# 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 nine months ended September 30, 2026, 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 interim consolidated financial statements and accompanying notes for the three and nine months ended September 30, 2026 as well as the audited consolidated financial statements and accompanying notes for the year ended December 31, 2025. Disclosure, which is unchanged from the December 31, 2025 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 ("IFRS") as issued by the International Accounting Standards Board. The date of this MD&A is November 6, 2026.*

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

### NATURE OF BUSINESS

The Company is a Canadian energy company headquartered in Calgary, Alberta engaged in the exploration, development, production and marketing of heavy crude oil from the Clearwater and Mannville Stack Formations in Eastern Alberta, 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".

## QUARTERLY OPERATIONAL AND FINANCIAL HIGHLIGHTS

### *Operational Highlights*

- **East Edson disposition:** On September 8, 2026, the Company completed the sale of its non-operated 50% working interest in the East Edson property in West Central Alberta, (the "East Edson Disposition"). The Company received 2.1 million common shares of Topaz Energy Corp. ("Topaz"), having a deemed value of $67.0 million as consideration for the East Edson Disposition. East Edson averaged approximately 3,460 boe/d of sales production during the 69 days of the third quarter that preceded the East Edson Disposition. Following the East Edson Disposition, Rubellite's sales production is approximately 90% heavy oil, with the remaining production being solution gas and natural gas liquids ("NGL") related to heavy oil production.

- **Total sales production:** Averaged 12,128 boe/d in the third quarter of 2026 (73% heavy oil and NGL), down 10% from 13,406 boe/d (67% heavy oil and NGL) in the second quarter of 2026, reflecting the East Edson Disposition and natural declines in the West Central area.

- **Heavy oil sales production:** Averaged 8,542 bbl/d in the third quarter of 2026, consistent with the 8,534 bbl/d of sales production in the second quarter of 2026. During the quarter, 18 (15.5 net) heavy oil wells were brought on production, and the Company established tank inventory at new pads and added to sales volumes at Figure Lake and Frog Lake, with initial production rates varying across the program. An additional 4 (4.0 net) wells were awaiting tie-in, or recovery of drilling fluids, and not yet contributing to sales production.

- **Exploration and development spending[(1)(3)]:** Spent $41.3 million in the third quarter, which included the drilling and completion of 8 (8.0 net) primary open hole multi-lateral ("OHML") Clearwater development wells at Figure Lake and 3 (2.5 net) OHML Waseca South development wells, 4 (3.5 net) Sparky and 2 (1.5 net) GP single leg lined circulation string wells ("SLLC") at Frog Lake.

- **Land and geological and geophysical spending:** Spent $1.6 million on land to capture acreage in core areas and for exploration prospects and $0.4 million on geological and geophysical activities related to core testing to inform enhanced oil recovery pilot work and various seismic data purchases.

- **Abandonment and reclamation:** Spent $0.2 million on decommissioning, abandonment and reclamation activities in the third quarter and received one reclamation certificate from the Alberta Energy Regulator ("AER"). Two more certificates were received early in the fourth quarter, bringing the 2026 total to six as of November 6, 2026.

### *Financial Highlights*

- **Adjusted funds flow before transaction costs[(1)]**: $35.8 million ($0.38 per share) in the third quarter of 2026, an increase from the second quarter of 2026 (Q2 2026 - $35.2 million or $0.38 per share). Lower natural gas and NGL sales volumes and higher royalties and net operating costs were largely offset by lower realized losses on risk management contracts and lower G&A expenses.

- **Cash costs[(1)]**: $22.3 million or $19.97/boe in the third quarter of 2026, representing a 4% increase on a per boe basis as compared to the second quarter of 2026 (Q2 2026 - $23.5 million or $19.29/boe). The increase was driven by higher net operating and transportation costs due to poor weather-related lease and road conditions at Figure Lake and Frog Lake that continued into the third quarter and the disposition of the lower per unit cost East Edson assets, partially offset by lower G&A and finance expenses.

- **Net loss:** $27.1 million ($0.29 loss per share) in the third quarter of 2026, primarily driven by a $43.7 million unrealized loss on risk management contracts as forward commodity prices increased, partially offset by a $20.8 million deferred tax recovery, of which $13.0 million related to the East Edson Disposition.

- **Net debt[(1)]:** $109.0 million at September 30, 2026, down from $158.1 million at June 30, 2026, mainly due to the receipt of Topaz shares, valued at $59.7 million at September 30, 2026, as consideration for the East Edson Disposition. This was partially offset by negative free funds flow of $7.9 million in the third quarter, as capital spending of $43.4 million exceeded adjusted funds flow, after transaction costs, of $35.4 million. Since December 31, 2025, net debt has decreased 24% from $143.1 million at December 31, 2025, with the East Edson Disposition proceeds partially offset by negative free funds flow of $15.9 million, as capital expenditures of $119.9 million exceeded adjusted funds flow, after transaction costs, of $104.1 million in the first nine months of 2026, and $9.6 million of payments for other obligations.

- **Available liquidity[2]:** Following the East Edson Disposition, the first-lien credit facility borrowing limit was reconfirmed at $160.0 million. As at September 30, 2026, available liquidity was $40.6 million, based on the $160.0 million borrowing limit, less $118.0 million of bank borrowings and $1.4 million in letters of credit.

(1) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(2) See "Liquidity, Capitalization and Financial Resources - Capital Management".
(3) Frog Lake Energy Resources Corp. ("FLERC") has the option on wells drilled at Frog Lake to elect for a 50% working interest or earn a gross overriding royalty. Three wells that were drilled or began drilling in Q3 2026 are reported and forecast at 100% working interest, with total spending of $4.1 million, as FLERC's elections remained outstanding at November 6, 2026. These wells were not on sales production at September 30, 2026.

## OPERATIONS UPDATE

***Figure Lake***

*Primary Development Update:*

In the third quarter, Rubellite drilled and rig released 8 (8.0 net) primary OHML development wells targeting the Wabiskaw Member of the Clearwater Formation:

- 3 (3.0 net) at the 12-28-62-18W4 surface pad (the "12-28 Pad")
- 4 (4.0 net) at the 14-22-63-18W4 surface pad (the "14-22 Pad")
- 1 (1.0 net) at the 13-26-61-16W4 surface pad (the "13-26 Pad")

Production results for primary wells drilled to date in 2026 averaged[1] IP30/60 rates of 150 bbl/d (16 wells)/128 bbl/d (14 wells), as compared to the 2025 McDaniel Tier 1 type curve[2] of IP30/60 of 201/193 bbl/d[2] and Tier 2 type curve[2] of IP30/60 of 144/138 bbl/d[2]. Five (5.0 net) wells drilled from the 14-22 Pad were classified by McDaniel[2] as Tier 2 and the results are reflected in the average results obtained. Currently one rig is contracted to continue drilling operations at Figure Lake through the remainder of the year.

Wet weather conditions persisted through the third quarter, negatively impacting operating costs. To mitigate increased operating costs, capital costs, well downtime and oil sales trucking disruptions related to weather events such as the unseasonably wet weather experienced during the second and third quarters this year, Rubellite spent $1.1 million during the third quarter to successfully apply several technical solutions to improve existing all-weather road and pad infrastructure. Based on the cost/benefit analysis to date, future lease construction of new pads will include the application of soil cement in preparation for drilling operations and long-term production, offsetting costs historically incurred in the drilling operation to maintain lease conditions while drilling, and at the same time reducing future maintenance costs and operations downtime.

*Enhanced Oil Recovery ("EOR") Update:*

Water injection commenced in March 2026 at the first Figure Lake waterflood pilot producer-injector pair drilled in the fourth quarter of 2025 on the 9-35-63-18W4 Pad (the "9-35 Pad"). Results continue to be encouraging with positive water injection performance to date and production rates meeting McDaniel's waterflood response forecast from the year end 2025 reserve evaluation[3].

The second and third EOR pilots at Figure Lake are both located at the 8-26-61-16W4 surface pad (the "8-26 Pad"), where 2 (2.0 net) 8-leg OHML producers are paired with dedicated injectors. Water injection commenced in both injectors in late September.

In addition to the dedicated line drive injector pilots, two multi-lateral horizontal producer-to-injector conversions were advanced on two separate pads at Figure Lake and water injection rates have continued to ramp up late in the third quarter following surface equipment modifications. These producer-to-injector conversion pilots will assist in evaluating the effectiveness of repressurization through waterflood where primary-focused multi-lateral drilling development has already occurred.

Lab testing for the selection of an appropriate polymer for a polymer flood pilot was advanced during the third quarter, with field trials expected to begin in 2027 after installation of dedicated blending equipment.

Up to five (5.0 net) producer / injector pairs and a dedicated source well are planned for a waterflood Commercial Demonstration Pad at 7-8-63-17W4 (the "7-8 Pad") beginning late in the first quarter of 2027. The intent of the commercial demonstration pad is to verify source water deliverability and quality, to evaluate the effectiveness of several waterflood well pair configuration designs, and to pilot water injection for repressurization in proximity to an existing primary well. The Commercial Demonstration Pad is an important next step to refine and optimize the full scale development plan for the Clearwater at Figure Lake.

*Figure Lake Sparky*

The exploration well (1.0 net) targeting the Sparky Formation drilled in the fourth quarter of 2025 was suspended in August due to wet road conditions. Continuous production from the discovery well requires the construction of an all-season road and associated bridge improvements, which are partially scheduled for the fourth quarter of 2026 and expected to be completed following spring break up. Follow up development drilling, with the potential to pilot waterflood in the Sparky pool, is planned for the summer of 2027.

***Frog Lake[4]***

*Waseca Update - Open Hole Multi-lateral Horizontals:*

During the third quarter, Rubellite drilled and rig released 3 (recorded and forecast at 2.5 net) OHML wells targeting the Waseca Formation. Results to date of Waseca wells drilled at Frog Lake in 2026 are:

- Waseca North: Average[1] IP30/IP60 rates obtained for Waseca North wells drilled to date in 2026 are 118 bbl/d (5 wells)/106 bbl/d (5 wells), as compared to the 2025 McDaniel type curve[2] of 122/117 bbl/d.

- Waseca South: Average[1] IP30/IP60 rates obtained for Waseca South wells drilled to date in 2026 are 98 bbl/d (3 wells)/81 bbl/d (3 wells), as compared to the 2025 McDaniel type curve[2] of 145/145 bbl/d.

Two (forecast at 2.0 net) 20,000m OHML Waseca North wells are planned for the fourth quarter of 2026. Working interest elections by Frog Lake Energy Resources Corp. ("FLERC") are expected to be received in January 2027.

*GP and Sparky Update - Single Leg Lined Laterals with Circulation Strings:*

Rubellite has continued to positively advance the use of single leg lined lateral horizontal wells equipped with high velocity circulation strings ("SLLC wells") to enable consistent production of heavy oil with solids from the less consolidated GP and Sparky sands of the Mannville Stack. Through the third quarter of 2026, Rubellite has drilled and placed on production 4 (recorded and forecast at 3.0 net) GP wells and 3 (recorded and forecast at 2.5 net) Sparky wells. Results to date from both zones have been encouraging. The GP wells averaged[1] IP30 rates

of 101 bbl/d (three wells) vs. the McDaniel type curve[2] for the GP of 73 bbl/d. Sparky wells drilled in 2026 and on production to date averaged[1] IP30 rates of 118 bbl/d (three wells). Heavy oil production rates from the SLLC wells have improved on average ~30% through their second months of production as operations are optimized and wormholes are postulated to be developing in the unconsolidated sand reservoirs.

With the ongoing one rig delineation drilling program that spans across Rubellite's land base at Frog Lake, an additional 6 (forecast at 5.0 net) GP and 3 (forecast at 1.5 net) Sparky SLLC wells will be drilled and on production in the fourth quarter, for a total of 16 (forecast at 12.0 net) SLLC wells in 2026. A number of these working interest elections will be received from FLERC in January and through March 2027.

***Marten Hills***

Following the acquisition of an additional 30% working interest at Marten Hills which closed on June 30, 2026, 1 (0.6 net) injection well and 1 (0.6 net) water source well are scheduled to be drilled in the fourth quarter of 2026 to expand the existing waterflood to all four wells on the 12-35 Pad at Marten Hills. Additional water injection to provide pressure support for Rubellite's remaining 7 (4.2 net) primary producers is anticipated for 2027.

***Ukalta***

Source water management and modification of surface facilities is underway to increase the volume of water available for injection in the converted multi-lateral waterflood injector that commenced injection in the second quarter of 2026.

***Other Exploration***

In addition to ongoing zonal delineation activity in the GP and Sparky zones at Frog Lake and the Sparky zone at Figure Lake, Rubellite continued to advance several early-stage exploration prospects including land capture and play concept de-risking, while maintaining a disciplined approach to risked capital exposure.

*Bayhurst*

One (1.0 net) exploration OHML well with ~2,750m of measured depth open hole was drilled at Bayhurst, Saskatchewan in the first quarter of 2026 and has been on an extended production test for several months at 30 bbl/d. Two additional follow up wells at Bayhurst (2.0 net) are planned for the fourth quarter of 2026 to further delineate the reservoir, confirm the optimal well design and secure land tenure.

*Calling Lake*

As previously disclosed, the 4 leg OHML horizontal exploration well drilled in 2024 has underperformed expectations due to what is suspected to be a collapsed wellbore. A resumption of drilling operations is planned for the fourth quarter where a single lined lateral will be drilled from the existing well and equipped with the SLLC design to lift solids, similar to the well configuration used in the Mannville Stack at Frog Lake.

(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 most recent AIF available under the Company's profile on SEDAR+ at www.sedarplus.ca. "McDaniel Report" means the independent engineering evaluation of the heavy crude oil and natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2025 and a preparation date of March 10, 2026.
(3) The 00/12-35-63-18W4 well was recognized in the McDaniel report as Proved Developed Producing with a Proved Non-Producing Waterflood response wedge.
(4) FLERC has the option on wells drilled in Frog Lake to elect for a 50% working interest in the well or alternatively earn a gross overriding royalty. As at November 6, 2026, FLERC's elections on one Sparky well and one Waseca South well drilled in Q3 2026, and one GP well rig released in October 2026, remain outstanding and the wells are reported at 100% working interest, with total spending of $4.1 million, pending those elections. These three wells were not on sales production as at September 30, 2026 and are forecasted at 100% working interest until the election is made which is expected in late November 2026.

## OUTLOOK AND GUIDANCE

With the increased liquidity as a result of the East Edson Disposition, the closing of the swap transaction to increase its working interest at Marten Hills, and higher anticipated average working interest in the ongoing Frog Lake drilling program, Rubellite has increased its capital spending forecast for the fourth quarter of 2026 to $31 to $41 million, bringing the total exploration and development spending[(1)] forecast for 2026 to $145 to $155 million, up from previous guidance of $125 to $135 million. Total capital spending can vary by up to approximately $10 million depending on partner elections at Frog Lake.

In addition to development drilling in its core heavy oil operating areas, Rubellite's remaining 2026 capital spending will support longer term EOR and exploration initiatives, including: (1) drilling a waterflood injector and a water source well at Marten Hills to expand the waterflood on the 12-35 Pad; (2) one or more waterflood repressurization pilots at pads in Figure Lake that were originally developed for primary production only; (3) preparation for a new Commercial Waterflood Demonstration Pad at Figure Lake; (4) advancing polymer testing and polymer injection plans at Figure Lake and Frog Lake; and (5) activities to advance the evaluation of two exploration plays where Rubellite has material land capture.

Forecast core development property capital activity for the fourth quarter of 2026 is detailed below:

At Figure Lake:

- Drilling and completion of 5 (5.0 net) 15,000m, Clearwater primary development wells;
- Installation of a permanent bridge and a portion of required all-weather road upgrades to establish year-round production for the Sparky pool discovery;
- Pad preparation for the Commercial Waterflood Demonstration Pad at 7-8-63-17W4 to evaluate waterflood implementation at scale;
- Surface and downhole equipping activities related to one mature multi-lateral producer to waterflood injector conversion; and
- Additional core testing to continue to inform EOR initiatives.

At Frog Lake:

- Drilling and completion of 11 (forecast 8.5 net) wells: 6 (forecast 5.0 net) targeting the GP, 3 (forecast 1.5 net) targeting the Sparky and 2 (forecast 2.0 net) targeting the Waseca North; and
- Special core testing on the core cut during the third quarter, to inform EOR initiatives.

At Marten Hills:

- Drilling of 1 (0.6 net) waterflood injector and 1 (0.6 net) water source well to expand the 12-35 Pad waterflood, and construction to expand the other two Marten Hills pads ahead of 2027 waterflood expansion drilling.

The increased spending forecast relative to prior guidance is related to (1) known and forecast lower partner working interest participation elections at Frog Lake; (2) acceleration of waterflood expansion to the fourth quarter at Marten Hills; (3) accelerated exploration activity to the fourth quarter; (4) all-season pad and road infrastructure upgrades for existing pads during the third quarter and enhanced construction of new pads during the fourth quarter for the 2027 drilling program; and (5) bespoke capital activity overages in the third quarter, a portion of which compensation from the contractor is being sought.

At Frog Lake, Rubellite's 50% working interest partner ("FLERC" or "the Partner") can elect, on a well by well basis, to participate in a 50% working interest position, or not to participate and revert to an overriding royalty position. Wells drilled but still pending an election are accounted for at 100% WI until the election is received, including three wells with Q3 capital activity (two wells drilled in Q3 and one well rig released on October 3rd) with elections due later in November. If adjustments are required when the elections are received they will be made at that time. FLERC elections added a net $2.7 million to Q3 capital relative to prior guidance assumptions: $1.7 million on two wells where the Partner elected not to participate, $2.2 million on wells held at 100% pending elections due November 23, 2026, less $1.2 million adjusted for wells drilled in Q2 and recorded at 100% and the Partner made its election to participate during Q3. Historic guidance was predicated on FLERC participating at 50% working interest. Since Rubellite acquired the property in 2024, the Partner has historically participated in 57% of the wells elected to date, resulting in Rubellite having a 72% average working interest in drilling operations. On a prospective basis, guidance will assume a 75% average working interest (the Partner participating in half the wells). Depending on the Partner's elections due before year-end reporting, Frog Lake capital could vary by up to approximately $10 million, from FLERC participating in all of these wells to participating in none.

Proactively, in its core operating areas, Rubellite is investing to upgrade select road and pad infrastructure to ensure all-season access and continued operations, mitigating increased operating costs, capital costs and well downtime due to future weather events. Rubellite had three bespoke well events that increased Q3 capital by approximately $2.8 million in aggregate. At Frog Lake, a SLLC well had to be junked, abandoned and redrilled in the quarter. At Figure Lake, mechanical drilling challenges on an OHML well resulted in multiple fishing attempts and ultimately lost tools downhole, and a geologic anomaly at the toe of one of the legs in an OHML well resulted in significant OBM losses.

Exploration activity is being accelerated into Q4/26, adding $2.8 million to forecast capital with two Bayhurst exploration wells (up from one well in the prior forecast) and a lined lateral circulation string well at Calling Lake now planned in the fourth quarter.

Additional capital spending is anticipated for land capture and seismic purchases.

For 2026, heavy oil sales volumes are forecast to average 8,630 to 8,730 bbl/d, 2% to 4% higher than 2025, while total production sales volumes, including natural gas and NGL volumes, are forecast to average 12,230 to 12,330 boe/d, reflecting the East Edson Disposition on September 8, 2026. Fourth quarter heavy oil sales are forecast to average a record 8,800 to 9,200 bbl/d, while total sales volumes are expected to average 9,700 to 10,100 boe/d, including natural gas production conserved and sold at Figure Lake.

Operating costs are forecast to average $8.00 to $8.50/boe for the fourth quarter of 2026, and transportation costs are forecast to average $6.25 to $6.75/boe, reflecting increased fuel surcharges for trucked oil and the sale of East Edson where operating and transportation costs for natural gas are significantly lower than Rubellite's heavy oil properties. Heavy oil wellhead differentials are forecast to average $6.50 to $7.50/bbl, assuming diluent pricing consistent with the current forward curve. Royalties are expected to increase as a percentage of revenue, averaging 16.0% to 16.5%, given the higher forecast reference oil prices.

Rubellite will continue to address end of life asset retirement obligations ("ARO"), with $0.7 million of operated abandonment and reclamation expenditures planned for the remainder of 2026. Total forecast abandonment and reclamation spending for 2026 of $1.4 million exceeds the Company's AER area-based mandatory 2026 spending requirement of $1.3 million.

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

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

| | Q1 - Q3 2026 | | Q4 2026 | | Full year 2026 | |
|---|---|---|---|---|---|---|
| | **Capital Expenditures (millions)[1]** | **# of wells (*gross/net*)** | **Capital Expenditures (millions)[1]** | **# of wells (*gross/net*)** | **Capital Expenditures (millions)[1]** | **# of wells (*gross/net*)** |
| Figure Lake[2] | | 25 / 25.0 | | 5 / 5.0 | | 30 / 30.0 |
| Frog Lake | | 17 / 13.5 | | 11 / 8.5 | | 28 / 22.0 |
| Marten Hills | | -/- | | 2 / 1.2 | | 2 / 1.2 |
| East Edson | | 2 / 1.0 | | - / - | | 2 / 1.0 |
| Other Exploration | | 1 / 1.0 | | 3 / 3.0 | | 4 / 4.0 |
| Total | **$114** | **45 / 40.5** | **$31 - $41** | **21 / 17.7** | **$145 - $155** | **66 / 58.2** |

(1) Excludes corporate expenditures, abandonment and reclamation spending, land and geological expenditures, if any.
(2) 4 (4.0 net) wells drilled in H1 2026 were the EOR pilot producer-injector pairs on the 8-26 Pad at Figure Lake.

Rubellite's financial and operational guidance for full year 2026 is presented in the table below:

| | Previous Full Year 2026 Guidance[1] | Q4 2026 Guidance | Full Year 2026 Guidance |
|---|---|---|---|
| Sales production (boe/d) | 12,000 - 12,600 | 9,700 - 10,100 | 12,230 - 12,330 |
| Production mix (% oil and NGL) | 73% | 90% | 73% |
| Heavy oil sales production (bbl/d) | 8,500 - 9,200 | 8,800 - 9,200 | 8,630 - 8,730 |
| Exploration and development spending ($ millions)[2][3] | $125 - $135 | $31 - $41 | $145 - $155 |
| Heavy oil wellhead differential ($/bbl)[2] | $5.25 - $5.75 | $6.50 - $7.50 | $5.25 - $5.75 |
| Royalties (% of revenue)[2] | 14.5% - 15.5% | 16.0% - 16.5% | 14.5% - 15.5% |
| Net operating costs ($/boe)[2] | $7.50 - $8.00 | $8.00 - $8.50 | $7.50 - $8.00 |
| Transportation costs ($/boe)[2] | $5.50 - $6.00 | $6.25 - $6.75 | $5.50 - $6.00 |
| General and administrative costs ($/boe)[2] | $3.50 - $4.00 | $3.00 - $3.25 | $3.00 - $3.25 |

(1) Previous full year 2026 guidance dated September 8, 2026 reflecting the East Edson Disposition.
(2) Non-GAAP financial measure, non-GAAP ratio or supplementary financial measure. See "Non-GAAP and Other Financial Measures".
(3) Excludes abandonment and reclamation spending, land and geological expenditures.

## THIRD QUARTER 2026 FINANCIAL AND OPERATING RESULTS

### Capital Expenditures

Rubellite uses capital expenditures to measure its capital investments compared to the Company's annual budgeted expenditures related to both property, plant and equipment assets ("PP&E") and exploration and evaluation assets ("E&E") assets. The capital budget excludes acquisition and disposition activities. "Capital Expenditures" is not a standardized measure; therefore, it 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 September 30, | | | | | |
|---|---|---|---|---|---|---|
| | **2026** | | | 2025 | | |
| (*$ thousands*) | **E&E** | **PP&E** | **Total** | E&E | PP&E | Total |
| Drilling and completions | **435** | **35,104** | **35,539** | 42 | 27,941 | 27,983 |
| Facilities | **2** | **5,746** | **5,748** | (31) | 5,751 | 5,720 |
| Exploration and development spending[1] | **437** | **40,850** | **41,287** | 11 | 33,692 | 33,703 |
| Land | **1,474** | **111** | **1,585** | 70 | 1,162 | 1,232 |
| Geological and geophysical ("G&G") | **385** | **—** | **385** | 231 | — | 231 |
| Corporate and other | **—** | **119** | **119** | — | 199 | 199 |
| Total capital expenditures[1] | **2,296** | **41,080** | **43,376** | 312 | 35,053 | 35,365 |

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

| | Nine months ended September 30, | | | | | |
|---|---|---|---|---|---|---|
| | **2026** | | | 2025 | | |
| (*$ thousands*) | **E&E** | **PP&E** | **Total** | E&E | PP&E | Total |
| Drilling and completions | **3,411** | **91,569** | **94,980** | 1,079 | 65,498 | 66,577 |
| Facilities | **699** | **17,949** | **18,648** | 236 | 12,969 | 13,205 |
| Exploration and development spending[1] | **4,110** | **109,518** | **113,628** | 1,315 | 78,467 | 79,782 |
| Land | **4,356** | **255** | **4,611** | 4,169 | 5,940 | 10,109 |
| Geological and geophysical ("G&G") | **737** | **542** | **1,279** | 1,178 | — | 1,178 |
| Corporate and other | **—** | **405** | **405** | — | 396 | 396 |
| Total capital expenditures[1] | **9,203** | **110,720** | **119,923** | 6,662 | 84,803 | 91,465 |

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

***Exploration and Development Spending by cash-generating unit ("CGU")***

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *($ thousands)* | **2026** | 2025 | **2026** | 2025 |
| Eastern Heavy Oil | **40,932** | 27,518 | **106,817** | 72,774 |
| West Central | **355** | 6,185 | **6,811** | 7,008 |
| Exploration and development spending[1] | **41,287** | 33,703 | **113,628** | 79,782 |

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

***Wells drilled by area***

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *(gross/net)* | **2026** | 2025 | **2026** | 2025 |
| **Development** | | | | |
| Figure Lake[1][4] | **8 / 8.0** | 5 / 5.0 | **25 / 25.0** | 14 / 14.0 |
| Frog Lake[2][3][7] | **9 / 7.5** | 7 / 5.5 | **17 / 13.5** | 19 / 14.0 |
| Marten Hills waterflood injection[5] | **-/-** | - / - | **-/-** | 1 / 0.3 |
| Edson | **-/-** | 2 / 1.0 | **2 / 1.0** | 2 / 1.0 |
| **Exploration** | | | | |
| Other exploratory[6] | **- / -** | - / - | **1 / 1.0** | 1 / 1.0 |
| **Total** | **17 / 15.5** | 14 / 11.5 | **45 / 40.5** | 37 / 30.3 |

(1) 1 (1.0 net) well drilled at Figure Lake was spud at the end of September 2026 and rig released in October 2026 and not included in the Q3 2026 well count.
(2) 1 (1.0 net) GP well drilled at Frog Lake was spud at the end of September 2026 and rig released in October 2026 and not included in the Q3 2026 well count.
(3) 1 (1.0 net) well drilled at Frog Lake was junked and abandoned during Q3 2026.
(4) 4 (4.0 net) wells drilled in H1 2026 at Figure Lake were the enhanced oil recovery pilot 8-leg producers and single-leg injector pairs on the 8-26 Pad.
(5) 1 (0.3 net) injection waterflood well was drilled at Marten Hills on the 12-35 Pad during Q1 2025.
(6) 1 (1.0 net) horizontal evaluation well was drilled in Q1 2026 and the costs remain in E&E on the balance sheet. 1 (1.0 net) evaluation well was drilled in Q1 2025 and the costs associated were transferred to E&E expense in Q1 2025.
(7) Six wells drilled in Q3 2026 were at 100% working interest. FLERC has the option on wells drilled in Frog Lake to elect for a 50% working interest in the well or alternatively earn a gross overriding royalty. As at November 6, 2026, FLERC's elections on two of these wells, and on one GP well rig released in October 2026, remain outstanding and the wells are reported at 100% working interest, with total net spending of $4.1 million, pending those elections.

***Capital Expenditures***

During the third quarter of 2026, the Company spent $41.3 million on exploration and development activities, before land, geological and geophysical, corporate and other spending (Q3 2025 - $33.7 million). Capital activities in the third quarter included the following:

At Figure Lake, the Company drilled 8 (8.0 net) wells and completed and brought onto sales production 10 (10.0 net) wells.

- Drilled and completed 8 (8.0 net) OHML wells on the 12-28 Pad, the 14-22 Pad and the 13-26 Pad targeting development of the Clearwater formation using the Company's standard 15,000m primary well design;
- A portion of capital to drill 1 (1.0 net) additional well on the 13-26 Pad was spent during the third quarter and was rig released early in the fourth quarter of 2026;
- Lease construction spending included $1.1 million to apply soil cement to stabilize existing pad sites to reduce weather-related downtime and maintenance costs, and $1.8 million of incremental road and lease costs resulting from extreme wet weather; and
- Facilities spending included $1.9 million on new pad sites, a pipeline reactivation and field modifications related to several enhanced oil recovery pilot projects.

At Frog Lake, the Company drilled 9 (7.5 net) wells and completed and brought on production 8 (5.5 net) wells.

- Drilled and completed 3 (2.5 net) OHML wells targeting the development of the Waseca South formation;
- Drilled and completed 3 (2.5 net) single leg lined circulation string wells ("SLLC") targeting the Sparky formation, and 1 (1.0 net) well that was junked and abandoned during the drilling process in the quarter;
- Drilled and completed 2 (1.5 net) wells targeting the GP formation;
- A portion of capital to drill 1 (1.0 net) additional GP well on the 4-22 Pad was spent during the third quarter and was rig released early in the fourth quarter of 2026; and
- Facilities spending included $3.4 million on new pad sites.

During the first nine months of 2026, the Company spent $113.6 million on exploration and development activities, before land and other corporate spending, primarily related to the drill, complete, equip and tie-in of the following:

- 21 (21.0 net) multi-lateral horizontal wells at Figure Lake;
- 2 (2.0 net) enhanced oil recovery pilot producers and 2 (2.0 net) injector pairs at Figure Lake;
- 5 (3.5 net) Waseca South development wells at Frog Lake;
- 4 (3.5 net) Waseca North development wells at Frog Lake;
- 4 (3.0 net) GP wells at Frog Lake;
- 4 (3.5 net) Sparky wells at Frog Lake, which included 1 (1.0 net) well that was junked and abandoned during the third quarter;
- 2 (1.0 net) Wilrich natural gas development wells at East Edson;
- 1 (1.0 net) exploratory evaluation well in southwest Saskatchewan;
- Lease construction spending at Figure Lake included $1.1 million to apply soil cement on existing pad sites, and $3.0 million of incremental road and lease maintenance costs resulting from extreme wet weather; and
- Facilities spending included $17.9 million on new pad sites, a pipeline reactivation and field modifications related to several enhanced oil recovery pilot projects at Figure Lake.

Land spending totaled $1.6 million in the third quarter of 2026, with total spending of $4.6 million to capture acreage in core areas and for multiple exploration prospects (Q3 2025 - $1.2 million; 2025 - $10.1 million). Geological and geophysical spending totaled $0.4 million in the third quarter of 2026, with total spending of $1.3 million in the first nine months of 2026 (Q3 2025 - $0.2 million; 2025 - $1.2 million), primarily related to core testing to inform enhanced oil recovery pilot work and various seismic data purchases.

Rubellite spent $0.2 million (Q3 2025 - $0.4 million) on abandonment and reclamation projects, with total asset retirement obligation expenditures of $0.7 million (2025 - $1.3 million) in the first nine months of 2026. There was one reclamation certificate received from the AER in the third quarter of 2026 and an additional two reclamation certificates early in the fourth quarter, bringing the total to six certificates as of November 6, 2026 (Q3 2025 - nil; 2025 - two certificates).

**Sales Production**

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | **2026** | 2025 | **2026** | 2025 |
| Sales volumes | | | | |
| Heavy oil (bbl/d) | **8,542** | 8,338 | **8,572** | 8,438 |
| Natural gas (Mcf/d) | **19,641** | 20,975 | **24,884** | 21,174 |
| NGL (bbl/d) | **312** | 288 | **400** | 342 |
| Total sales volumes (boe/d) | **12,128** | 12,122 | **13,119** | 12,309 |

Sales production for the three and nine months ended September 30, 2026 by CGU:

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | **2026** | 2025 | **2026** | 2025 |
| Sales volumes by CGU | | | | |
| Eastern Heavy Oil (boe/d) | **9,505** | 8,831 | **9,550** | 8,888 |
| West Central (boe/d) | **2,623** | 3,291 | **3,569** | 3,421 |
| Total sales volumes (boe/d) | **12,128** | 12,122 | **13,119** | 12,309 |

Total sales production for the three and nine months ended September 30, 2026, increased by 6 boe/d and 810 boe/d from the comparative periods of 2025. Third quarter sales production reflected the East Edson Disposition in West Central Alberta which closed September 8, 2026 and variable well performance results from the third quarter heavy oil drilling program, partially offset by increased solution gas conservation at the Figure Lake gas plant. The increase for the first nine months of 2026 was driven by the Company's heavy oil drilling program, East Edson natural gas production prior to the disposition and increased solution gas conservation at Figure Lake.

Heavy oil sales production averaged 8,542 bbl/d and 8,572 bbl/d for the three and nine months ended September 30, 2026, an increase of 2% from the comparative periods of 2025 (Q3 2025 - 8,338 bbl/d; 2025 - 8,438 bbl/d). During the third quarter of 2026, 18 (15.5 net) heavy oil wells were added to sales, with initial production rates varying across the program and included a number of Tier 2 locations (see "Operations Update"), which, combined with natural declines from base production, limited growth in the quarter. At the end of the third quarter, an additional 4 (4.0 net) wells were awaiting tie-ins, or recovery of drilling fluids and not yet contributing to sales.

Natural gas production averaged 19.6 MMcf/d for the three months ended September 30, 2026, a decrease of 6% from the comparative period (Q3 2025 - 21.0 MMcf/d) as a result of the East Edson Disposition. East Edson contributed 2,623 boe/d to third quarter sales production (Q3 2025 - 3,291 boe/d), averaging approximately 3,460 boe/d over the 69 days prior to the disposition. The decrease was partially offset by increased solution gas conservation at Figure Lake, where the gas plant contributed an average of 5.7 MMcf/d of solution gas sales during the third quarter of 2026, compared to 2.9 MMcf/d in the third quarter of 2025.

Natural gas production averaged 24.9 MMcf/d for the nine months ended September 30, 2026, an increase of 18% from the comparative period of 2025 (2025 - 21.2 MMcf/d). In the West Central area, 2 (1.0 net) liquids-rich natural gas wells were brought on production at the end of the fourth quarter of 2025, followed by 2 (1.0 net) additional wells during the first quarter of 2026. In addition, the Figure Lake gas plant contributed an average of 5.8 MMcf/d of solution gas sales as compared to 2.7 MMcf/d of solution gas sales in the comparative period of 2025.

During the three and nine months ended September 30, 2026, NGL production averaged 312 bbl/d and 400 bbl/d, an 8% and 17% increase from the comparative periods of 2025.

Rubellite's sales product mix, based on sales production, averaged 73% heavy oil and NGL and 27% natural gas during the third quarter (Q3 2025 - 71% heavy oil and NGL and 29% natural gas). The first nine months of 2026 sales production mix averaged 68% heavy oil and NGL and 32% natural gas (2025 comparative periods - 71% and 29%). The product mix for 2026 reflects increased solution gas conservation at Figure Lake and East Edson production prior to the disposition. Following the disposition, Rubellite's sales production is weighted approximately 90% to heavy oil.

**Revenue**

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *($ thousands, except as noted)* | **2026** | 2025 | **2026** | 2025 |
| Oil and natural gas revenue | | | | |
| Oil | **76,710** | 55,536 | **213,157** | 170,599 |
| Natural gas | **2,967** | 1,268 | **12,987** | 9,156 |
| NGL | **2,006** | 1,486 | **7,845** | 5,684 |
| Oil and natural gas revenue | **81,683** | 58,290 | **233,989** | 185,439 |
| | | | | |
| Reference prices | | | | |
| West Texas Intermediate (WTI) (US$/bbl) | **85.79** | 64.93 | **83.50** | 66.70 |
| Foreign Exchange rate (CAD$/US$) | **1.40** | 1.38 | **1.38** | 1.40 |
| WTI (CAD$/bbl) | **120.00** | 89.60 | **115.62** | 93.38 |
| Western Canadian Select (WCS) differential (US$/bbl) | **(13.89)** | (10.39) | **(14.24)** | (11.11) |
| WCS (CAD$/bbl) | **100.56** | 75.10 | **95.92** | 77.88 |
| Heavy oil wellhead differential (CAD$/bbl)[3] | **2.94** | 2.70 | **4.83** | 3.82 |
| AECO 5A Daily Index (CAD$/GJ) | **1.48** | 0.60 | **1.64** | 1.42 |
| AECO 5A Daily Index (CAD$/Mcf)[1] | **1.56** | 0.63 | **1.73** | 1.50 |
| Rubellite average realized prices[2][3] | | | | |
| Oil ($/bbl) | **97.62** | 72.40 | **91.09** | 74.06 |
| Natural gas ($/Mcf) | **1.64** | 0.66 | **1.91** | 1.58 |
| NGL ($/bbl) | **69.83** | 56.12 | **71.83** | 60.85 |
| Average realized price ($/boe)[2][3] | **73.21** | 52.27 | **65.33** | 55.18 |

(1) Converted from $/GJ using a standard energy conversion rate of 1.06 GJ:1 Mcf.
(2) Average prices are presented before risk management contracts;
(3) Supplementary financial measure. See "Non-GAAP and Other Financial Measures".

Rubellite's oil and natural gas revenue for the three and nine months ended September 30, 2026 increased by $23.4 million, or 40%, and $48.6 million, or 26%, from the comparative periods of 2025, primarily driven by higher realized oil prices.

Oil revenue for the third quarter of 2026 was $76.7 million, representing 94% of total revenue, while heavy oil production was 70% of total sales volumes. The 38% increase in oil revenue was driven by a 35% increase in average realized oil prices and a 2% increase in heavy oil sales volumes. The WCS price averaged $100.56/bbl in the third quarter (Q3 2025 - $75.10/bbl), reflecting higher WTI oil prices of US$85.79/bbl (Q3 2025 - US$64.93/bbl), partially offset by the widening of the WCS differential to US$13.89/bbl (Q3 2025 - US$10.39/bbl). Rubellite's heavy oil wellhead differential, which reflects a price offset for quality, diluent blending costs and optimization of sales delivery points, averaged $2.94/bbl during the third quarter of 2026 (Q3 2025 - $2.70/bbl).

During the first nine months of 2026, oil revenue was $213.2 million and represented 91% of total revenue while heavy oil production was 65% of total sales volumes. The 25% increase in oil revenue was driven by a 23% increase in average realized oil prices and a 2% increase in heavy oil sales volumes. Higher WCS prices were driven by an increase in WTI oil prices to US$83.50/bbl (2025 - US$66.70/bbl), partially offset by a decrease in the CAD$/US$ rate to $1.38 (2025 - $1.40) and the widening of the WCS differential to US$14.24/bbl (2025 - US$11.11/bbl). Rubellite's heavy oil wellhead differential averaged $4.83/bbl for the first nine months of 2026, higher than the comparative period of 2025 of $3.82/bbl due to higher diluent costs in the first half of 2026.

Natural gas revenue in the third quarter of 2026 was $3.0 million, representing 4% of total revenue, while natural gas production accounted for 27% of total sales volumes. The $1.7 million increase in natural gas revenue was driven by higher average realized natural gas prices of $1.64/Mcf (Q3 2025 - $0.66/Mcf), partially offset by a 6% decrease in natural gas sales volumes following the disposition of the East Edson

assets. For the nine months ended September 30, 2026, natural gas revenue was $13.0 million and 6% of total revenue while natural gas production was 32% of total sales volumes. The 42% increase in natural gas revenue was driven by a 18% increase in natural gas sales volumes and a 21% increase in average realized natural gas prices.

NGL revenue was $2.0 million in the third quarter of 2026, representing 2% of total revenue and 3% of total sales volumes. The 35% increase in NGL revenue was driven by a 24% increase in average realized NGL prices and an 8% increase in NGL sales volumes. For the nine months ended September 30, 2026, NGL revenue of $7.8 million represented 3% of total revenue and 3% of total sales volumes. The 38% increase in NGL revenue was driven by a 17% increase in NGL sales volumes and an 18% increase in average realized NGL prices.

**Risk Management Contracts**

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

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

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| (*$ thousands, except as noted*) | **2026** | 2025 | **2026** | 2025 |
| Unrealized gain (loss) on risk management contracts | | | | |
| Unrealized gain (loss) on oil contracts[1] | **(43,421)** | (5,446) | **(37,236)** | 2,186 |
| Unrealized gain (loss) on natural gas contracts | **(263)** | (1,998) | **5** | (5,218) |
| Unrealized loss on risk management contracts | **(43,684)** | (7,444) | **(37,231)** | (3,032) |
| Realized gain (loss) on risk management contracts | | | | |
| Realized gain (loss) on oil contracts[1] | **(11,390)** | 1,817 | **(31,500)** | 2,734 |
| Realized gain on natural gas contracts | **714** | 2,149 | **1,638** | 5,867 |
| Realized gain (loss) on risk management contracts | **(10,676)** | 3,966 | **(29,862)** | 8,601 |

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

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

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | **2026** | 2025 | **2026** | 2025 |
| Realized gain (loss) on risk management contracts | | | | |
| Realized gain (loss) on oil contracts ($/bbl)[1] | **(14.49)** | 2.37 | **(13.46)** | 1.19 |
| Realized gain on natural gas contracts ($/Mcf) | **0.40** | 1.11 | **0.24** | 1.01 |
| Realized gain (loss) on risk management contracts ($/boe) | **(9.57)** | 3.56 | **(8.34)** | 2.56 |
| Average realized prices after risk management contracts[2] | | | | |
| Oil ($/bbl) | **83.13** | 74.77 | **77.63** | 75.25 |
| Natural gas ($/Mcf) | **2.04** | 1.77 | **2.15** | 2.59 |
| NGL ($/bbl) | **69.83** | 56.12 | **71.83** | 60.85 |
| Average realized price ($/boe)[2] | **63.64** | 55.83 | **56.99** | 57.74 |

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

The realized loss on risk management contracts was $10.7 million, or $9.57/boe, for the third quarter of 2026 (Q3 2025 - realized gain of $4.0 million, or $3.56/boe). For the nine month period ending September 30, 2026, the realized loss on risk management contracts totaled $29.9 million or $8.34/boe (2025 - realized gain of $8.6 million or $2.56/boe). Realized gains or losses reflect fluctuations relative to pricing on commodity contracts driven by changes in AECO, WTI and WCS differential benchmark prices as well as fluctuations in foreign exchange rates and the percentage of production volumes hedged.

The unrealized loss on risk management contracts was $43.7 million in the third quarter of 2026 (Q3 2025 – $7.4 million unrealized loss) and the unrealized loss on risk management contracts was $37.2 million for the nine month period ended September 30, 2026 (2025 - $3.0 million unrealized loss). Unrealized gains and losses reflect the period end change in the mark-to-market value of risk management contracts, driven by movements in forward commodity prices and foreign exchange rates. 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 September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| (*$ thousands, except as noted*) | **2026** | 2025 | **2026** | 2025 |
| Royalty expenses | **13,606** | 8,003 | **35,199** | 25,083 |
| *$/boe* | **12.19** | 7.18 | **9.83** | 7.46 |
| Royalties *(% of revenue)*[1] | **16.7** | 13.7 | **15.0** | 13.5 |

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

Royalties payable by the Company include Crown royalties payable to provincial governments, royalties payable to Indian Oil and Gas Canada ("IOGC") and freehold and gross overriding royalties ("GORR"). The relative mix between Crown, IOGC, freehold and GORR production as a percentage of total production can change the composition of royalties from one period to the next. Under the Alberta Modernized Royalty

Framework ("MRF") and the Indian Oil and Gas Act, Crown and IOGC royalties range from 5% to 40% on wells where mineral rights are leased from either the Crown or through IOGC. The remainder of royalties relate to freehold and GORR interests. All royalty rates paid by the Company are price sensitive and fluctuate with commodity pricing.

Total royalties for the three and nine months ended September 30, 2026 were $13.6 million and $35.2 million, an increase from the comparative periods of 2025, reflecting higher oil and NGL prices and, for the nine-month period, higher total sales volumes. During the second quarter of 2026, the Company received its annual gas cost allowance ("GCA") adjustment, which was a payable of $0.2 million (2025 - $1.0 million credit).

On a per boe basis, royalties were $12.19/boe and $9.83/boe, an increase from the comparative periods of 2025, driven by higher prices. Royalties as a percentage of revenue were higher than the comparative periods of 2025 due to an increased number of wells receiving higher royalty rates as a result of significantly higher prices. Specifically, oil royalty reference par prices have been higher during the year and trail actual prices by two months in arrears.

**Net operating costs[(1)]**

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| (*$ thousands, except as noted*) | **2026** | 2025 | **2026** | 2025 |
| Net operating costs[(1)] | **10,344** | 7,206 | **27,628** | 22,593 |
| *$/boe* | **9.27** | 6.46 | **7.71** | 6.72 |

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

Total net operating costs for the three and nine months ended September 30, 2026 increased to $10.3 million and $27.6 million from $7.2 million and $22.6 million in the comparative periods of 2025. The increase was driven by higher road maintenance, trucking and well servicing costs at the heavy oil properties due to extremely wet conditions in the field that occurred during the second quarter and persisted into the third quarter. This was partially offset by the removal of East Edson operating costs, following the East Edson Disposition.

On a per boe basis, net operating costs increased by 43% to $9.27/boe in the third quarter of 2026 (Q3 2025 - $6.46/boe), reflecting the disposition of the low cost East Edson property during the quarter along with higher costs from extremely wet road and lease conditions in the field. West Central sales production carries significantly lower net operating costs per boe than the Eastern Heavy Oil properties ($3.89/boe compared to $10.76/boe in the third quarter of 2026). For the nine months ended September 30, 2026, net operating costs on a per boe basis increased 15% to $7.71/boe (2025 - $6.72/boe), driven by the weather-related cost increases in the second and third quarters and, to a lesser extent, the East Edson Disposition. Following the disposition, net operating costs on a per boe basis are expected to reflect the higher cost structure of the Company's heavy oil properties.

**Transportation costs**

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| (*$ thousands, except as noted*) | **2026** | 2025 | **2026** | 2025 |
| Oil and NGL transportation costs | **6,022** | 4,509 | **16,964** | 16,216 |
| Natural gas transportation costs | **540** | 692 | **2,030** | 1,923 |
| Total transportation costs | **6,562** | 5,201 | **18,994** | 18,139 |
| *$/boe* | **5.88** | 4.66 | **5.30** | 5.40 |

Transportation costs include clean oil trucking, NGL transportation and natural gas transportation from plant gate to commercial sales points.

Transportation costs for the three and nine months ended September 30, 2026 increased to $6.6 million and $19.0 million from $5.2 million and $18.1 million in the comparative periods of 2025. Oil and NGL transportation costs increased to $6.0 million in the third quarter of 2026 (Q3 2025 - $4.5 million), reflecting higher trucking costs due to poor road conditions, higher fuel surcharges and diesel prices, and the 2% increase in heavy oil sales production. Natural gas transportation costs decreased in the third quarter of 2026, reflecting lower natural gas sales volumes following the East Edson Disposition. For the first nine months of 2026, the increase in transportation costs reflects higher fuel surcharges and weather-related trucking costs, and higher natural gas sales volumes prior to the disposition, partially offset by lower overall trucking rates negotiated at Rubellite's heavy oil properties.

On a per boe basis, transportation costs were $5.88/boe in the third quarter of 2026, a 26% increase from the comparative period (Q3 2025 - $4.66/boe). In addition to the higher trucking costs noted above, the increase reflects a shift in the Company's production mix following the East Edson Disposition. East Edson's pipeline-connected natural gas production incurred significantly lower transportation costs per boe than the Company's trucked heavy oil production. For the first nine months of 2026, transportation costs were $5.30/boe, 2% lower than the comparative period of 2025 (2025 - $5.40/boe) as improved trucking rates and fixed natural gas transportation commitments allocated over higher sales volumes more than offset increased trucking costs from poor road conditions and higher fuel surcharges.

**Operating netbacks**

The following tables highlight Rubellite's operating netbacks for the three and nine months ended September 30, 2026 and 2025**:**

| | Three months ended September 30, 2026 | | | Three months ended September 30, 2025 | | |
|---|---|---|---|---|---|---|
| *($ thousands)* | **Eastern Heavy Oil** | **West Central** | **Total** | Eastern Heavy Oil | West Central | Total |
| Revenue | **77,635** | **4,048** | **81,683** | 55,774 | 2,516 | 58,290 |
| Royalties | **(12,809)** | **(797)** | **(13,606)** | (7,219) | (784) | (8,003) |
| Net operating costs[1] | **(9,406)** | **(938)** | **(10,344)** | (5,406) | (1,800) | (7,206) |
| Transportation costs | **(6,119)** | **(443)** | **(6,562)** | (4,529) | (672) | (5,201) |
| Operating netback[1] | **49,301** | **1,870** | **51,171** | 38,620 | (740) | 37,880 |
| Realized gain (loss) on risk management contracts[2] | **—** | **—** | **(10,676)** | — | — | 3,966 |
| Total operating netback, after risk management contracts[1] | **49,301** | **1,870** | **40,495** | 38,620 | (740) | 41,846 |

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized loss on risk management contracts in the third quarter of 2026 included a $11.4 million loss on oil contracts and $0.7 million gain on gas contracts (Q3 2025 - $1.8 million gain on oil contracts and $2.1 million gain on gas contracts).

| | Nine months ended September 30, 2026 | | | Nine months ended September 30, 2025 | | |
|---|---|---|---|---|---|---|
| *($ thousands)* | **Eastern Heavy Oil** | **West Central** | **Total** | Eastern Heavy Oil | West Central | Total |
| Revenue | **216,291** | **17,698** | **233,989** | 171,819 | 13,620 | 185,439 |
| Royalties | **(32,194)** | **(3,005)** | **(35,199)** | (23,008) | (2,075) | (25,083) |
| Net operating costs[1] | **(24,371)** | **(3,257)** | **(27,628)** | (17,192) | (5,401) | (22,593) |
| Transportation costs | **(17,234)** | **(1,760)** | **(18,994)** | (16,298) | (1,841) | (18,139) |
| Operating netback[1] | **142,492** | **9,676** | **152,168** | 115,321 | 4,303 | 119,624 |
| Realized gain (loss) on risk management contracts[2] | **—** | **—** | **(29,862)** | — | — | 8,601 |
| Total operating netback, after risk management contracts[1] | **142,492** | **9,676** | **122,306** | 115,321 | 4,303 | 128,225 |

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized loss on risk management contracts in the first nine months of 2026 included a $31.5 million loss on oil contracts and $1.6 million gain on gas contracts (2025 - $2.7 million gain on oil contracts and $5.9 million gain on gas contracts).

| | Three months ended September 30, 2026 | | | Three months ended September 30, 2025 | | |
|---|---|---|---|---|---|---|
| *($/boe)* | **Eastern Heavy Oil** | **West Central** | **Total** | Eastern Heavy Oil | West Central | Total |
| Revenue | **88.79** | **16.77** | **73.21** | 68.65 | 8.31 | 52.27 |
| Royalties | **(14.65)** | **(3.30)** | **(12.19)** | (8.89) | (2.59) | (7.18) |
| Net operating costs[1] | **(10.76)** | **(3.89)** | **(9.27)** | (6.65) | (5.94) | (6.46) |
| Transportation costs | **(7.00)** | **(1.84)** | **(5.88)** | (5.57) | (2.22) | (4.66) |
| Operating netback[1] | **56.38** | **7.74** | **45.87** | 47.54 | (2.44) | 33.97 |
| Realized gain (loss) on risk management contracts[2] | **—** | **—** | **(9.57)** | — | — | 3.56 |
| Total operating netback, after risk management contracts[1] | **56.38** | **7.74** | **36.30** | 47.54 | (2.44) | 37.53 |

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized loss on risk management contracts in the third quarter of 2026 included a $14.49/bbl loss on oil contracts and a $0.40/Mcf gain on gas contracts (Q3 2025 - $2.37/bbl gain on oil contracts and $1.11/Mcf gain on gas contracts).

| | Nine months ended September 30, 2026 | | | Nine months ended September 30, 2025 | | |
|---|---|---|---|---|---|---|
| *($/boe)* | **Eastern Heavy Oil** | **West Central** | **Total** | Eastern Heavy Oil | West Central | Total |
| Revenue | **82.95** | **18.17** | **65.33** | 70.81 | 14.58 | 55.18 |
| Royalties | **(12.35)** | **(3.08)** | **(9.83)** | (9.48) | (2.22) | (7.46) |
| Net operating costs[1] | **(9.35)** | **(3.34)** | **(7.71)** | (6.94) | (5.78) | (6.72) |
| Transportation costs | **(6.61)** | **(1.81)** | **(5.30)** | (6.72) | (1.97) | (5.40) |
| Operating netback[1] | **54.64** | **9.94** | **42.49** | 47.67 | 4.61 | 35.60 |
| Realized gain (loss) on risk management contracts[2] | **—** | **—** | **(8.34)** | — | — | 2.56 |
| Total operating netback, after risk management contracts[1] | **54.64** | **9.94** | **34.15** | 47.67 | 4.61 | 38.16 |

(1) Non-GAAP measure. See "Non-GAAP and Other Financial Measures".
(2) Realized hedging for the first nine months of 2026 included a $13.46/bbl loss on oil contracts and a $0.24/Mcf gain on gas contracts (2025 - $1.19/bbl gain on oil contracts and $1.01/Mcf gain on gas contracts).

Rubellite's Eastern Heavy Oil operating netback for the three and nine months ended September 30, 2026 increased to $49.3 million and $142.5 million (Q3 2025 - $38.6 million; 2025 - $115.3 million) primarily as a result of higher realized oil prices, partially offset by higher royalties and net operating costs. On a per boe basis, the operating netback increased to $56.38/boe and $54.64/boe (Q3 2025 - $47.54/boe; 2025 - $47.67/boe), reflecting higher realized prices, partially offset by higher royalties, net operating costs and, in the third quarter, transportation costs. Net operating and transportation costs in the third quarter of 2026 continued to be impacted by higher road maintenance, trucking and well servicing costs due to extremely wet field conditions and higher fuel surcharges.

Rubellite's West Central operating netback for the three and nine months ended September 30, 2026 increased to $1.9 million and $9.7 million (Q3 2025 - operating netback loss of $0.7 million; 2025 - $4.3 million). The third quarter increase was driven by higher realized natural gas and NGL prices and lower net operating costs, partially offset by lower sales volumes following the East Edson Disposition. The nine month increase was driven by higher realized natural gas and NGL prices and lower net operating costs, higher sales volumes from wells brought on production in the fourth quarter of 2025 and first quarter of 2026. On a per boe basis, the West Central operating netback increased to $7.74/boe and $9.94/boe (Q3 2025 - operating netback loss of $2.44/boe; 2025 - operating netback of $4.61/boe), reflecting higher realized prices and lower net operating and transportation costs, partially offset by higher royalties.

Rubellite's total operating netback for the three and nine months ended September 30, 2026 increased to $51.2 million and $152.2 million from $37.9 million and $119.6 million in the comparative periods of 2025. In the third quarter, the increase reflects higher realized oil and NGL prices and a higher weighting of heavy oil in the Company's production mix following the East Edson Disposition, partially offset by higher royalties, net operating costs and transportation costs. For the first nine months of 2026, the increase reflects higher total sales volumes, higher total prices, partially offset by higher royalties, net operating costs and transportation costs. On a per boe basis, the total operating netback increased to $45.87/boe and $42.49/boe for the three and nine months ended September 30, 2026 (Q3 2025 – $33.97/boe; 2025 – $35.60/boe), as higher realized prices more than offset higher royalties and net operating costs and, in the third quarter, higher transportation costs.

For the three and nine months ended September 30, 2026, the operating netback after realized losses on risk management contracts of $9.57/boe and $8.34/boe, was $36.30/boe and $34.15/boe (Q3 2025 – $37.53/boe; 2025 - $38.16/boe; after realized gains on risk management contracts).

**General and administrative ("G&A") expenses**

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| (*$ thousands, except as noted*) | **2026** | 2025 | **2026** | 2025 |
| G&A expenses – before recoveries | **5,386** | 5,220 | **16,873** | 15,947 |
| G&A recoveries | **(2,714)** | (1,605) | **(5,920)** | (3,903) |
| Total G&A expenses | **2,672** | 3,615 | **10,953** | 12,044 |
| *$/boe* | **2.39** | 3.24 | **3.06** | 3.58 |

Before overhead recoveries, G&A expenses for the three and nine months ended September 30, 2026 increased to $5.4 million and $16.9 million (Q3 2025 – $5.2 million; 2025 - $15.9 million), primarily due to higher people-related costs. Total G&A expenses, net of recoveries, decreased to $2.7 million and $11.0 million (Q3 2025 - $3.6 million; 2025 - $12.0 million), as higher overhead recoveries related to increased exploration and development capital spending more than offset the increase in gross costs. Overhead recoveries vary from period to period based on the amount of exploration and development capital spending.

On a per boe basis, G&A costs for the three and nine months ended September 30, 2026 decreased to $2.39/boe and $3.06/boe (Q3 2025 - $3.24/boe; 2025 - $3.58/boe), reflecting higher overhead recoveries on increased exploration and development capital spending and, for the nine-month period, higher total sales volumes relative to the comparative period of 2025.

**Depletion**

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| (*$ thousands, except as noted*) | **2026** | 2025 | **2026** | 2025 |
| Depletion | **24,182** | 23,093 | **73,268** | 68,420 |
| Depreciation | **556** | 521 | **1,650** | 1,530 |
| Total depletion and depreciation | **24,738** | 23,614 | **74,918** | 69,950 |
| *($/boe)* | | | | |
| Depletion | **21.67** | 20.71 | **20.46** | 20.36 |
| Depreciation | **0.50** | 0.47 | **0.46** | 0.46 |
| *$/boe* | **22.17** | 21.18 | **20.92** | 20.82 |

The Company calculates depletion using the net book value of the assets, future development costs associated with proved and probable reserves, salvage values on associated production equipment, as well as proved plus probable reserves and sales production. As at September 30, 2026, depletion was calculated on a $483.3 million depletable balance (December 31, 2025 – $514.8 million), $312.0 million in future development costs (December 31, 2025 – $457.6 million) and excluded an estimated $10.5 million of salvage value (December 31, 2025 – $12.4 million).

Depletion and depreciation expense for the third quarter of 2026 was $24.7 million or $22.17/boe (Q3 2025 – $23.6 million or $21.18/boe) and $74.9 million or $20.92/boe for the first nine months of 2026 (2025 - $70.0 million or $20.82/boe). The increase in depletion on a dollar and per boe basis in the third quarter was primarily due to a higher weighting of heavy oil production, which carries a higher depletion rate, following the East Edson Disposition. For the first nine months of 2026, the increase in depletion on a dollar basis was primarily due to higher sales volumes, and on a per boe basis reflects a higher weighting of heavy oil production and higher West Central CGU depletion rates, partially offset by lower Eastern Heavy Oil CGU depletion rates. The decrease in the depletable balance and future development costs reflects the disposition of the East Edson assets on September 8, 2026.

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

**Impairment**

*Eastern Heavy Oil CGU*

The Company assessed its Eastern Heavy Oil CGU for indicators of impairment as at September 30, 2026 and December 31, 2025, and concluded there were no indicators of impairment, therefore an impairment test was not required.

**Finance expense**

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *($ thousands)* | **2026** | 2025 | **2026** | 2025 |
| Cash finance expense | | | | |
| Interest on bank debt | **1,914** | 1,909 | **5,391** | 5,406 |
| Interest on term loan | **580** | 580 | **1,720** | 1,721 |
| Interest on other provision | **140** | — | **284** | — |
| Interest on lease liabilities | **75** | 79 | **226** | 239 |
| Total cash finance expense | **2,709** | 2,568 | **7,621** | 7,366 |
| *$/boe* | **2.43** | 2.30 | **2.13** | 2.19 |
| Non-cash finance expense | | | | |
| Amortization of debt issue costs | **50** | 44 | **143** | 126 |
| Accretion on decommissioning obligations | **336** | 282 | **1,029** | 811 |
| Accretion on other provision | **89** | 114 | **290** | 366 |
| Total non-cash finance expense | **475** | 440 | **1,462** | 1,303 |
| *$/boe* | **0.43** | 0.39 | **0.41** | 0.39 |
| **Finance expense** | **3,184** | 3,008 | **9,083** | 8,669 |

Total cash finance expense for the three and nine months ended September 30, 2026 increased to $2.7 million and $7.6 million (Q3 2025 - $2.6 million; 2025 - $7.4 million) primarily due to interest on the other provision, which began accruing interest on March 28, 2026. The effective aggregate interest rate on the Company's revolving bank line averaged 5.8% and 5.7% (Q3 2025 - 6.2%; 2025 - 6.2%). The interest rate on the principal amount of the term loan remained unchanged at 11.5% and the other provision accrues interest at 4.5%, reflecting the Bank of Canada prime rate.

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

For the three months ended September 30, 2026, cash finance expense on a per boe basis increased due to higher costs on consistent sales volumes. In the first nine months of 2026, cash finance expense on a per boe basis decreased as higher costs were more than offset by higher sales volumes.

**Deferred Income Taxes**

| | December 31, 2025 | Recognized in earnings | Recognized in equity | **September 30, 2026** |
|---|---|---|---|---|
| Deferred tax assets (liabilities): | | | | |
| Property, plant and equipment | $ (38,100) | $ 8,009 | $ — | **$ (30,091)** |
| Decommissioning obligations | 8,198 | (1,301) | — | **6,897** |
| Fair value of derivatives | (1,265) | 8,563 | — | **7,298** |
| Other liabilities | 2,820 | (778) | — | **2,042** |
| Share and debt issue costs | 414 | (35) | (98) | **281** |
| Non-capital losses | 40,313 | 1,813 | — | **42,126** |
| **Deferred tax asset** | $ 12,380 | $ 16,271 | $ (98) | **$ 28,553** |

For the three and nine months ended September 30, 2026, Rubellite recognized deferred income tax recoveries of $20.8 million and $16.3 million respectively (Q3 2025 – expense of $1.8 million; 2025 – expense of $9.5 million) on losses before income tax of $48.0 million and $32.4 million (Q3 2025 – income of $7.4 million; 2025 – income of $32.3 million). The recoveries reflect the tax effect of the losses before income tax, which were primarily due to realized and unrealized losses on risk management contracts. The recoveries also include a $13.0 million deferred tax recovery related to the disposition of the East Edson assets in Q3 2026.

## LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

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

**Capital Management**

| (*$ thousands, except as noted*) | **September 30, 2026** | December 31, 2025 |
|---|---|---|
| Bank debt | **118,034** | 92,583 |
| Term loan (principal) | **20,000** | 20,000 |
| Marketable securities[2] | **(59,731)** | (438) |
| Adjusted working capital deficit[1] | **30,688** | 30,998 |
| Net debt[1] | **108,991** | 143,143 |
| Shares outstanding at end of period (*thousands*) | **94,552** | 93,593 |
| Market price at end of period (*$/share*) | **4.02** | 2.40 |
| Market value of shares[1] | **380,099** | 224,623 |
| Enterprise value[1] | **489,090** | 367,766 |
| Net debt as a percentage of enterprise value[1] | **22%** | 39% |
| Trailing twelve months adjusted funds flow[1][3] | **137,620** | 142,073 |
| Net debt to trailing twelve months adjusted funds flow ratio[1][3] | **0.8** | 1.0 |
| Annualized adjusted funds flow[1][3] | **143,372** | 132,660 |
| Net debt to annualized adjusted funds flow ratio[1][3] | **0.8** | 1.1 |

(1) Non-GAAP measure or ratio. See "Non-GAAP and Other Financial Measures".
(2) Marketable securities of $59.7 million as at September 30, 2026 comprised of 2,083,411 common shares of Topaz ($59.3 million at the period-end closing price of $28.46 per share) and other securities of $0.4 million, previously presented within prepaid expenses and deposits. Comparative figures have been reclassified to conform with the current period presentation.
(3) Calculated using adjusted funds flow before transaction costs. Trailing twelve months adjusted funds flow is the sum of adjusted funds flow, before transaction costs, for the four most recent quarters. Annualized adjusted funds flow is based on Q3 2026 adjusted funds flow, before transaction costs, of $35.8 million (Q4 2025 – $33.2 million), multiplied by four. See "Non-GAAP and Other Financial Measures" for more details.

At September 30, 2026, Rubellite had net debt of $109.0 million, a 24% decrease from $143.1 million at December 31, 2025. The decrease was primarily due to the receipt of marketable securities as consideration for the East Edson Disposition, which were valued at $59.7 million at September 30, 2026. This was partially offset by negative free funds flow of $15.9 million, as capital expenditures, including land and other spending, of $119.9 million exceeded adjusted funds flow after transaction costs of $104.1 million. Net debt was further offset by $9.6 million of payments for other obligations, which included a $3.8 million reduction of the other provision, $0.7 million of decommissioning expenditures, $1.3 million of cash-settled share-based compensation payments, $0.5 million of lease payments, $0.8 million of cash consideration for the asset swap transaction completed at the end of the second quarter and $2.5 million of other obligations.

Rubellite had available liquidity at September 30, 2026 of $40.6 million, comprised of the $160.0 million credit facility borrowing limit, less $118.0 million of bank borrowings and $1.4 million of outstanding letters of credit.

**Bank debt**

During the second quarter of 2026, the Company's first lien credit facility had its borrowing limit increased to $160.0 million (December 31, 2025 - $140.0 million) and was extended with an initial term to May 31, 2027. Following the East Edson Disposition, the credit facility borrowing limit was reconfirmed at $160.0 million. The initial term may be extended for a further twelve months to May 31, 2028 subject to lender approval. If not extended by May 31, 2027, all outstanding advances would be repayable on May 31, 2028. The next semi-annual borrowing base redetermination is scheduled on or before May 31, 2027.

As at September 30, 2026, $118.0 million was drawn against the credit facility (December 31, 2025 - $92.6 million) and $1.4 million (December 31, 2025 - $1.4 million) of letters of credit were issued. Borrowings under the credit facility bear interest at the lenders' prime rate or CORRA rates, plus applicable margins and standby fees. The applicable CORRA margins range between 2.8% and 6.3%. The effective aggregate interest rate on the credit facility at September 30, 2026 was 5.8% per annum. For the period ended September 30, 2026, if interest rates changed by 1% with all other variables held constant, the impact on cash finance expense would be $1.2 million and the impact on net income (loss) and comprehensive income (loss) would be $0.9 million.

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

At September 30, 2026, the credit facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

**Term Loan**

| | | | **September 30, 2026** | | December 31, 2025 | |
|---|---|---|---|---|---|---|
| *($ thousands)* | **Maturity date** | **Interest rate** | **Principal** | **Carrying Amount** | Principal | Carrying amount |
| Term loan | August 2, 2029 | 11.5% | **20,000** | **19,315** | 20,000 | 19,173 |

Rubellite has a $20.0 million senior secured third-lien term loan placed, directly or indirectly, with certain directors, officers and employees, and their affiliates, of Rubellite. The term loan bears interest at 11.5% annually with interest payments to be paid quarterly, matures in five years from the date of issue, and can be repaid by the Company without penalty at any time.

During the three and nine months ended September 30, 2026, Rubellite paid $0.6 million and $1.7 million in cash interest payments to the holders of the term loan (Q3 2025 - $0.6 million; 2025 - $1.7 million).

At September 30, 2026, the term loan was recorded at the present value of future cash flows, net of $0.7 million (December 31, 2025 - $0.8 million) in issue and discount costs which are amortized over the remaining term using a weighted average effective interest rate of 13.0% (December 31, 2025 - 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 September 30, 2026 and December 31, 2025, entities controlled or directed by the Company's Chief Executive Officer ("CEO") hold $18.4 million of the outstanding term loan.

### Equity

At September 30, 2026, there were 94.6 million common shares outstanding, net of 0.1 million shares held in trust for employee compensation programs (December 31, 2025 - 93.6 million common shares outstanding, net of 0.1 million of shares held in trust).

At November 6, 2026, there were 94.6 million common shares outstanding, net of 0.1 million shares held in trust for employee compensation programs.

The following table summarizes information about options, rights and awards outstanding as of the date of this MD&A. It includes awards under the Rubellite Incentive Plan, the cash or trust settled unit award plan (the "CTU Plan"), and under plans acquired through a business combination (the "Acquired Plans") with Perpetual Energy Inc. ("Perpetual") in the fourth quarter of 2024 (the "Recombination Transaction"):

| *(thousands)* | **November 6, 2026** |
|---|---|
| Restricted share units | 2,333 |
| Cash or trust settled units | 525 |
| Share options | 2,553 |
| Performance share units | 2,454 |
| Perpetual awards[1] | 1,319 |
| **Total[2]** | **9,184** |

(1) Of the 1.3 million share based awards under the Acquired Plans outstanding, 0.8 million awards may be settled for cash or from shares in the employee trust as opposed to treasury issuance.
(2) Of the 7.9 million share based awards outstanding under the Rubellite Incentive Plan and CTU Plan, 5.3 million awards (comprised of RSUs, PSUs and CTUs) may be settled for cash or shares purchased in the open market, including shares held in trust, as opposed to treasury issuance. CTUs may only be settled in cash or from shares held in trust and cannot be settled through treasury issuance.

### Commodity price risk management

As at November 6, 2026, Rubellite had the following oil commodity risk management contracts:

| Commodity | Volumes Sold (bbl/d) | Term | Reference/Index | Contract Traded Bought/Sold | Average Price ($/bbl) |
|---|---|---|---|---|---|
| Crude Oil | 5,400 bbl/d | Oct 2026 - Dec 2026 | WTI (US$/bbl) | Swap - sold | $68.98 |
| Crude Oil | 4,350 bbl/d | Jan 2027 - Dec 2027 | WTI (US$/bbl) | Swap - sold | $71.31 |
| Crude Oil | 1,700 bbl/d | Jan 2028 - Dec 2028 | WTI (US$/bbl) | Swap - sold | $70.03 |
| Crude Oil | 3,000 bbl/d | Oct 2026 - Dec 2026 | WCS Differential (US$/bbl) | Swap - sold | ($13.18) |

### Foreign exchange risk management

As at November 6, 2026, Rubellite had the following foreign exchange risk management contracts:

| Fixed Contract | Notional amount | Term | Price (CAD$/US$) |
|---|---|---|---|
| Average rate forward (CAD$/US$) | $2,500,000 US$/month | Jul - Dec 2026 | 1.4066 |
| Average rate forward (CAD$/US$)[1] | $5,000,000 US$/month | Jul - Dec 2026 | 1.3890 |
| Average rate forward (CAD$/US$) | $500,000 US$/month | Jul - Dec 2026 | 1.4085 |
| Average rate forward (CAD$/US$) | $500,000 US$/month | Oct - Dec 2026 | 1.4100 |
| Average rate forward (CAD$/US$) | $3,000,000 US$/month | Jan -Dec 2027 | 1.3700 |
| Average rate forward (CAD$/US$) | $2,000,000 US$/month | Jan -Dec 2028 | 1.3700 |

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

| Variable Contract | Notional amount | Term | Floor Price (CAD$/US$) | Ceiling Price (CAD$/US$) | Reset Price (CAD$/US$) |
|---|---|---|---|---|---|
| Knock-in Collar (CAD$/US$)[1] | $3,000,000 US$/month | Jan - Dec 2027 | 1.4000 | 1.4400 | 1.4200 |

(1) During the third quarter of 2026, the spot price traded at or below the 1.3810 CAD$/US$ barrier. As a result, Rubellite will not knock into the $3.0 million US$/month contract at 1.4000 CAD$/US$ for the 2028 calendar year.

## COMMITMENTS AND CONTRACTUAL OBLIGATIONS

The Company has a drilling commitment on certain GORR lands that must be fulfilled by December 31, 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 September 30, 2026, the Company spud 55 (55.0 net) of the 59 (59.0 net) wells that are required to meet the drilling commitment. Subsequent to September 30, 2026, the Company spud an additional 2 (2.0 net) wells bringing the total to 57 (57.0 net) of the 59 (59.0 net) wells required to meet the drilling commitment.

## PROVISIONS

### Decommissioning obligations

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

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

| *($ thousands)* | **September 30, 2026** | December 31, 2025 |
|---|---|---|
| Decommissioning obligations – current | **1,340** | 1,340 |
| Decommissioning obligations – non-current | **28,647** | 34,302 |
| **Total decommissioning obligations** | **29,987** | 35,642 |

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

| (*$ thousands, except as noted*) | **September 30, 2026** | December 31, 2025 |
|---|---|---|
| Undiscounted obligations | **41,737** | 49,432 |
| Average risk-free rate | **4.3%** | 3.9% |
| Inflation rate | **2.3%** | 2.0% |
| Expected timing of settling obligations | **1 to 25 years** | 1 to 25 years |

**Other provision**

| *($ thousands)* | **September 30, 2026** | December 31, 2025 |
|---|---|---|
| Other provision – current | **3,750** | 3,750 |
| Other provision – non-current | **8,378** | 11,554 |
| **Total other provision[(1)(2)]** | **12,128** | 15,304 |

(1) The other provision was assumed through the Recombination Transaction and relates to a settlement agreement 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.
(2) The other provision is a second-lien obligation of the Company.

The following assumptions were used to estimate the other provision:

| (*$ thousands, except as noted*) | **September 30, 2026** | December 31, 2025 |
|---|---|---|
| Undiscounted obligations | **12,441** | 16,191 |
| Average risk-free rate | **3.0%** | 3.0% |
| Expected timing of settling obligations | **3.5 years** | 4.3 years |

The Company is required to make annual payments of $3.75 million until the principal of the other provision is fully repaid. Annual scheduled payments were made on March 28, 2026 and March 28, 2025. As of March 28, 2026, interest accrues on the outstanding principal and is payable annually at an interest rate equal to the applicable Bank of Canada prime rate on the date of payment, with the remainder of the annual payment applied to the outstanding principal. The Company is able to pre-pay all, or any portion, of the outstanding principal at any time without bonus or penalty.

## MARKETABLE SECURITIES

| | **September 30, 2026** | December 31, 2025 |
|---|---|---|
| Balance, beginning of period | **$ 438** | $ 350 |
| Acquisition[(1)] | **66,065** | — |
| Change in fair value | **(6,772)** | 88 |
| **Balance, end of period[(2)]** | **$ 59,731** | $ 438 |

(1) Effective September 8, 2026, the Company disposed of its conventional natural gas assets comprising all of the assets of the West Central CGU in exchange for share consideration consisting of 2,083,411 shares of Topaz.
(2) In 2025, marketable securities were disclosed within prepaid expenses and deposits and have been reclassified to conform with current period presentation.

Rubellite is exposed to market risk associated with its investment in marketable securities, primarily resulting from changes in the market price and liquidity of those securities. The market price of the 2.08 million Topaz shares may fluctuate and could be adversely affected by a variety of factors, including general market and economic conditions, the investee's operating and financial performance, public disclosures, commodity prices, interest and foreign exchange rates, geopolitical developments in the jurisdictions where the investee operates, and other factors beyond the Company's control.

## OFF BALANCE SHEET ARRANGEMENTS

Rubellite has no material off balance sheet arrangements.

## NON-GAAP AND OTHER FINANCIAL MEASURES

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

**Non-GAAP Financial Measures**

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

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

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| *($ thousands)* | **2026** | 2025 | **2026** | 2025 |
| Net cash flows used in investing activities | **(51,387)** | (19,291) | **(120,834)** | (82,304) |
| Payment for asset swap | **—** | — | **(800)** | **—** |
| Dispositions[2] | **—** | 5,500 | **—** | 5,500 |
| Change in non-cash working capital | **(8,011)** | 10,574 | **(111)** | 3,661 |
| Total capital expenditures | **(43,376)** | (35,365) | **(119,923)** | (91,465) |
| | | | | |
| Property, plant and equipment additions | **(40,961)** | (34,854) | **(110,315)** | (84,407) |
| Exploration and evaluation additions | **(2,296)** | (312) | **(9,203)** | (6,662) |
| Corporate expenditures | **(119)** | (199) | **(405)** | (396) |
| Total capital expenditures | **(43,376)** | (35,365) | **(119,923)** | (91,465) |
| Add back: | | | | |
| Corporate and other | **119** | 199 | **405** | 396 |
| Geological and geophysical | **385** | 231 | **1,279** | 1,178 |
| Land | **1,585** | 1,232 | **4,611** | 10,109 |
| Exploration and development spending[1] | **(41,287)** | (33,703) | **(113,628)** | (79,782) |

(1) Non-GAAP supplementary measure. See "Supplementary Measures".
(2) Dispositions includes cash consideration only.

**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 September 30, | | |
|---|---|---|---|---|
| *($ thousands, except per boe amounts*) | ***$/boe*** | **2026** | *$/boe* | 2025 |
| Net operating costs | **9.27** | **10,344** | 6.46 | 7,206 |
| Transportation | **5.88** | **6,562** | 4.66 | 5,201 |
| General and administrative | **2.39** | **2,672** | 3.24 | 3,615 |
| Cash finance expense | **2.43** | **2,709** | 2.30 | 2,568 |
| Cash costs | **19.97** | **22,287** | 16.66 | 18,590 |

| | | Nine months ended September 30, | | |
|---|---|---|---|---|
| *($ thousands, except per boe amounts*) | ***$/boe*** | **2026** | *$/boe* | 2025 |
| Net operating costs | **7.71** | **27,628** | 6.72 | 22,593 |
| Transportation | **5.30** | **18,994** | 5.40 | 18,139 |
| General and administrative | **3.06** | **10,953** | 3.58 | 12,044 |
| Cash finance expense | **2.13** | **7,621** | 2.19 | 7,366 |
| Cash costs | **18.20** | **65,196** | 17.89 | 60,142 |

**Operating netbacks and total operating netback, after risk management contracts:** Operating netback is calculated by deducting royalties, net operating costs, 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 netback, after risk management contracts, is presented after adjusting for realized gains or losses from risk management contracts. Rubellite considers operating netback and total operating netback, after risk management contracts to be key industry performance indicators that provide 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 total operating netback, after risk management contracts, are used to evaluate operational performance as they demonstrate profitability relative to realized and current commodity prices.

**Net operating costs:** Net operating costs equals operating expenses net of processing 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 September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| (*$ thousands, except per boe amounts*) | **2026** | 2025 | **2026** | 2025 |
| Other income | **821** | 75 | **1,148** | 580 |
| Less: Non-processing income | **(729)** | — | **(729)** | (343) |
| Processing income | **92** | 75 | **419** | 237 |
| | | | | |
| Production and operating | **10,436** | 7,281 | **28,047** | 22,830 |
| Less: processing income | **(92)** | (75) | **(419)** | (237) |
| Net operating costs | **10,344** | 7,206 | **27,628** | 22,593 |
| *$/boe* | **9.27** | 6.46 | **7.71** | 6.72 |

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

**Net Debt and Adjusted Working Capital:** Rubellite uses net debt as an alternative measure of outstanding debt and is calculated by adding borrowings under the credit facility plus the principal amount of term loan debt, less marketable securities and 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 September 30, 2026** | As of December 31, 2025 |
|---|---|---|
| Current assets[(1)] | **97,581** | 35,181 |
| Current liabilities | **(111,155)** | (70,413) |
| Working capital deficit | **(13,574)** | (35,232) |
| Risk management contracts – current asset | **(311)** | (5,828) |
| Marketable securities - current asset | **(59,731)** | (438) |
| Risk management contracts – current liability | **28,029** | 327 |
| Lease liability - current liability | **410** | 389 |
| Share based compensation liability - current liability | **9,399** | 4,694 |
| Decommissioning obligations – current liability | **1,340** | 1,340 |
| Other provision - current liability | **3,750** | 3,750 |
| Adjusted working capital deficit[(1)] | **(30,688)** | (30,998) |
| Marketable securities | **59,731** | 438 |
| Bank indebtedness | **(118,034)** | (92,583) |
| Term loan (principal) | **(20,000)** | (20,000) |
| Net debt[(2)] | **(108,991)** | (143,143) |

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

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

**Adjusted funds flow before transaction costs:** Adjusted funds flow before transaction costs is calculated as adjusted funds flow plus transaction costs incurred in connection with acquisitions, dispositions and other corporate transactions. Management believes that excluding transaction costs, which relate to specific corporate transactions and are not indicative of the Company's ongoing operations, provides a more comparable measure of the funds generated by the Company's ongoing operations between periods. The most directly comparable IFRS measure is net cash flows from operating activities. Adjusted funds flow before transaction costs is not a standardized measure and may not be comparable to similar measures presented by other entities.

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 September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| (*$ thousands, except as noted*) | **2026** | 2025 | **2026** | 2025 |
| Net cash flows from operating activities | **30,714** | 34,953 | **98,063** | 97,896 |
| Change in non-cash working capital | **4,173** | (1,223) | **482** | 3,352 |
| Cash-settled share based compensation | **498** | 1,539 | **1,298** | 2,624 |
| Other provision settled | **—** | — | **3,750** | 3,750 |
| Accrued interest on other provision | **(140)** | — | **(284)** | — |
| Decommissioning obligations settled | **200** | 394 | **748** | 1,286 |
| Adjusted funds flow | **35,445** | 35,663 | **104,057** | 108,908 |
| Transaction costs | **398** | — | **398** | — |
| Adjusted funds flow, before transaction costs | **35,843** | 35,663 | **104,455** | 108,908 |
| | | | | |
| Adjusted funds flow per share - basic | **0.38** | 0.38 | **1.11** | 1.17 |
| Adjusted funds flow per share - diluted | **0.38** | 0.37 | **1.11** | 1.14 |
| Adjusted funds flow per boe | **31.77** | 31.99 | **29.05** | 32.41 |
| | | | | |
| Adjusted funds flow per share - before transaction costs - basic | **0.38** | 0.38 | **1.11** | 1.17 |
| Adjusted funds flow per share - before transaction costs - diluted | **0.38** | 0.37 | **1.11** | 1.14 |
| Adjusted funds flow per boe - before transaction costs | **32.13** | 31.99 | **29.16** | 32.41 |

**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 their most directly comparable GAAP measures 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 September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| (*$ thousands*) | **2026** | 2025 | **2026** | 2025 |
| Adjusted funds flow | **35,445** | 35,663 | **104,057** | 108,908 |
| Total capital expenditures | **(43,376)** | (35,365) | **(119,923)** | (91,465) |
| Free funds flow | **(7,931)** | 298 | **(15,866)** | 17,443 |

**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 oil and natural gas producers. Rubellite also calculates certain non-GAAP measures per share as the measure divided by outstanding common shares, weighted average common shares or diluted weighted average common shares.

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

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

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

**Net debt as a percentage of enterprise value:** calculated by dividing net debt by enterprise value at the end of the period.

**Adjusted funds flow per share:** calculated as adjusted funds flow divided by the basic or diluted weighted average number of common shares outstanding for the period, consistent with the share amounts used to calculate net income (loss) per share in the Company's interim consolidated financial statements. In periods of net loss, diluted weighted average shares equal basic weighted average shares, as potentially dilutive instruments are anti-dilutive. Adjusted funds flow per share before transaction costs is calculated on the same basis.

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

**Supplementary Financial Measures**

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

"Average realized price" is comprised of total oil and natural gas revenue, as determined in accordance with IFRS, divided by the Company's total sales production on a per boe 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 bbl" 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 total oil and natural gas revenue, 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 cost per boe" is comprised of net operating cost (as calculated above), divided by the Company's total sales production.

"Transportation cost ($/boe)" is comprised of transportation, 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 and depreciation 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 at period end.

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

## FUTURE ACCOUNTING PRONOUNCEMENTS

**Future Accounting Pronouncements**

IFRS 18 *Presentation and Disclosure in Financial Statements*

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

IFRS 18 does not alter the recognition or measurement of items included in the statement of income and comprehensive income; it changes how those items are presented. Impacts of IFRS 18 on the Company are expected to include:

- the statement of income (loss) and comprehensive income (loss) will present income and expenses within defined categories, including operating, investing and financing. Finance expense will be presented within the financing category, and dividend income and changes in the fair value of marketable securities, will be presented within the investing category;
- increased disclosure in the financial statements in respect of management defined performance measures, such as operating netback and total operating netback, after risk management contracts; and
- consequential amendments to the statement of cash flows, whereby the starting point for cash flows from operating activities will be a new subtotal referred to as operating profit (loss), and the policy option in respect of reporting interest paid within operating activities has been removed, with interest paid required to be reported within financing activities and dividends received, currently reported within operating activities, required to be reported within investing activities.

Certain of the non-GAAP financial measures presented in this MD&A are expected to be presented in the Company's financial statements upon adoption of IFRS 18. The Company is completing its evaluation of the impact of adopting IFRS 18 on its consolidated financial statements.

## 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 July 1, 2026 and ending September 30, 2026 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, and the benefits to be derived from such drilling including drilling techniques, pilot projects and production growth including the timing for and benefits of EOR initiatives; the plan to advance strategic initiatives including multiple enhanced oil recovery pilots, exploration activities, new land capture, capital spending activities, anticipated average heavy oil sales volumes and total production sales volumes in 2026; operating and transportation cost forecasts for 2026; planned ARO spending; Rubellite's business plan; and including the forward-looking information contained under the headings "Operations Update" 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, 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, 2025 and in other reports on file with Canadian securities regulatory authorities which may be accessed through the SEDAR+ website www.sedarplus.ca and at Rubellite's website www.rubelliteenergy.com. Readers are cautioned that the foregoing list of risk factors is not exhaustive. Forward-looking information is based on the estimates and opinions of Rubellite's management at the time the information is released, and Rubellite disclaims any intent or obligation to update publicly any such forward-looking information, whether as a result of new information, future events or otherwise, other than as expressly required by applicable securities law.

## ABBREVIATIONS AND CONVENTIONS

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

**Measurement:**

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

**Industry Metrics:**

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

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

**Volume Conversions:**

Barrel of oil equivalent ("boe") may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), a conversion ratio for conventional natural gas of 6 Mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indicator of value as the value ratio between conventional natural gas and heavy crude oil, based on the current prices of natural gas and crude oil, differs significantly from the energy equivalency of 6 Mcf:1 bbl. A conversion ratio of 1 bbl of heavy crude oil to 1 bbl of NGL has also been used throughout this MD&A.

**Initial Production Rates:**

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

**Financial and Business Environment:**

| | |
|---|---|
| AECO | Alberta Energy Company |
| E&E | Exploration and evaluation |
| EOR | Enhanced oil recovery |
| 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 |
| OBM | Oil based mud |
| PP&E | Property, plant and equipment |
| WTI | West Texas Intermediate |
| WCS | Western Canadian Select |

## SUMMARY OF QUARTERLY RESULTS

| *($ thousands, except as noted)* | Q3 2026 | Q2 2026 | Q1 2026 | Q4 2025 |
|---|---|---|---|---|
| **Financial** | | | | |
| Oil and natural gas revenue | **81,683** | 86,063 | 66,243 | 56,261 |
| Net income (loss) and comprehensive income (loss) | **(27,133)** | 34,119 | (23,071) | 9,700 |
| Per share – basic[2] | **(0.29)** | 0.36 | (0.25) | 0.10 |
| Per share – diluted[2] | **(0.29)** | 0.35 | (0.25) | 0.10 |
| Total assets | **630,095** | 615,606 | 597,152 | 578,509 |
| Cash flow from operating activities | **30,714** | 42,770 | 24,579 | 30,900 |
| Adjusted funds flow, before transaction costs[1] | **35,843** | 35,245 | 33,367 | 33,165 |
| Per share – basic[1][2] | **0.38** | 0.38 | 0.36 | 0.35 |
| Per share – diluted[1][2] | **0.38** | 0.36 | 0.36 | 0.34 |
| Adjusted funds flow, after transaction costs[1][5] | **35,445** | 35,245 | 33,367 | 33,165 |
| Per share – basic[1][2] | **0.38** | 0.38 | 0.36 | 0.35 |
| Per share – diluted[1][2] | **0.38** | 0.36 | 0.36 | 0.34 |
| Total capital expenditures[1][3][4] | **43,376** | 43,883 | 32,664 | 39,037 |
| **Common shares** (thousands) | | | | |
| Weighted average – basic | **94,005** | 93,859 | 93,590 | 94,488 |
| Weighted average – diluted | **94,005** | 98,313 | 93,590 | 97,478 |
| **Sales Production** | | | | |
| Heavy oil (bbl/d) | **8,542** | 8,534 | 8,641 | 8,295 |
| Natural gas (Mcf/d) | **19,641** | 26,576 | 28,532 | 25,884 |
| NGL (bbl/d) | **312** | 443 | 447 | 433 |
| Daily average sales production (boe/d) | **12,128** | 13,406 | 13,843 | 13,042 |
| **Rubellite average realized price[1]** | | | | |
| Oil ($/bbl) | **97.62** | 101.17 | 74.42 | 63.32 |
| Natural gas ($/Mcf) | **1.64** | 1.73 | 2.27 | 2.47 |
| NGL ($/bbl) | **69.83** | 81.97 | 63.10 | 51.93 |
| Total average realized price ($/boe) | **73.21** | 70.54 | 53.17 | 46.89 |
| Average realized price, after risk management contracts[1] ($/boe) | **63.64** | 58.70 | 49.37 | 49.20 |
| **Operating netback ($/boe)** | | | | |
| Revenue[1] | **73.21** | 70.54 | 53.17 | 46.89 |
| Royalties[1] | **(12.19)** | (10.53) | (7.02) | (6.14) |
| Net operating costs[1] | **(9.27)** | (8.16) | (5.89) | (5.80) |
| Transportation costs[1] | **(5.88)** | (5.58) | (4.52) | (4.57) |
| Operating netback[1] | **45.87** | 46.27 | 35.74 | 30.38 |
| Realized gain (loss) on risk management contracts[1] | **(9.57)** | (11.84) | (3.80) | 2.31 |
| Total operating netback, after risk management contracts[1] | **36.30** | 34.43 | 31.94 | 32.69 |
| G&A Costs[1] | **(2.39)** | (3.24) | (3.48) | (3.19) |
| Cash interest costs[1] | **(2.43)** | (2.31) | (1.68) | (1.85) |
| Other Income[1][6] | **0.65** | — | — | — |
| Adjusted funds flow, before transaction costs[1] | **32.13** | 28.88 | 26.78 | 27.65 |

(1) Non-GAAP measure, ratio or supplementary measure. See "Non-GAAP and Other Financial Measures".
(2) Per share amounts are calculated using the weighted average number of basic or diluted common shares.
(3) Includes cash and non-cash consideration.
(4) In Q4 2025, the Company disposed of non-producing acreage for cash consideration of $2.3 million, with a net book value of nil, resulting in a corresponding gain on disposition of assets.
(5) Q3 2026 includes $0.4 million of transaction costs related to the East Edson Disposition.
(6) Q3 2026 other income includes $0.7 million of dividends received on the Topaz shares received as consideration for the East Edson Disposition.

| *($ thousands, except as noted)* | Q3 2025 | Q2 2025 | Q1 2025 | Q4 2024 |
|---|---|---|---|---|
| **Financial** | | | | |
| Oil and natural gas revenue | 58,290 | 60,542 | 66,607 | 59,081 |
| Net income and comprehensive income | 5,646 | 16,051 | 1,160 | 26,747 |
| Per share – basic[2] | 0.06 | 0.17 | 0.01 | 0.31 |
| Per share – diluted[2] | 0.06 | 0.17 | 0.01 | 0.30 |
| Total assets | 558,709 | 561,545 | 551,889 | 562,612 |
| Cash flow from operating activities | 34,953 | 35,808 | 27,135 | 39,402 |
| Adjusted funds flow, before transaction costs[1] | 35,663 | 37,311 | 35,934 | 35,855 |
| Per share – basic[1][2] | 0.38 | 0.40 | 0.39 | 0.41 |
| Per share – diluted[1][2] | 0.37 | 0.39 | 0.38 | 0.40 |
| Adjusted funds flow, after transaction costs[1][4] | 35,663 | 37,311 | 35,934 | 31,632 |
| Per share – basic[1][2] | 0.38 | 0.40 | 0.39 | 0.36 |
| Per share – diluted[1][2] | 0.37 | 0.39 | 0.38 | 0.36 |
| Total capital expenditures[1][5] | 35,365 | 31,168 | 24,932 | 35,537 |
| Acquisitions[3] | — | — | — | 68,467 |
| **Common shares** (thousands) | | | | |
| Weighted average – basic | 93,700 | 93,279 | 92,930 | 87,655 |
| Weighted average – diluted | 96,311 | 95,074 | 95,068 | 88,546 |
| **Sales Production** | | | | |
| Heavy oil (bbl/d) | 8,338 | 8,637 | 8,339 | 7,754 |
| Natural gas (Mcf/d) | 20,975 | 20,522 | 22,038 | 14,140 |
| NGL (bbl/d) | 288 | 368 | 371 | 275 |
| Daily average sales production (boe/d) | 12,122 | 12,425 | 12,383 | 10,386 |
| **Rubellite average realized price[1]** | | | | |
| Oil ($/bbl) | 72.40 | 69.98 | 80.03 | 76.97 |
| Natural gas ($/Mcf) | 0.66 | 1.93 | 2.16 | 2.01 |
| NGL ($/bbl) | 56.12 | 57.92 | 67.54 | 61.32 |
| Total average realized price ($/boe) | 52.27 | 53.54 | 59.77 | 61.83 |
| Average realized price, after risk management contracts[1] ($/boe) | 55.83 | 57.81 | 59.60 | 65.14 |
| **Operating netback ($/boe)** | | | | |
| Revenue[1] | 52.27 | 53.54 | 59.77 | 61.83 |
| Royalties[1] | (7.18) | (6.75) | (8.48) | (8.10) |
| Net operating costs[1] | (6.46) | (6.71) | (7.00) | (6.84) |
| Transportation costs[1] | (4.66) | (5.93) | (5.59) | (6.01) |
| Operating netback[1] | 33.97 | 34.15 | 38.70 | 40.88 |
| Realized gain (loss) on risk management contracts[1] | 3.56 | 4.27 | (0.17) | 3.31 |
| Total operating netback, after risk management contracts[1] | 37.53 | 38.42 | 38.53 | 44.19 |
| G&A Costs[1] | (3.24) | (3.55) | (3.96) | (3.69) |
| Cash interest costs[1] | (2.30) | (2.07) | (2.21) | (2.98) |
| Adjusted funds flow, before transaction costs[1] | 31.99 | 32.80 | 32.36 | 37.52 |

(1) Non-GAAP measure, ratio or supplementary measure. See "Non-GAAP and Other Financial Measures".
(2) Per share amounts are calculated using the weighted average number of basic or diluted common shares.
(3) Includes cash and non-cash consideration.
(4) Q4 2024 includes $4.2 million of transaction costs related to prior period transactions.
(5) In Q3 2025, the Company disposed of non-producing acreage for cash consideration of $5.5 million, with a net book value of nil, resulting in a corresponding gain on disposition of assets.

Oil and natural gas revenue has ranged between $56.3 million and $86.1 million over the prior eight quarters, reflecting changes in sales production, which ranged from 10,386 boe/d to 13,843 boe/d and volatility in commodity prices. Net income (loss) has ranged from a loss of $27.1 million to income of $34.1 million primarily due to increased production, corporate acquisitions and dispositions, volatility of commodity prices and its impact on revenue, royalties, realized and unrealized risk management contract gains and losses and deferred income taxes.