds flow, after transaction costs(1)(6)	**37,311**	35,934	31,632	23,029
Per share – basic(1)(2)	**0.40**	0.39	0.36	0.35
Per share – diluted(1)(2)	**0.39**	0.38	0.36	0.35
Capital expenditures, including land and other(1)	**31,168**	24,932	35,537	36,650
Acquisitions(3)	**—**	—	68,467	62,732
Common shares (thousands)				
Weighted average – basic	**93,279**	92,930	87,655	65,834
Weighted average – diluted	**95,074**	95,068	88,546	66,571
Operating				
Heavy oil (bbl/d)(4)	**8,637**	8,339	7,754	5,954
Natural gas (Mcf/d)	**20,522**	22,038	14,140	—
NGL (bbl/d)(5)	**368**	371	275	—
Daily average sales production (boe/d)	**12,425**	12,383	10,386	5,954
Rubellite average realized oil price(1)(7)				
Oil ($/bbl)	**69.98**	80.03	76.97	79.75
Natural gas ($/Mcf)	**1.93**	2.16	2.01	—
NGL ($/bbl)	**57.92**	67.54	61.32	—
Total average realized price ($/boe)	**53.54**	59.77	61.83	79.75

($ thousands, except as noted)	Q2 2024	Q1 2024	Q4 2023	Q3 2023
Financial				
Oil revenue	35,798	29,823	27,224	25,777
Net income and comprehensive income	12,368	(4,153)	9,523	3,942
Per share – basic(2)	0.20	(0.07)	0.15	0.06
Per share – diluted(2)	0.19	(0.07)	0.15	0.06
Total assets	281,549	267,298	271,153	223,353
Cash flow from (used in) operating activities	19,916	16,497	18,963	14,957
Adjusted funds flow, after transaction costs(1)(6)	20,664	18,452	16,923	15,554
Per share – basic(1)(2)	0.33	0.30	0.27	0.25
Per share – diluted(1)(2)	0.33	0.30	0.27	0.25
Capital expenditures, including land and other(1)	23,927	12,792	26,320	11,330
Acquisitions(3)	—	—	33,173	—
Dispositions(3)	—	—	(7,900)	—
Common shares (thousands)				
Weighted average – basic	62,494	62,457	62,440	61,956
Weighted average – diluted	63,446	62,457	62,958	62,597
Operating				
Daily average oil sales production (boe/d)	4,503	4,514	4,209	3,154
Rubellite average realized oil price(1)(7)				
Average realized oil price ($/bbl)	87.35	72.60	70.31	88.85

(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 $25.8 million and $66.6 million over the prior eight quarters largely due to increasing sales volumes from 3,154 boe/d to 12,425 boe/d, partially offset by volatility in commodity pricing. Net income (loss) has ranged between a loss of $4.2 million and income of $26.7 million primarily due to increased production, corporate acquisitions, volatility of commodity prices and its impact on revenue, royalties and realized and unrealized risk management contract gains and losses and deferred income taxes.