Rubellite Energy Corp. Reports Fourth Quarter 2025 Financial And Operating Results, 2025 Year-end Reserves

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And Provides Operations Update And First Quarter 2026 Guidance

Rubellite Energy Corp. ("Rubellite" or the "Company"), is pleased to report its fourth quarter 2025 financial and operating results and select information from the Company's independent year-end 2025 reserve report, evaluated by McDaniel and Associates Consultants Ltd. ("McDaniel") and provide an operations update and guidance for the first quarter of 2026. A copy of Rubellite's audited financial statements, Management Discussion and Analysis ("MD&A") and Annual Information Form ("AIF") for the year ended December 31, 2025 will be available on the Company's website at www.rubelliteenergy.com and SEDAR+ at www.sedarplus.ca.

This news release contains certain specified financial measures that are not recognized by GAAP and used by management to evaluate the performance of the Company 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 and Reserves Measures" in this news release and in the MD&A for further information on the definition, calculation and reconciliation of these measures and certain reserves measures. This news release also contains forward-looking information. See "Forward-Looking Information". Readers are also referred to the other information under the "Advisories" section in this news release for additional information.

FOURTH QUARTER AND ANNUAL 2025 OPERATIONAL AND FINANCIAL HIGHLIGHTS

Sales Production Volumes

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

Capital Expenditures

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

- Figure Lake gas plant: Spent $0.7 million in the fourth quarter and $4.1 million in 2025 to finish initial construction and expand the gas plant and gas gathering system at Figure Lake, bringing processing capacity to 6.4 MMcf/d by the fourth quarter of 2025.
- Land: Spent $0.3 million in the fourth quarter, bringing total land costs to $10.5 million in 2025. In the fourth quarter, the Company sold 7 sections of undeveloped land, subject to a retained gross overriding royalty, for $2.3 million, bringing total proceeds from the disposition of non-producing acreage in 2025 to $7.8 million, which funded other capital activities.
- Geological and geophysical costs: Spent $3.8 million in the fourth quarter and $4.9 million in 2025 to shoot new 3D seismic and acquire trade data to support the development of the Clearwater and other Mannville Stack prospects, including the evaluation of new zones.
- Abandonment and Reclamation: Spent $0.6 million in the fourth quarter and $1.9 million in 2025 on decommissioning, abandonment and reclamation activities and received seven reclamation certificates from the Alberta Energy Regulator ("AER") (2024 - one), with two additional reclamation certificates received subsequent to year-end.

Financial Performance

- Adjusted funds flow[(1)]:
  - $33.2 million ($0.35 per share) in the fourth quarter of 2025, up 5% from $31.6 million ($0.36 per share) in the fourth quarter of 2024.
  - $142.1 million ($1.52 per share) in 2025, up 52% (12% per share) from 2024 driven by a 97% increase in sales volumes and 20% lower cash costs, partially offset by a 10% decrease in average realized prices.
- Cash costs[(1)]:
  - $18.5 million or $15.41/boe in the fourth quarter of 2025, 21% lower on a per boe basis than the fourth quarter of 2024 (Q4 2024 - $18.6 million or $19.45/boe).
  - $78.6 million or $17.24/boe in 2025, 20% lower on a per boe basis than 2024 (2024 - $50.4 million or $21.68/boe).
- Net income:
  - $9.7 million ($0.10 per share) in fourth quarter of 2025 (Q4 2024 - $26.7 million net income or $0.31 per share).
  - $32.6 million ($0.35 per share) in 2025 (2024 - $50.0 million or $0.73 per share).

Balance Sheet and Liquidity

- Net debt[(1)]: $143.1 million at December 31, 2025, down 7% from $154.0 million at December 31, 2024, driven by $11.6 million of positive free funds flow[(1)] used to reduce net debt and other obligations.
- Available liquidity[(2)]: $46.0 million at December 31, 2025, based on a $140.0 million first-lien credit facility borrowing limit, less $92.6 million of bank borrowings and $1.4 million in letters of credit.

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

(2) See "Liquidity, Capitalization and Financial Resources - Capital Management" in the MD&A.

2025 GUIDANCE RECONCILIATION

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

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

(1) 2025 guidance dated November 5, 2025.

(2) Liquids means oil, condensate, ethane, propane and butane.

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

(4) Excludes abandonment and reclamation spending, land and acquisitions and geological expenditures, if any.

OPERATIONS UPDATE

Figure Lake

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

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

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

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

Subsequent to the end of the year, a single rig drilling program is continuing at the 8-26-61-16W4 pad (the '8-26 Pad') following up two successful step-out delineation wells drilled in 2024. During the first quarter of

2026, a total of 4 (4.0 net) primary producers, 1 (1.0 net) waterflood pilot producer and 1 (1.0 net) injector pair are expected to be drilled at the 8-26 Pad. A polymer producer and injector pilot pair is also planned for the 8-26 Pad, which are scheduled to drill over quarter end. Results to date on the 8-26 Pad have been positive, with the first well drilled recording an IP30 of 286 bbl/d and the second drill recording an IP15 of 335 bbl/d in the early stages of production.

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

Frog Lake

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

- Waseca North program: 14 (10.0 net) wells achieved average IP30/IP60 rates of 133/112 bbl/d, as compared to the 2025 McDaniel type curve(2) of 122/117 bbl/d and the 2024 McDaniel type curve(2) of 107/104 bbl/d
- Waseca South program: 7 (5.5 net) wells achieved average IP30/IP60 rates of 153/145 bbl/d, as compared to the 2025 McDaniel type curve(2) of 145/145 bbl/d and the 2024 McDaniel type curve(2) of 150/150 bbl/d.

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

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

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

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

East Edson

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

Other Exploration

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

(1) No development wells were excluded from the calculation of average results except by the criteria for producing days.

(2) Type curve assumptions are based on the total proved plus probable undeveloped reserves contained in the McDaniel Report as disclosed in the AIF available under the Company's profile on SEDAR+ at www.sedarplus.ca. Year-end 2024 McDaniel Figure Lake Tier 1 Type Curve type curve of 177 bbl/d (IP30) and 169 bbl/d (IP60) based on the reserves contained in the 2024 McDaniel Report, as disclosed in the Company''s 2024 AIF. "McDaniel Report" means the independent engineering evaluation of the heavy crude oil and conventional natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026.

OUTLOOK AND GUIDANCE

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

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

At Figure Lake:

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

At Ukalta:

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

At Frog Lake:

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

At East Edson:

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

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

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

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

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

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

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

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

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

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

(1) Includes one waterflood injection well.

(2) Excludes abandonment and reclamation spending, acquisitions and land and geological expenditures, if any.

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

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

(1) Liquids means oil, condensate, ethane, propane and butane.

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

(3) Excludes abandonment and reclamation, land, geological and acquisition expenditures, if any.

YEAR-END 2025 RESERVES HIGHLIGHTS

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

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

Other highlights from the McDaniel Report(1) include:

- Total proved reserves increased 0.5% (0.2 MMboe) to 32.9 MMboe from 32.7 MMboe and representing 62% of the Company's proved plus probable reserves (2024 - 62%).
- Proved developed producing reserves were 18.1 MMboe, an increase of 2% and representing 34% of the Company's proved plus probable reserves (2024 year-end proved developed producing reserves were 17.7 MMboe; 33% of total proved plus probable reserves).
- Proved plus probable developed producing reserves were 23.3 MMboe, representing 44% of total proved plus probable reserves (2024 year-end proved plus probable developed producing 23.0 MMboe; 43% of proved plus probable reserves).
- Rubellite's total capital expenditures(4) of $130.0 million (which excludes $0.5 million of corporate capital) resulted in total proved plus probable additions of 4.6 MMboe and included a change in future development capital of $21.2 million. The reserve additions resulted in finding and development ("F&D") costs(4) of $32.73/boe. Higher than normal cost of reserve additions were observed this year due to a negative technical revision in the Edson Joint Venture property, which offset the positive additions in the heavy oil properties. Rubellite had cash proceeds from dispositions of undeveloped land of $7.8 million which had no reserves assigned prior to the disposition.

- At the Eastern Heavy Oil cash generating unit ("CGU") level, exploration and development expenditures [(4)] totalled $100.5 million, land expenditures of $10.5 million, after adjusting for the $7.8 million of cash proceeds related to the sale of land with no reserves assigned or net book value, geological and geophysical spending was $4.9 million, and the change in future development capital for Rubellite's heavy oil assets was $36.4 million. With heavy oil reserve additions of 6.3 MMboe, the Adjusted Heavy Oil F&D costs per boe[(4)] on a 2P basis were $22.93/boe with a recycle ratio[(4)] of 2.0, based on a 2025 heavy oil operating netback[(4)] of $45.15/boe. For more details see section "Adjusted F&D Ratios".
- The McDaniel Report includes a total of 214 (167.2 net) booked undeveloped drilling locations, which are comprised of 139 (109.2 net) proved undeveloped and 75 (58.0 net) probable undeveloped locations. Of these, 111 (109.7 net) are in the Figure Lake area with 72 (71.1 net) that are proved undeveloped and 39 (38.6 net) probable undeveloped.
- Continued drilling success in 2025 in the Figure Lake property resulted in outperformance, in aggregate, relative to the 2024 type curves. In the McDaniel Report, IP30 rates were increased on Figure Lake Tier 1 and Tier 2 type curves to 201 bbl/d (2024 - 177 bbl/d) and 144 bbl/d (2024 - 120 bbl/d), respectively. In the Edwand sub-area of Figure Lake, which has it's own type curves, IP30 rates were also increased to 191 bbl/d (2024 - 175 bbl/d), as were proved plus probable estimated ultimate recoverable ("EUR") volumes to 125 Mboe per well (2024 - 115 Mboe per well).
- At Frog Lake, success in drilling, and executing well operational strategies to deal with sand production, resulted in both developed producing and undeveloped reserve adds in the GP formation. Four (3.0 net) GP wells were drilled in 2025 with developed producing reserves, with an additional 17 (8.5 net) booked undeveloped locations. Of these undeveloped locations, 7 (3.5 net) are proved undeveloped and 10 (5.0 net) are probable undeveloped. In the McDaniel Report, the GP type curve has an IP30 rate of 73 bbl/d and proved plus probable reserves of 85 Mboe.
- All abandonment, decommissioning and reclamation obligations are included in the McDaniel Report, consistent with year-end 2024. Decommissioning obligations for wells assigned reserves are forecast to occur at end of life while the additional costs expected to be incurred to abandon and reclaim non-reserve wells, facilities and pipelines are forecast in accordance with regulatory asset retirement obligation spending requirements for inactive wells.
- Rubellite's undeveloped land was independently assessed in the Seaton-Jordan Report[(3)], at $59.6 million, an increase of 22% from $48.8 million.
- Based on the three consultant average price (McDaniel, GLJ Ltd., Sproule Associates Limited) forecasts (the "Consultant Average Price Forecast") used by McDaniel, the net present value ("NPV") of Rubellite's total proved plus probable reserves (discounted at 10%) before income tax, was $651.5 million (2024 - $721.5 million). The 10% NPV10 decrease from year-end 2024 is related directly to the reduction in commodity price forecasts based on the Consultant Average Price Forecast, and to a lesser degree, the negative technical revisions in the Edson Joint Venture property, offset by positive reserve revisions and additions in the Company's heavy oil properties.
- Based on the Consultant Average Price Forecast, Rubellite's reserve-based net asset value ("NAV")[(4)] (discounted at 10%) at year-end 2025, is estimated at $556.6 million ($5.95 per share) as compared to $601.1 million ($6.47 per share) at year-end 2024. The reserve-based NAV is inclusive of the independent assessment of undeveloped land and net of the Company's total net debt[(4)] and other obligations[(4)], which includes $143.1 million of net debt and $16.2 million for the undiscounted amount of the other provision[(4)].

(1) "McDaniel Report" means the independent engineering evaluation of the Company's heavy crude oil, conventional natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026.

(2) Type curve assumptions are based on the total proved plus probable Undeveloped reserves contained in the McDaniel Report as disclosed in the Company's AIF which will be available under the Company's profile on SEDAR+ at www.sedarplus.ca.

(3) The value of Rubellite's undeveloped land was assessed by an independent third party, Seaton-Jordan & Associates Ltd., as at December 31, 2025 in a report dated January 26, 2026 (the "Seaton-Jordan Report"). Estimates of the value of Rubellite's undeveloped acreage was prepared in accordance with NI 51-101 5.9(1)(e) for purposes of the net asset value calculation and is based on past Crown land sale activity, adjusted for tenure and other considerations. No undeveloped land value is assigned where reserves have already been booked, even if the corresponding lease contains multiple prospective formations that have not yet been assigned reserves .

(4) Non-GAAP financial measure or non-GAAP ratio. See "Non-GAAP and Other Financial and Reserves Measures" in this news release.

YEAR-END 2025 RESERVES DATA

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

Corporate Reserves

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

(1) May not add due to rounding.

Reserves Value

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

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

(1) May not add due to rounding.

Price Forecast

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

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

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

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

Reserves Reconciliation

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

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

(1) May not add due to rounding.

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

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

F&D Costs and Ratios(1)

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

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

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

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

(2) Non-GAAP financial or reserve measure or non-GAAP ratio. See "Non-GAAP and Other Financial and Reserves Measures" in this news release.

(3) No lands with reserves assigned were acquired or disposed of in 2025.

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

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

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

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

Adjusted F&D Ratios[(1)]

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

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

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

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

NET ASSET VALUE ("NAV")

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

Pre-tax NAV(1) at December 31, 2025(2)

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

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

(2) Financial information is per Rubellite's 2025 audited consolidated financial statements.

(3) Proved plus probable developed and proved plus probable undeveloped reserve values per the McDaniel Report, including adjustments for risk management contracts. All abandonment and reclamation obligations, including future abandonment and reclamation costs for pipelines and facilities and non-reserve wells, are included in the McDaniel Report.

(4) Independent third-party estimate as per the Seaton-Jordan Report; excludes undeveloped lands where reserves are assigned.

(5) Common shares outstanding are net of shares held in trust.

(6) NAV per share is calculated by dividing the NAV by the number of issued and outstanding common shares, net of shares held in trust, at December 31, 2025.

SUMMARY OF ANNUAL RESULTS

($ thousands, except as noted)	2025	2024	2023	2022
Financial				
Oil and natural gas revenue	241,700	168,384	88,968	54,491
Net income and comprehensive income	32,557	49,973	18,561	24,605
Per share - basic(1)	0.35	0.73	0.31	0.47
Per share - diluted(1)	0.34	0.72	0.30	0.47
Total Assets	578,509	562,612	271,153	204,030
Cash flow from operating activities	128,796	95,788	55,391	23,870
Adjusted funds flow, including transaction costs(2)(6)	142,073	93,777	54,154	23,036
Per share - basic(1)(2)	1.52	1.37	0.90	0.44
Per share - diluted(1)(2)	1.48	1.35	0.89	0.44
Adjusted funds flow, before transaction costs(2)(6)	142,073	100,010	54,304	23,036
Per share - basic(1)(2)	1.52	1.46	0.90	0.44
Per share - diluted(1)(2)	1.48	1.43	0.89	0.44
Q4 annualized adjusted funds flow(2)(10)	132,660	143,420	68,280	32,580
Net debt to Q4 annualized adjusted funds flow ratio(2)(10)	1.1	1.1	0.7	0.9
Net debt(2)	143,143	154,020	50,984	28,228
Capital expenditures(2)				
Total capital expenditures(2)	130,502	108,906	71,530	94,207
Acquisitions(7)(8)	-	179,247	33,173	-
Dispositions(9)(11)	-	-	(7,990)	-
Total capital expenditures, after acquisitions and dispositions	130,502	288,153	96,713	94,207
Wells Drilled(3) - gross (net)	53 / 43.8	46 / 41.5	30 / 29.5	45 / 39.5
Common shares outstanding(1) (thousands)				
Weighted average - basic	93,283	68,667	60,346	52,093
Weighted average - diluted	96,036	69,716	61,075	52,471
End of period	93,593	93,044	62,456	54,826
Sales Production				
Heavy oil (bbl/d)(4)	8,402	5,685	3,302	1,670
Natural gas (MMcf/d)	22.4	3.6	-	-
NGL (bbl/d)(5)	365	69	-	-
Daily average sales production (boe/d)				

12,494

12,494

6,349

3,302

1,670

Average prices				
West Texas Intermediate ("WTI") ($US/bbl)	64.81	75.72	77.62	94.22
Western Canadian Select ("WCS") ($CAD/bbl)	75.14	83.52	79.46	98.49
AECO 5A Daily Index ($CAD/Mcf)	1.71	1.46	2.64	5.34
Rubellite average realized prices(2)(7)				
Oil ($/bbl)	71.38	78.92	73.82	89.38
Natural gas ($/Mcf)	1.84	2.01	-	-
NGL ($/bbl)	58.18	61.32	-	-
Average realized price(2) ($/boe)	53.00	72.46	73.82	89.38
Average realized price, after risk management contracts(2) ($/boe)	55.49	73.57	73.56	67.82
Operating netback ($/boe)				
Revenue	53.00	72.46	73.82	89.38
Royalties	(7.12)	(8.72)	(7.06)	(9.37)
Net operating costs(2)	(6.48)	(7.11)	(6.12)	(7.22)
Transportation costs	(5.18)	(7.03)	(7.50)	(7.30)
Operating netback(2)	34.22	49.60	53.14	65.49
Realized gain (loss) on risk management contracts	2.49	1.11	(0.26)	(21.56)
Total operating netback, after risk management contracts(2)	36.71	50.71	52.88	43.93

(1) Per share amounts are calculated using the weighted average number of basic or diluted common shares.

(2) Non-GAAP measure or ratio. See "Non-GAAP and Other Financial and Reserves Measures" contained in this news release.

(3) Well count reflects wells rig released during the period.

(4) Heavy oil sales production excludes tank inventory volumes.

(5) Liquids means oil, condensate, ethane and butane.

(6) Transaction costs of $6.2 million in 2024 (BMEC Acquisition and Recombination Transaction), and $0.1 million in 2023 (Clearwater Acquisition).

(7) The Recombination Transaction closed on October 31, 2024 for share consideration of $51.7 million. The BMEC Acquisition closed on August 2, 2024 for total consideration of $73.1 million.

(8) Clearwater acquisition closing on November 8, 2023 for cash consideration of $34.0 million, prior to purchase price adjustments.

(9) Royalty sale closed on December 8, 2023 for cash consideration of $8.0 million, prior to purchase price adjustments.

(10) Based on fourth quarter annualized adjusted funds flow before transaction costs relative to year-end net debt.

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

SUMMARY OF QUARTERLY RESULTS

	Three months ended December 31,		Twelve months e
	2025	2024	2025
Financial			
Oil and natural gas revenue	56,261	59,081	241,700
Net income and comprehensive income	9,700	26,747	32,557
Per share - basic(1)	0.10	0.31	0.35
Per share - diluted(1)	0.10	0.30	0.34
Total Assets	578,509	562,612	578,509
Cash flow from operating activities	30,900	39,402	128,796
Adjusted funds flow(2)	33,165	31,632	142,073
Per share - basic(1)(2)	0.35	0.36	1.52
Per share - diluted(1)(2)	0.34	0.36	1.48
Adjusted funds flow, before transaction costs(2)(6)	33,165	35,855	142,073
Per share - basic(1)(2)	0.35	0.41	1.52
Per share - diluted(1)(2)	0.34	0.40	1.48
Q4 annualized adjusted funds flow(2)(7)	132,660	143,420	132,660
Net debt to Q3 annualized adjusted funds flow ratio(2)(7)	1.1	1.1	1.1
Net debt(2)	143,143	154,020	143,143
Capital expenditures(2)			
Total capital expenditures(2)	39,037	35,537	130,502
Acquisitions(8)(9)	-	68,467	-
Total capital expenditures, after acquisition and dispositions(2)	39,037	104,004	130,502
Wells Drilled(3) - gross (net)	16 / 13.5	15 / 13.0	53 / 43.8
Common shares outstanding(1) (thousands)			
Weighted average - basic	94,488	87,655	93,283
Weighted average - diluted	97,478	88,546	96,036
End of period	93,593	93,044	93,593
Sales Production			
Heavy Oil (bbl/d)(4)	8,295	7,754	8,402
Natural gas (Mcf/d)	25,884	14,140	22,361
NGL (bbl/d)(5)	433	275	365
Daily average sales production (boe/d)			

13,042

10,386

12,494

Average prices			
West Texas Intermediate ("WTI") ($US/bbl)	59.14	70.27	64.81
Western Canadian Select ("WCS") ($CAD/bbl)	66.88	80.74	75.14
AECO 5A Daily Index ($CAD/Mcf)	2.34	1.48	1.71
Rubellite average realized prices[(2)(6)]			
Oil ($/bbl)	63.32	46.97	71.38
Natural gas ($/Mcf)	2.47	2.01	1.84
NGL ($/bbl)	51.93	61.32	58.18
Average realized price[(2)] ($/boe)	46.89	61.83	53.00
Average realized price, after risk management contracts[(2)] ($/boe)	49.20	65.14	55.49
Operating netback ($/boe)			
Revenue	46.89	61.83	53.00
Royalties	(6.14)	(8.10)	(7.12)
Net operating costs[(2)]	(5.80)	(6.84)	(6.48)
Transportation costs	(4.57)	(6.01)	(5.18)
Operating netback[(2)]	30.38	40.88	34.22
Realized gain on risk management contracts	2.31	3.31	2.49
Total operating netback, after risk management contracts[(2)]	32.69	44.19	36.71

(1) Per share amounts are calculated using the weighted average number of basic or diluted common shares.

(2) Non-GAAP measure or ratio. See "Non-GAAP and Other Financial and Reserves Measures" contained in this news release.

(3) Well count reflects wells rig released during the period.

(4) Heavy oil sales production excludes tank inventory volumes.

(5) Liquids means oil, condensate, ethane and butane.

(6) Before risk management contracts; supplementary financial measure. See "Non-GAAP and Other Financial and Reserves Measures".

(7) Based on Q4 2025 and Q4 2024 annualized adjusted funds flow before transaction costs relative to period end net debt. Non-GAAP financial measure and ratio.

(8) The Recombination Transaction closed on October 31, 2024 for share consideration of $51.7 million. The BMEC Acquisition closed on August 2, 2024 for total consideration of $73.1 million, prior to purchase price adjustments.

(9) In Q4 2025, the Company disposed of non-producing acreage for cash consideration of $2.3 million (2025 - $7.8 million) with a net book value of nil, resulting in a gain on disposition of assets of $7.8 million reported in the Company's statement of income and other comprehensive income.

ABOUT RUBELLITE

The Company is a Canadian energy company headquartered in Calgary, Alberta which, through its operating subsidiary, Rubellite Energy Inc. is engaged in the exploration, development, production and marketing of its diversified asset portfolio which includes heavy crude oil from the Clearwater and Mannville Stack Formations in Eastern Alberta utilizing multi-lateral drilling technology, liquids-rich conventional natural gas assets in the deep basin of West Central Alberta, and undeveloped bitumen leases in Northern Alberta. The Company is pursuing a robust organic growth plan focused on superior corporate returns and 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 Toronto Stock Exchange has neither approved nor disapproved the information contained herein.

ADVISORIES

RESERVES DATA AND INDUSTRY METRICS

Reserves Data

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

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

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

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

Industry Metrics

This news release 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. See "Non-GAAP and Other Financial and Reserves Measures" in this news release for a description of these industry metrics.

BOE VOLUME CONVERSIONS

Barrel of oil equivalent ("boe") may be misleading, particularly if used in isolation. In accordance with 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.

ABBREVIATIONS

The following abbreviations used in this news release have the meanings set forth below:

bbl	barrels
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousands of barrels of oil equivalent
MMboe	millions of barrels of oil equivalent
Mcf	thousand cubic feet
MMcf	million cubic feet
MMcf/d	million cubic feet per day
PDP	proved developed producing reserves
P+PDP	proved plus probable developed producing reserves
1P	total proved reserves
2P	total proved plus probable reserves

OIL AND GAS RESERVE DEFINITIONS

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

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

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

INITIAL PRODUCTION RATES

Any references in this news release to initial production rates are useful in confirming the presence of hydrocarbons; however, such rates are not determinate 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.

NON-GAAP AND OTHER FINANCIAL AND RESERVES MEASURES

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

Non-GAAP Financial Measures

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

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

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

(1) Non-GAAP supplementary measure. See "Supplementary Measures" contained in this news release.

Presented below are capital expenditures by CGU:

	Three months ended December 31,		Twelve months ended Decer	
($ thousands)	2025	2024	2025	2024
Total capital expenditures:				
Eastern Heavy Oil	31,829	34,710	115,890	105,110
West Central	7,075	699	14,083	699
Corporate	133	128	529	3,097
Total capital expenditures, before corporate spending	39,037	35,537	130,502	108,906
Exploration and development spending:				
Eastern Heavy Oil	27,713	33,699	100,487	101,033
West Central	7,075	699	14,083	699
Exploration and development spending:	34,788	34,398	114,570	101,732

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

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

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

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

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

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

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

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

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

($ thousands)	As of December 31, 2025	As of December 31, 2024
Current assets	35,181	44,714
Current liabilities	(70,413)	(74,680)
Working capital deficit	35,232	29,966
Risk management contracts - current asset	5,828	9,783
Risk management contracts - current liability	(327)	(2,765)
Right of use liability - current liability	(389)	(357)
Share-based compensation liability - current liability	(4,694)	(5,357)
Decommissioning obligations - current liability	(1,340)	(2,000)
Other provision - current liability	(3,750)	(3,750)
Adjusted working capital deficit(1)	30,560	25,520
Bank indebtedness	92,583	108,500
Term loan (principal)	20,000	20,000
Net debt(2)	143,143	154,020
Other provision (undiscounted obligation)(3)	16,191	19,941

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

(2) Excludes other non-current liabilities.

(3) Other provision at the undiscounted obligation is presented in the financial statements and used in the NAV calculation in this news release.

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

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

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

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

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

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

	Three months ended December 31,		Twelve months ended De	
($ thousands, except per share and per boe amounts)	2025	2024	2025	2024
Adjusted funds flow	33,165	31,632	142,073	93,77
Capital expenditures, including land, corporate and other	(39,037)	(35,537)	(130,502)	(108,9
Free funds flow	(5,872)	(3,905)	11,571	(15,12

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.

Net Asset Value ("NAV"): Total proved plus probable reserves as per the McDaniel Report, plus independently verified third party valuation of undeveloped lands, less net debt and the other provision at an undiscounted value. This measure is used to show the net asset value of the Company at a point in time under which the reserves are produced at forecasted future prices and costs.

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.

Average realized oil price after risk management contracts: calculated as the average realized price less the realized gain or loss on risk management contracts.

Adjusted funds flow per share: calculated using the weighted average number of basic and diluted shares outstanding used in calculating net income (loss) per share.

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

Net debt to adjusted funds flow ratio: net debt to adjusted funds flow ratios is adjusted to calculate adjusted funds flow 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.

Supplementary Financial Measures

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

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

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

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

"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.

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

"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 oil production.

Reserves Measures

This news release contains the terms FDC, F&D costs per boe, FD&A costs per boe, Adjusted FD&A costs per boe, recycle ratio and replacement. These terms have been calculated by management and do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. These measures have been calculated on a total company basis and based on the Eastern Heavy Oil CGU. Such measures have been included in this news release 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 measures should not be unduly relied upon.

Future Development Capital ("FDC"): comprised of total exploration and development costs incurred on reserves that are categorized as development reserves. For this calculation, development capital includes land expenditures and excludes acquisitions and dispositions.

Finding and development ("F&D") costs per boe: calculated as the sum of the non-GAAP measure "total capital expenditures" (as calculated above) less corporate spending, plus the change in FDC for the period divided by the change in reserves that are characterized as development for the period which takes into account reserve revisions during the period. This measure is then divided by the Company's total sales production on a per barrel basis. The aggregate of the total capital expenditures, less corporate spending, incurred in during the period and changes during that period in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that period.

Finding, development and acquisition ("FD&A") costs per boe: calculated as the sum of development costs, acquisition and disposition costs and the change in FDC for the period, divided by the reserves within the applicable reserves category, including changes due to acquisitions and dispositions (both for reserves and the net book value component).

Adjusted finding and development ("F&D") costs per boe: calculated as the sum of development costs, adjusted for the cash proceeds of acquisitions and dispositions, rather than the net back value component used in determining F&D costs. The change for the period, is then divided by the reserves within the applicable reserves category.

Recycle ratio: calculated by dividing the non-GAAP measure "operating netback" by F&D costs per boe. The recycle ratio compares the netback from existing reserves to the cost of finding new reserves and may not accurately indicate the investment success unless the replacement reserves are equivalent quality as the produced reserves.

Production replacement: measures how much annual production has been replaced by new reserve additions. It is calculated by taking the total change in reserves on a per boe basis dividend by the annual sales production on a per boe basis.

FORWARD-LOOKING INFORMATION

Certain information in this news release including management's assessment of future plans and operations, and including the information contained under the headings "Operations Update" and "Outlook and Guidance" may constitute forward-looking information or statements (together "forward-looking information") under applicable securities laws. The forward-looking information includes, without limitation, statements with respect to: future capital expenditures, production and various cost forecasts; the anticipated sources of funds to be used for capital spending; expectations as to future exploration, development and drilling activity, and the benefits to be derived from such drilling including drilling techniques, pilot projects and production growth; the plan to advance strategic initiatives including multiple enhanced oil recovery pilots, exploration activities, new land capture, capital spending activities in the Company's core properties at Figure Lake, Frog

Lake and East Edson, anticipated average heavy oil sales volumes and total production sales volumes in the first quarter of 2026; the expectation that capital spending activity will be funded from adjusted funds flow, with excess free funds flow to reduce net debt and for other balance sheet obligations; operating and transportation cost forecasts for the first quarter of 2026; the expectation that blending demand for Clearwater and Mannville Stack heavy oil will continue to translate into attractive offsets to WCS benchmark pricing, planned ARO spending; Rubellite's business plan; the anticipated timing for providing full year guidance with the issuance of its Q1 2026 results in May; and including the forward-looking information contained under the heading "About Rubellite".

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

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

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