Rubellite Energy Inc.

Corporate Overview

August 10, 2023

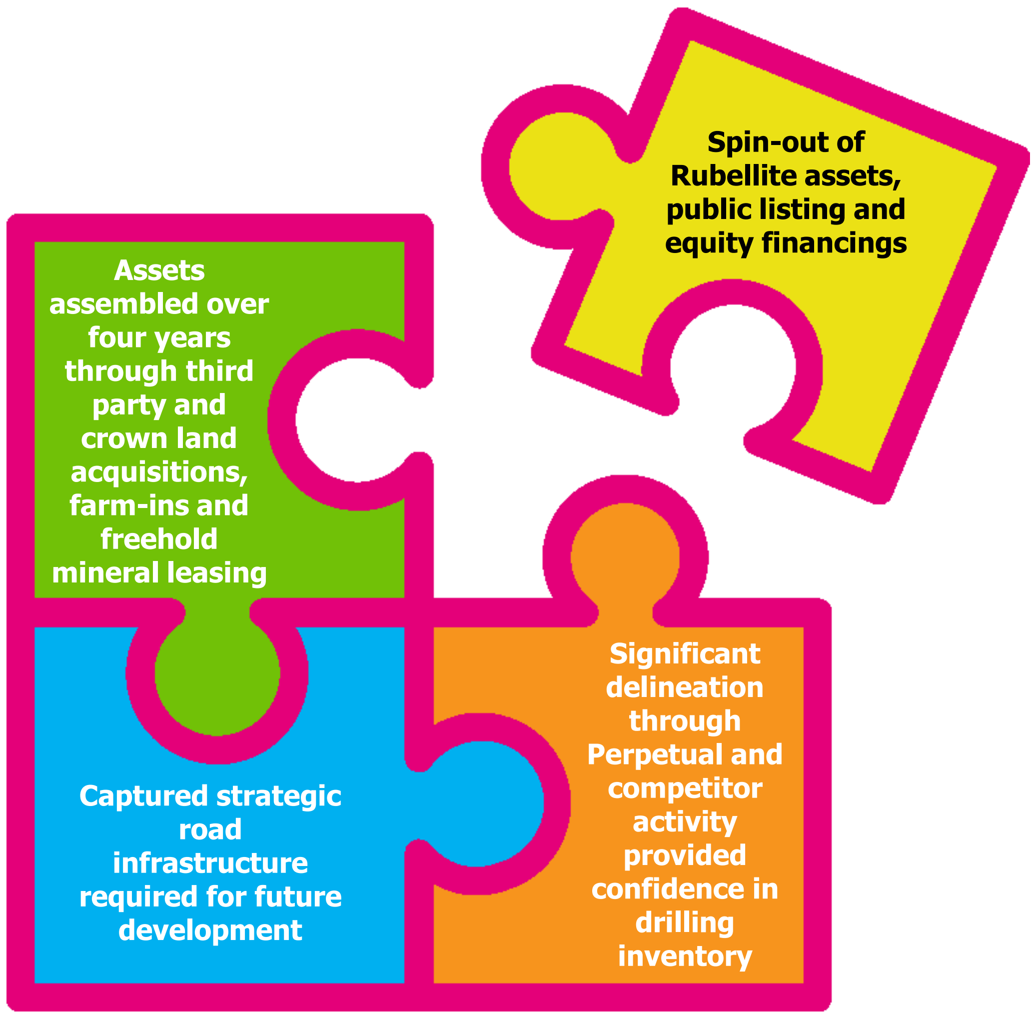
Corporate Profile

High growth-focused, pure play Clearwater E&P company (TSX:RBY)

Since 2018, Perpetual / Rubellite has executed 50+ separate transactions to assemble access to 315 net sections across the Clearwater fairway

- Rubellite acquired all of Perpetual's Clearwater Assets for total consideration of $65.5 MM (including $59.2 MM in cash)
  - Incorporated on July 12, 2021; Clearwater Assets conveyed on July 15th
  - Plan of Arrangement closed on September 3rd
  - Equity Financings closed / released from Escrow on Oct 5, 2021
- $83.5 MM in Equity Financings (October 5, 2021):
  - $30.0 MM Brokered Sub-Receipts Financing (closed into escrow July 13th)
  - $20.0 MM Non-Brokered Private Placement
  - $33.5 MM Arrangement Warrant ("rights offering") Financing for Perpetual shareholders fully backstopped by Sue Riddell Rose, President & CEO
  - All components of the financings priced at $2.00/share
- $38.7 MM in Equity Financings (March 30, 2022):
  - $25.3 MM Brokered Financing; $13.4 MM Non-Brokered Private Placement
  - Both financings priced at $3.55/share
- $20.0 MM Flow-Through Equity Financing (March 28, 2023):
  - Non-Brokered Private Placement priced at $2.85/share

TSX	RBY
Shares Outstanding[1]	61.8 MM
Market Capitalization[2]	$126.8 MM
Net Debt (June 30, 2023)	$20.7 MM
Enterprise Value	$147.4 MM
Insider Ownership	~37.8%



1. *68.5 MM fully diluted including 4.0 MM Share Purchase Warrants (owned by Perpetual)*
2. *TSX:RBY August 9, 2023 closing price of $2.05/share*

Investment Highlights

Robust growth opportunity in the prolific Clearwater play

Expanding Pure Play Clearwater Asset Base

- High growth-focused, pure play Clearwater E&P company
- ~315 net sections of prospective Clearwater lands and ~200 Development / Step-out drilling locations
- Multiple exploration prospects captured with material location inventory potential if successful
- Line of sight to additional exploratory land capture and M&A opportunities
- Rubellite controls and operates 100% of its Clearwater asset base

Robust Organic Production Growth Profile

- Organic production growth from initial 350 bbl/d in September 2021 to ~2,844 bbl/d average Q2 2023
- Highly profitable, full cycle IRRs with attractive payout periods at current strip prices
- Development / Step-out drilling ongoing to validate and refine type curves
- Evaluation of exploration prospect inventory to inform sustainable target production level

Fully Funded Development Unlocking Free Funds Flow

- Rapid, organic growth plan financed through equity, adjusted funds flow and available credit facilities
- Total cash costs of ~$19.50 to $21.00/bbl drives attractive netbacks at strip pricing
- Extensive infrastructure in core operating areas drives attractive capital efficiencies
- Future waterflood and EOR potential to mitigate production declines and increase recovery

Conservative Capitalization and Risk Mitigation

- $40 MM bank credit facility
- Risk management with hedging to protect capital investment plans and returns during growth ramp
- Line of sight to sustainable free funds flow; timing dependent on commodity prices, delineation results, exploration success and chosen pace of growth
- Free funds flow could be directed to accelerated organic growth, additional exploration activities, acquisitions and returns to shareholders

Management Alignment and ESG Excellence

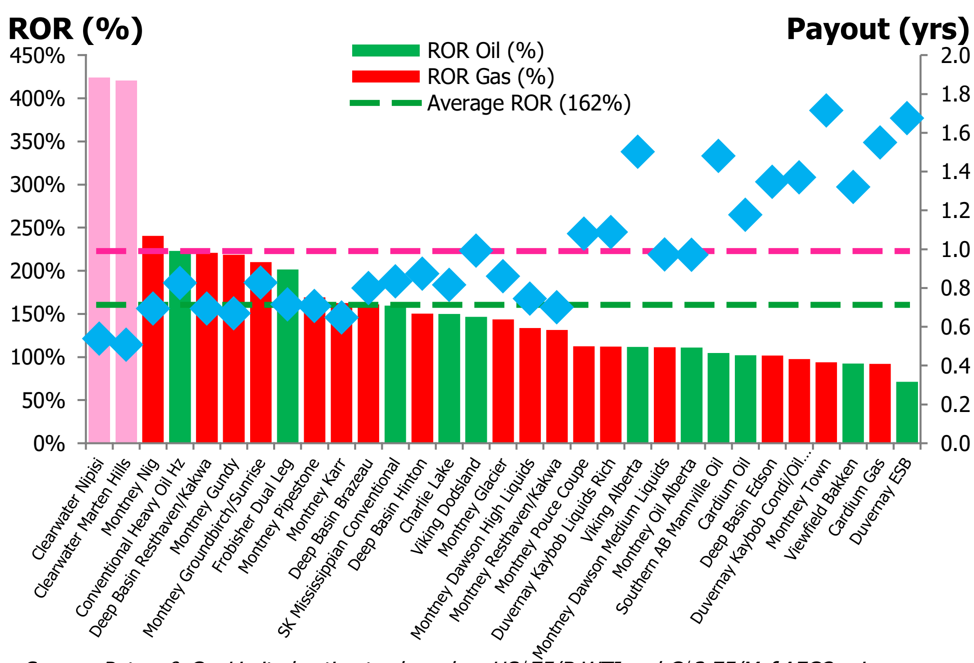
- Strong management alignment with insider ownership of ~37.8%
- Majority independent board members ensures solid governance
- Unstimulated, multi-lateral drilling technology from multi-well pads supports environmentally responsible development with limited surface footprint and negligible use of freshwater

Clearwater Play Landscape

Amongst the best single well economics of any play in North America

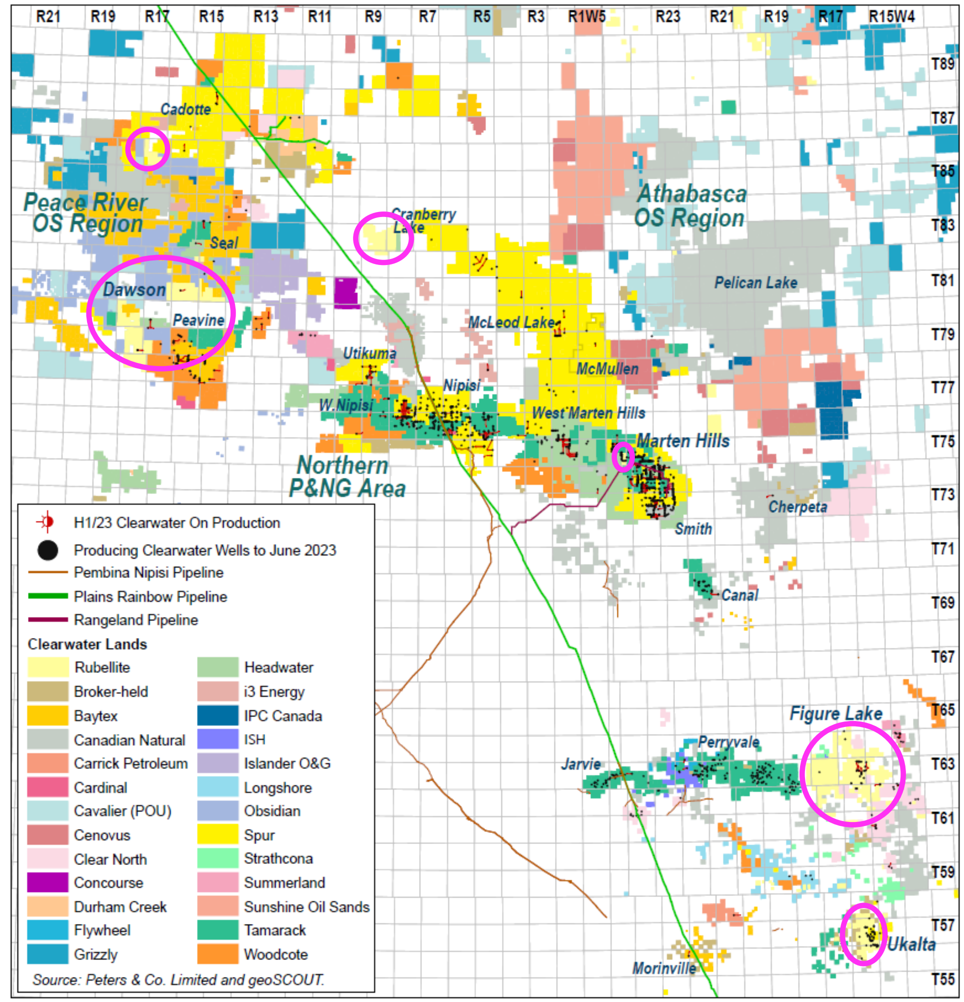
Clearwater Play Evolution

- Since 2017, > 1,250 wells have been drilled, growing play production from nil to ~121,000 bbl/d by Q2 2023
  - ~75% of production at Marten Hills and Nipisi
  - Additional pools proven to the north at Peavine, Seal, Utikuma & Golden; and to the south at Jarvie, Newbrook, Ukalta & Figure Lake
- Primary recovery heavy oil utilizing horizontal multi-lateral drilling
- Secondary recovery waterfloods initiated in multiple areas



Source: Peters & Co. Limited estimates based on US$75/B WTI and C$3.75/Mcf AECO prices
Rate of Return (ROR) calculated as NPV10 / Initial Capital Spend

Clearwater Play

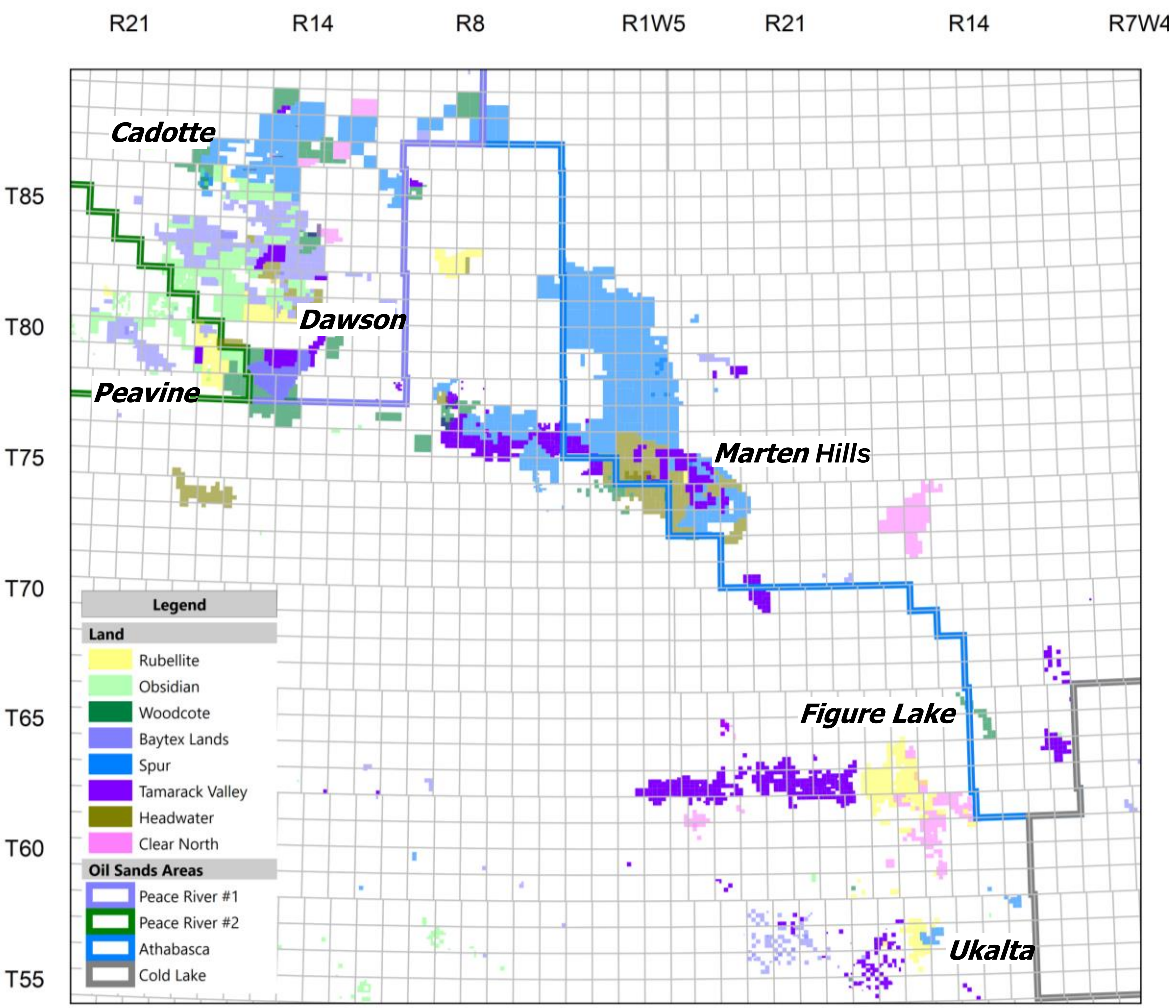


Early development of Clearwater Play focused on Marten Hills and Nipisi
Numerous new areas within the Clearwater fairway proving to be highly economic

Rubellite Asset Profile

315 net sections of prospective land; ~200 development / step-out Clearwater locations

Asset Map



Source: geoScout and competitor disclosures

Asset Summary:

Area	Land Net (sections)[1]	Well Count Net (producing)[3]	Production Q2 2023 (bbl/d)[4]
Figure Lake	122	29.0	1,798
Ukalta	34.5	26.0	677
Marten Hills[3][5]	0.9	3.3	368
Northern Exploration[2][3]	70	0.0	0
Other Exploration	88	3.0	0
TOTAL	**315.4[2][5]**	**61.3[3][5]**	**2,844**

1. *318.4 net sections at Before Payout Working Interest (315.4 net sections After Payout).*
2. *Includes Peavine, Dawson and Cadotte exploratory lands at after payout working interest where drilling/work commitments are required for earning.*
3. *Well count contributing to production during Q2 2023 was 69 gross (61.3 net APO). Producing well counts at Aug 10, 2023 is 72 gross (64.3 net APO), including 3 additional wells at Figure Lake, and continued shut in of 3 gross (1.55 net APO) Northern Exploration wells due to winter only access.*
4. *100% conventional heavy crude.*
5. *Production at Marten Hills is reported at the After Payout Working Interest for the first 6 Test Wells. Project Payout occurred in January 2023 and the Farmor election to convert to a Working Interest was received effective May 1, 2023.*
6. *Total Proved Plus Probable (P+PUD) reserves as per Year End 2022 McDaniel Reserve Report.*

Q2 2023 production: 2,844 bbl/d

- Decrease from Q1 2023 production of 2,990 bbl/d due Working Interest payout conversion at Marten Hills to 30%

Reserves[6]: Total proved plus probable of 10.2 MMbbl

Property Status:

Marten Hills - Developed on primary; Secondary recovery potential

Ukalta - Development ongoing

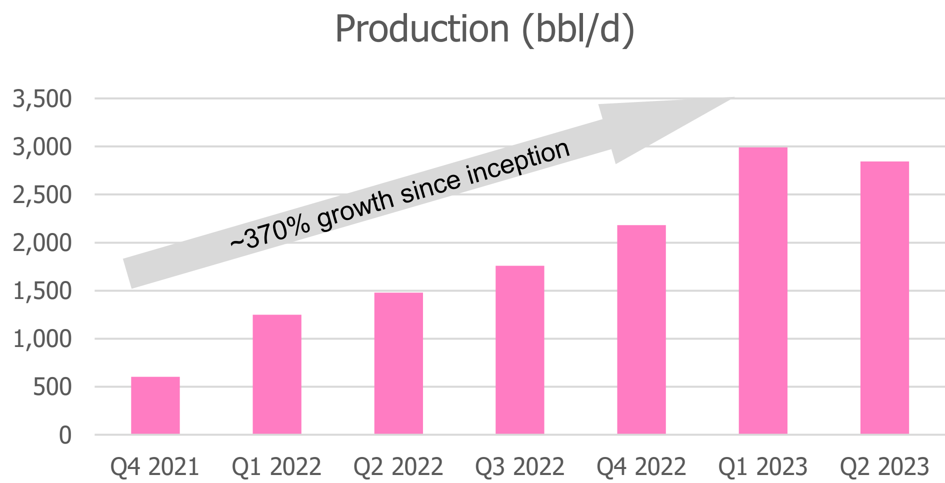
Figure Lake - Development and Step-out/extension ongoing

Northern Exploration - De-risking prospects at Dawson

Other Exploration - Various stages of land capture & assessment

Corporate Performance

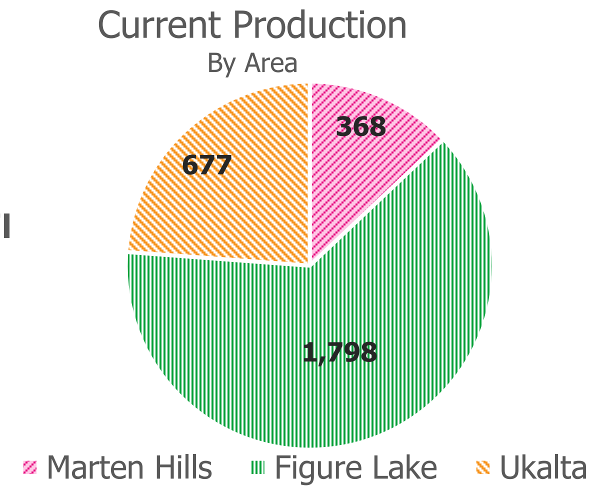
Operational Momentum and Focus

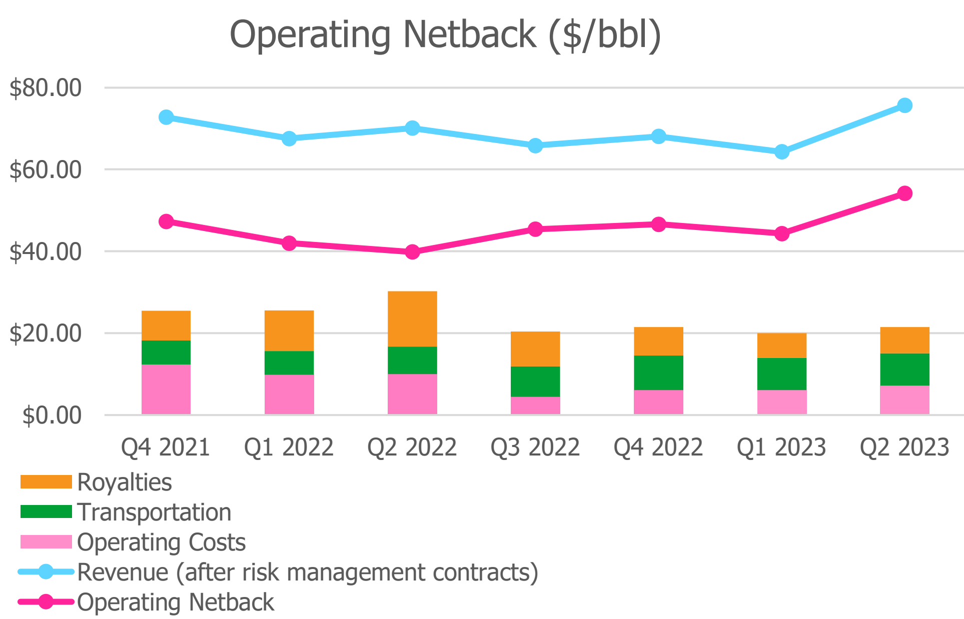


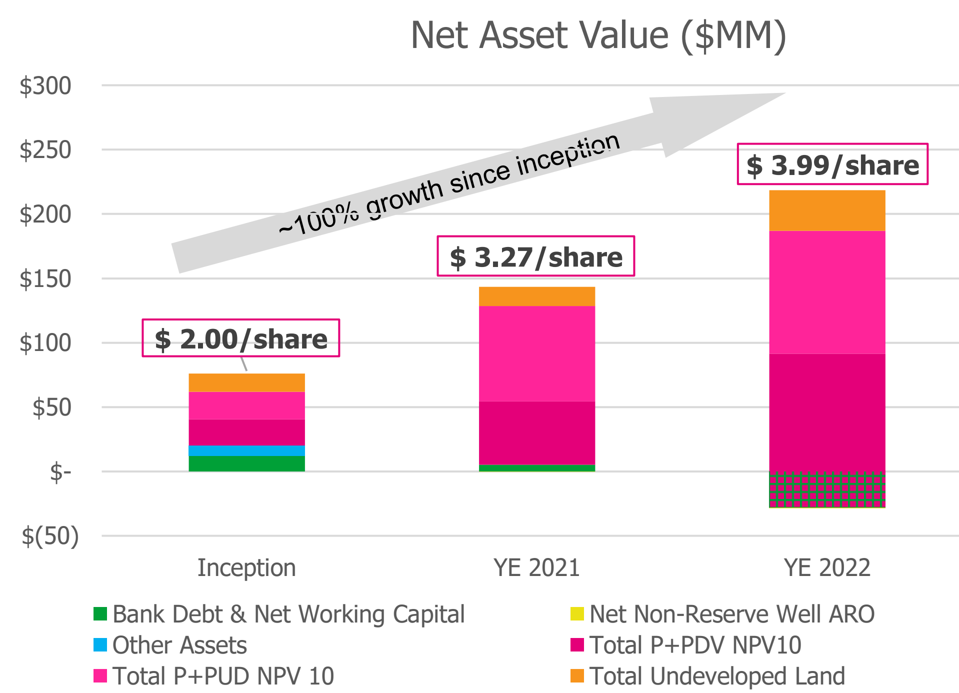
Q2 2023[1]

2,844 bbl/d

100% Heavy Oil





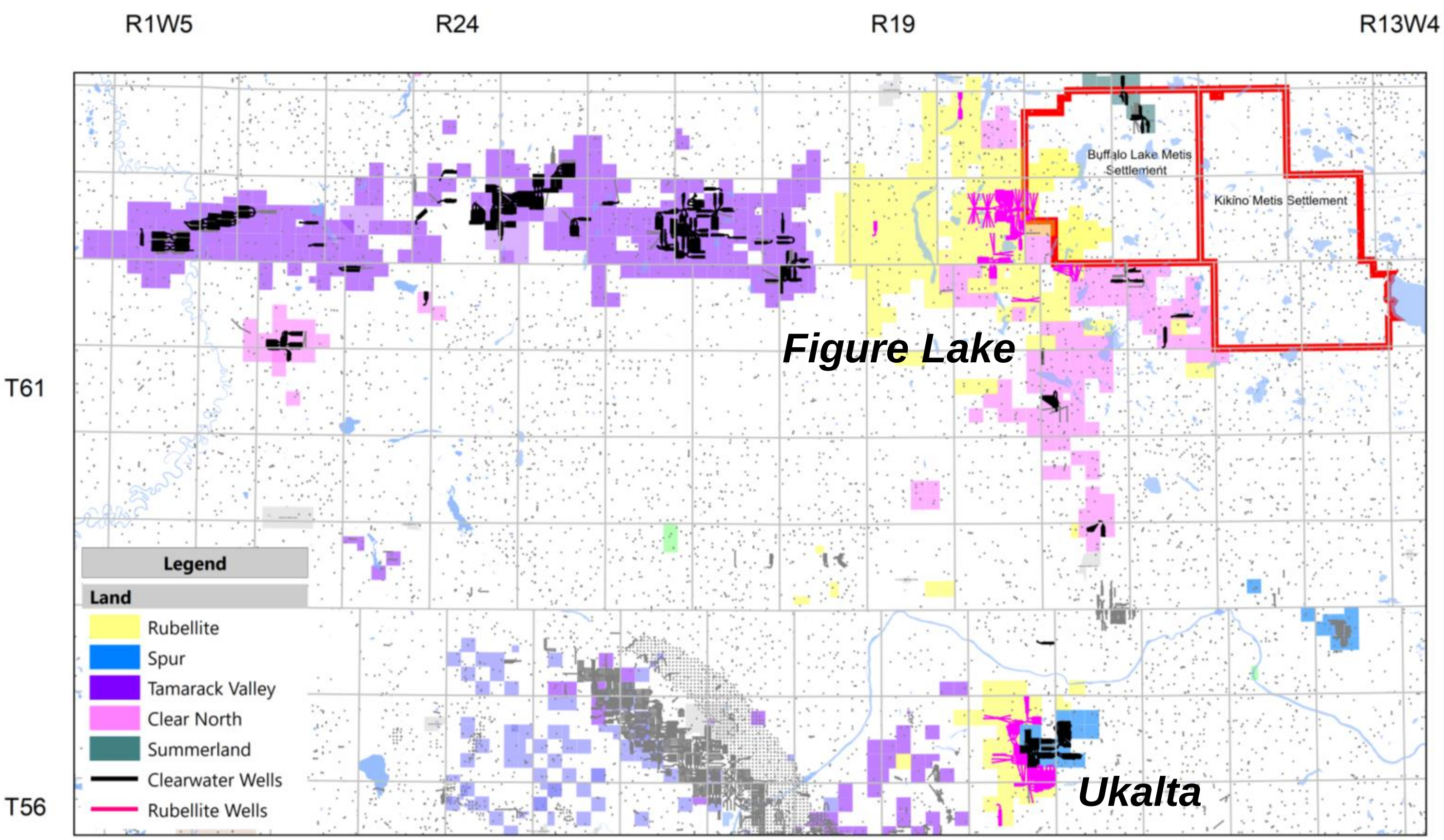


1. *Reflects production reduction due to Working Interest conversion at payout at Marten Hills*
2. *Q2 2023 operating costs reflect carbon taxes for 2023 YTD ($0.32/boe)*

Southern Clearwater

Active Development and Extension Activity Ongoing

Southern Clearwater Play Fairway



Source: geoScout and competitor disclosures

RBY Play History

***Figure Lake* – Development & Step-out Delineation - Poised for Growth**

- 1,798 bbl/d Q2 2023 sales
- One 2.5-leg producing well drilled in early stage of play by a predecessor operator to set up exploration concept
- Sold top-up royalty to fund initial four well exploration program (South Pad & North Pad)
- South pad success activated 2022 development & step-out activity
- 29 (29.0 net) multi-lat wells onstream at the end of Q2 2023
- Development sweet spot identified to focus production growth

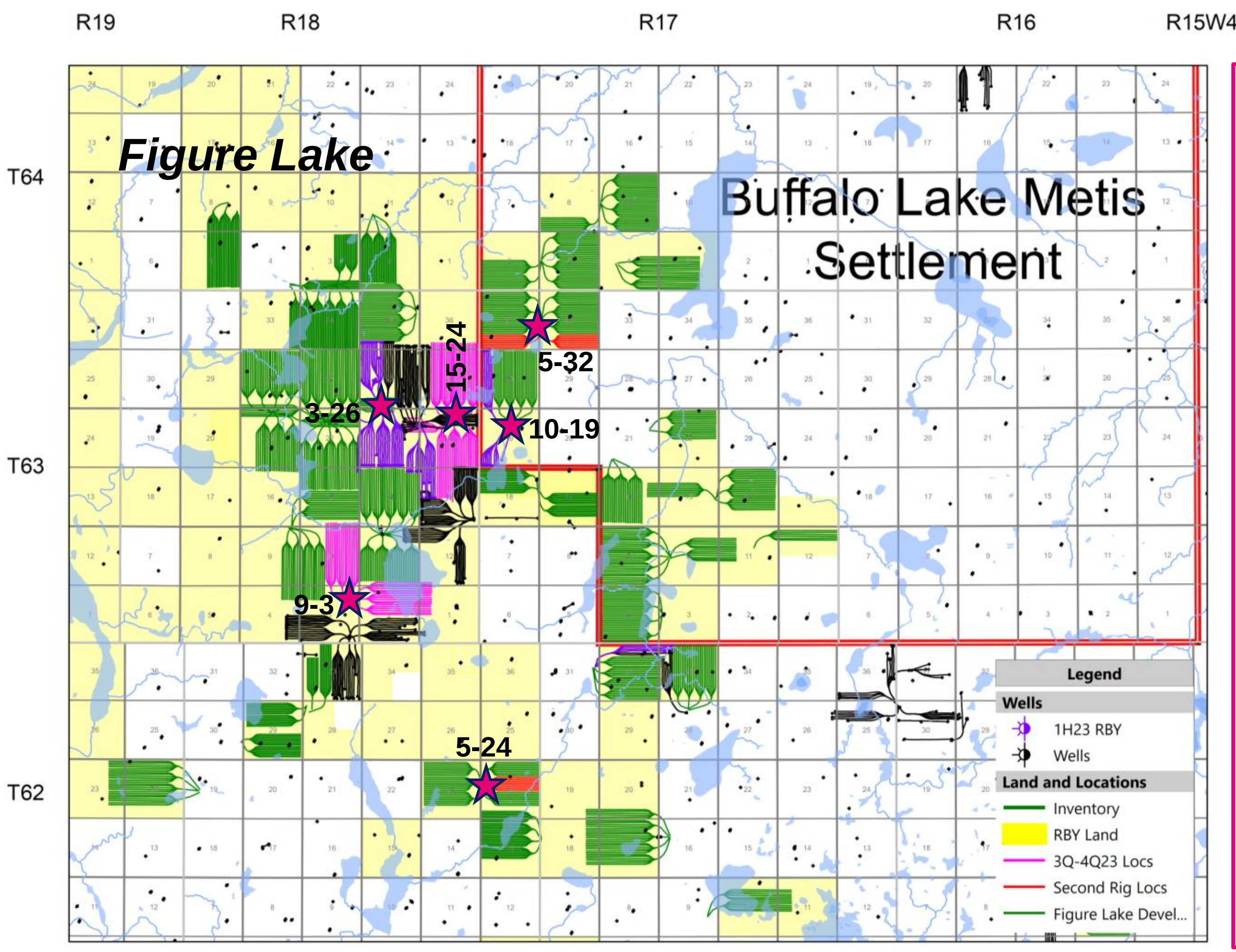
***Ukalta* – Development with Secondary Zone Exploration**

- 677 bbl/d Q2 2023 sales
- Six 6-leg wells on production at RBY inception
- 26 (26.0 net) wells onstream Q2 2023
- Active industry competitors include Spur and Tamarack Valley

Rubellite Asset Profile | *Figure Lake*

Pool Development and Extension

Asset Map



Source: GeoScout and competitor disclosures

Asset Summary

Working Interest: 100%

Q2 2023 Production: 1,798 bbl/d heavy oil

- 29 multi-laterals on sales production (including 3 exploratory wells at Skeleton and Alpen)

2023 Strategy

- Grow production with sweet-spot focused drilling program
- Manage land continuations & surface access restrictions
- Drill and evaluate southern area pool extension wells and BLMS lands to de-risk future development
- Refine optimal well design and type curves
- Execute 8 – 12 well "Mega-Pad" program to reduce development infill drilling costs by a targeted 15%
- Evaluate and advance enhanced recovery pilots
- Pursue gas conservation/monetization
- Expand land capture

1H 2023 Activity

- 10.0 net wells rig released (purple)

2H 2023 Activity

- 13.0 net infill at 15-24 and 9-3 Pads (pink)
- 2.0 - 3.0 net step out wells (red)

Prospect Inventory

- 45 booked[1] Primary Zone HZ Development locations
- 130 Additional identified locations

1. *Total Proved Plus Probable (P+PUD) reserve parameters as per Year End 2022 McDaniel Reserve Report*

Rubellite Asset Profile | *Figure Lake*

Ongoing drilling results refining Figure Lake type curve

Type Curve and Production Results

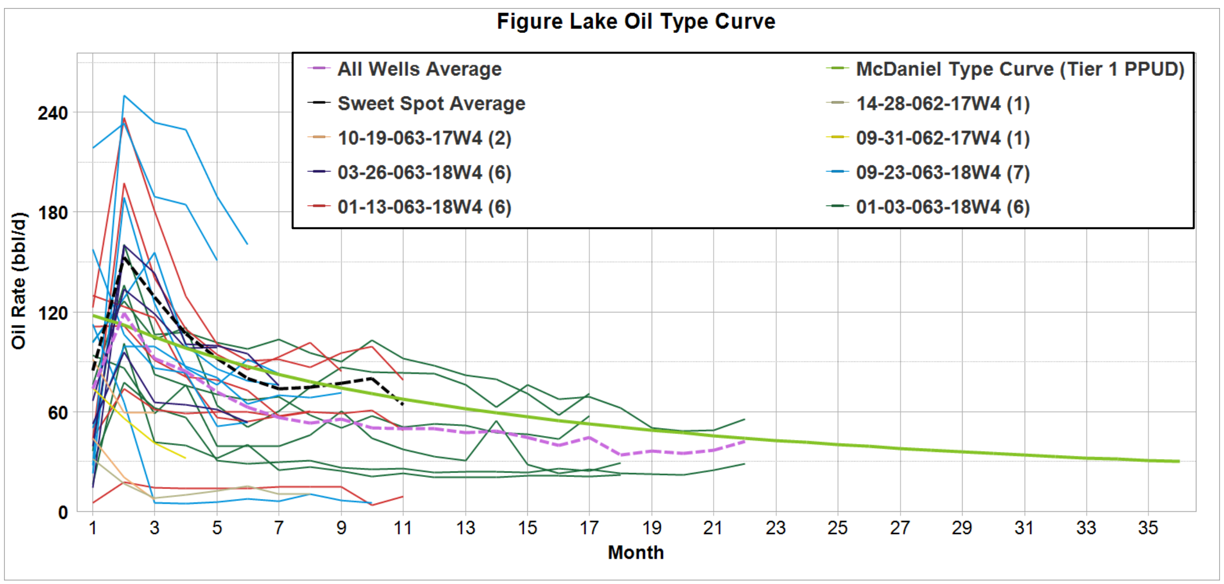
Figure Lake Development / Stepout wells
- 9 wells on production for 30+ day in 2023
  - Average IP30: 154 bbl/d
  - Average IP60: 127 bbl/d (8 wells)

Q1 2023 Drilling – Initial Production Results
- 9-23 Pad
  - 02/12-13-063-18W4: IP30 231 bbl/d; IP60 234 bbl/d
  - 03/05-13-063-18W4: IP30 259 bbl/d; IP60 233 bbl/d
- 3-26 Pad
  - 00/03-35-063-18W4: IP30 117 bbl/d (shorter well) IP60 91 bbl/d
  - 00/04-35-063-18W4: IP30 147 bbl/d; IP60 134 bbl/d
- 9-31 Pad
  - IP30 101 bbl/d; IP60 75 bbl/d
- 10-19 Pad
  - 00/13-30-063-17W4: IP30 111 bbl/d; IP60 87 bbl/d

Q2 2023 Drilling – Initial Production Results
- 10-19 Pad
  - 00/04-19-063-17W4: IP30 47 bbl/d; IP60 30 bbl/d
- 3-26 Pad
  - 02/03-23-063-18W4: IP30 164 bbl/d; IP60 139 bbl/d
  - 02/02-23-063-18W4: IP30 208 bbl/d
  - 00/04-23-063-18W4: IP30 173 bbl/d
- 15-24 Pad
  - 00/09-23-063-18W4: IP19 203 bbl/d

Type Curve Assumptions

Assumptions (8-leg multi-lateral ~9,000m)	Tier 1		Tier 2
	McDaniel PUD YE 2022 [1]	McDaniel PPUD YE 2022 [1]	McDaniel PAUD YE 2022 [1]
Initial Rate (IP30)	114 bbl/d	116 bbl/d	77 bbl/d
IP60	108 bbl/d	112 bbl/d	75 bbl/d
Ultimate Recovery	85 Mbbl	130 Mbbl	85 Mbbl
Booked Locations	30 (29.3 net)		15 (14.3 net)
Economics[1]			
Capital (D,C & E)	$1.86 MM		
NPV10	$2.4 MM		
Payout	1.4 years		
Rate of Return	82%		
Recycle Ratio	3.6 times		

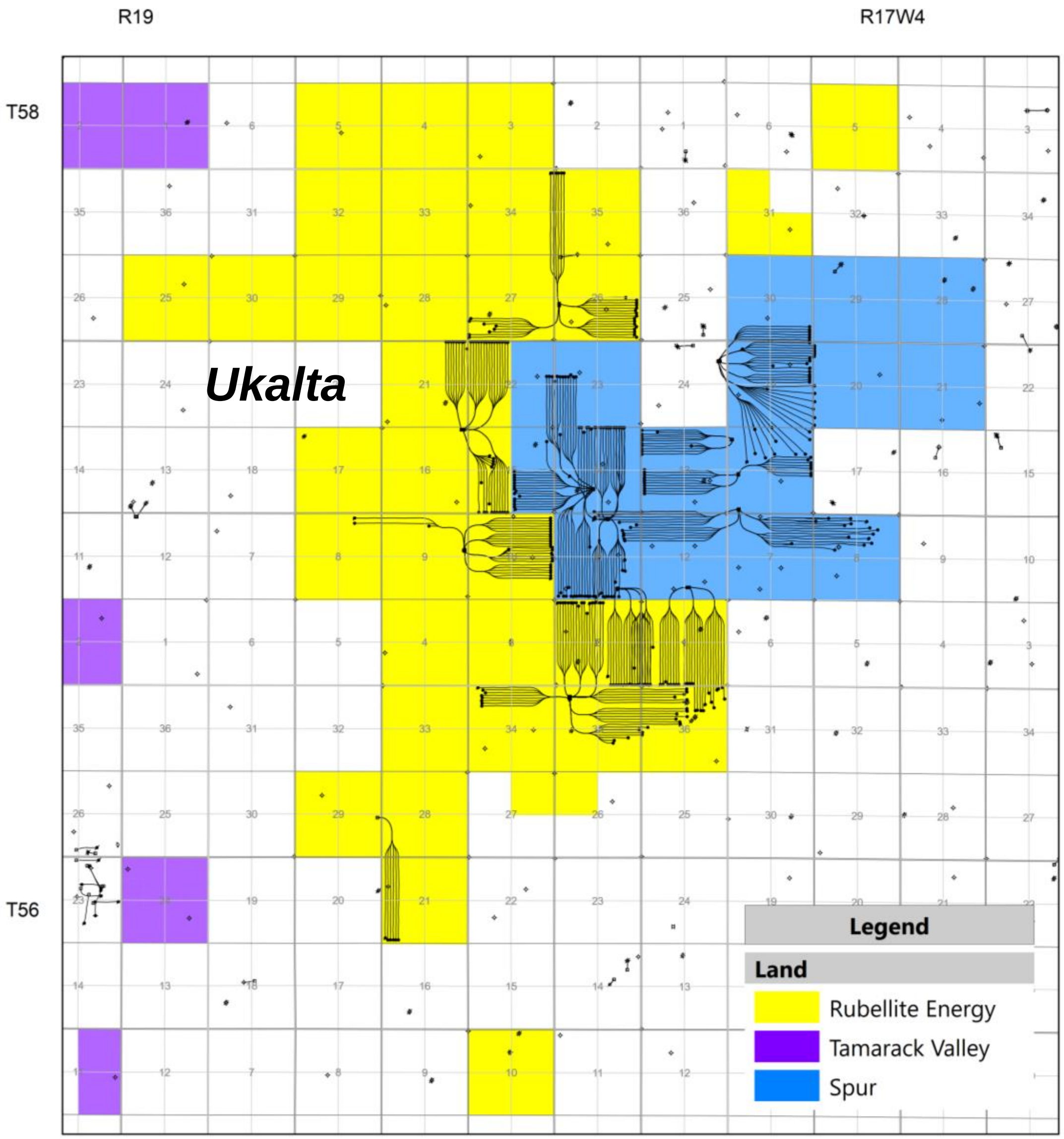


1. *Total Proved Plus Probable (P+PUD) reserve and economic parameters as per Year End 2022 McDaniel Reserve Report*

Rubellite Asset Profile | *Ukalta*

Evaluating Enhanced Recovery and Secondary Zones

Asset Map



Source: geoScout and competitor disclosures

Asset Summary

Working Interest: 100%

Q2 2023 Production: 677 bbl/d heavy oil

- 26 Primary Zone multi-laterals on sales production

2022 Strategy

- Evaluate optimal well design (number of laterals, overall length, multi-lateral wellbore placement)
- Delineate Primary Zone pool extensions
- Advance understanding of potential of 3 additional prospective zones

2022 Activity

- 11 Primary Zone HZ Development wells
- 1 Primary Zone Western Pool Extension well
- 4 Primary Zone Northeast Pool Extension wells
- 1 Northwest Step-out Vertical Evaluation well
- 1 water disposal service well

2023 Activity

- No capital activity - Monitoring production performance

Prospect Inventory

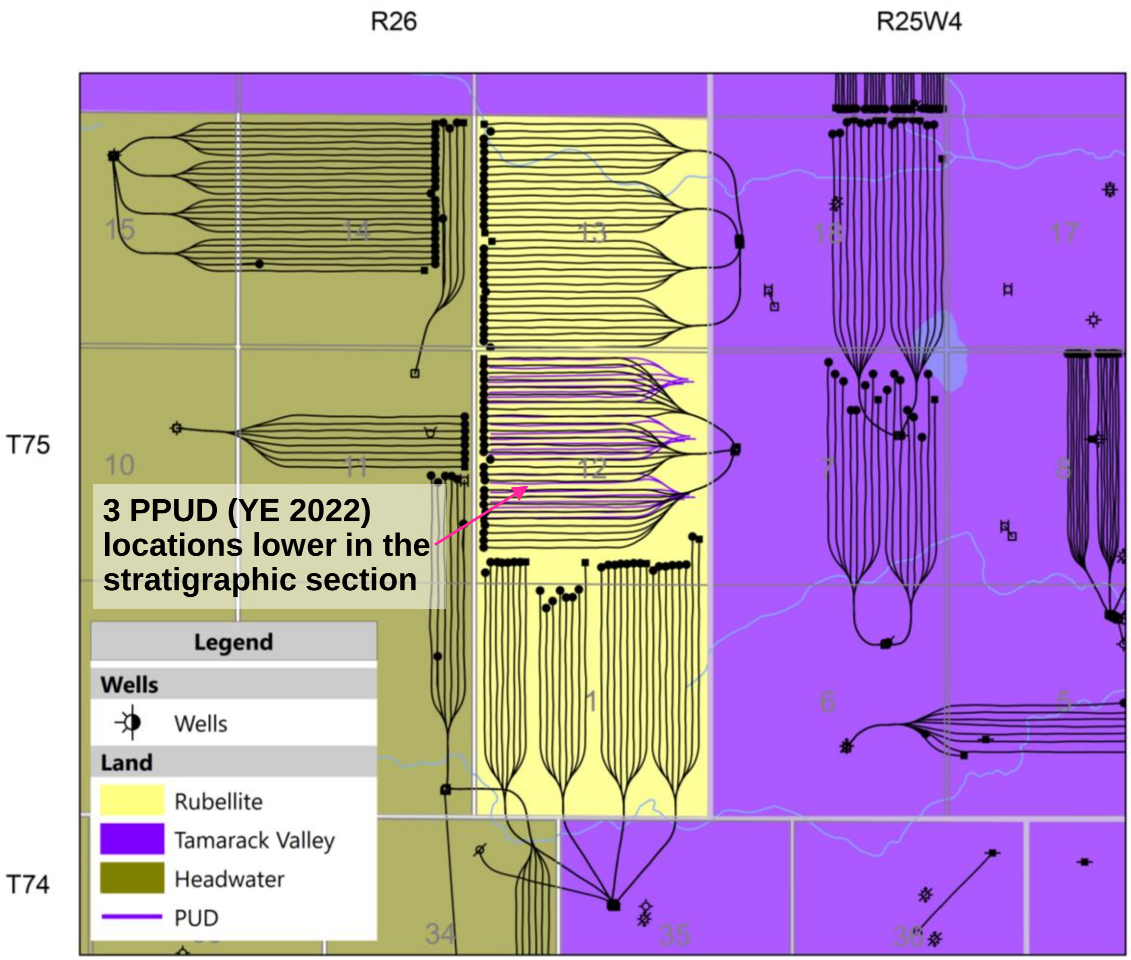
- 11 booked(1) Primary Zone HZ Development locations
- Secondary zone potential in Upper Clearwater and Clearwater channel facies

1. *Total Proved Plus Probable (P+PUD) reserve parameters as per Year End 2022 McDaniel Reserve Report*

Rubellite Asset Profile | *Marten Hills*

Secondary Recovery Schemes to Maximize Recovery and Value

Asset Map



Source: geoScout and competitor disclosures

Asset Summary

Working Interest: 30%

- 3 gross sections at 50% BPO / 30% APO WI

Q2 2023 Production[1]: 368 bbl/d heavy oil

- Converted to after payout working interest May 1, 2023

2022 Strategy

- Develop with 8 – 9 leg open hole multi-laterals
  - 1,400-1,600 m/leg (average 11,800 m/well open hole)
- Eleven (4.5 BPO / 3.3 APO net) wells on production as at Year End 2022
  - 2 (1.0 net BPO) wells onstream in Q3 2021
    - Average IP30 = 108 bbl/d; IP 60 = 105 bbl/d
  - 4 (2.0 net BPO) wells onstream in H1 2022
    - Average IP30 = 162 bbl/d; IP60 = 137 bbl/d
  - 2 (0.6 net) wells onstream in Q3 2022
    - Average IP30 = 220 bbl/d; IP60 = 212 bbl/d
  - 3 (0.9 net) wells onstream in Q4 2022
    - Average IP30 = 231 bbl/d; IP60 = 213 bbl/d

2023 Strategy

- Monitor competitor waterflood performance
- Evaluate implementation of enhanced oil recovery scheme
- Planning for drilling of 3 lower stack PPUD locations in 2024

1. *Production at Marten Hills is reported at the After Payout Working Interest for the first 6 Test Wells. Project Payout occurred in January 2023. A notice of Payout to the Farmor was issued in Q1 2023 and the Farmor elected to convert to a Working Interest. The conversion is effective May 1, 2023, subject to adjustments*

Rubellite Asset Profile | *Marten Hills*

Strong production performance from Q4 2022 drilling program

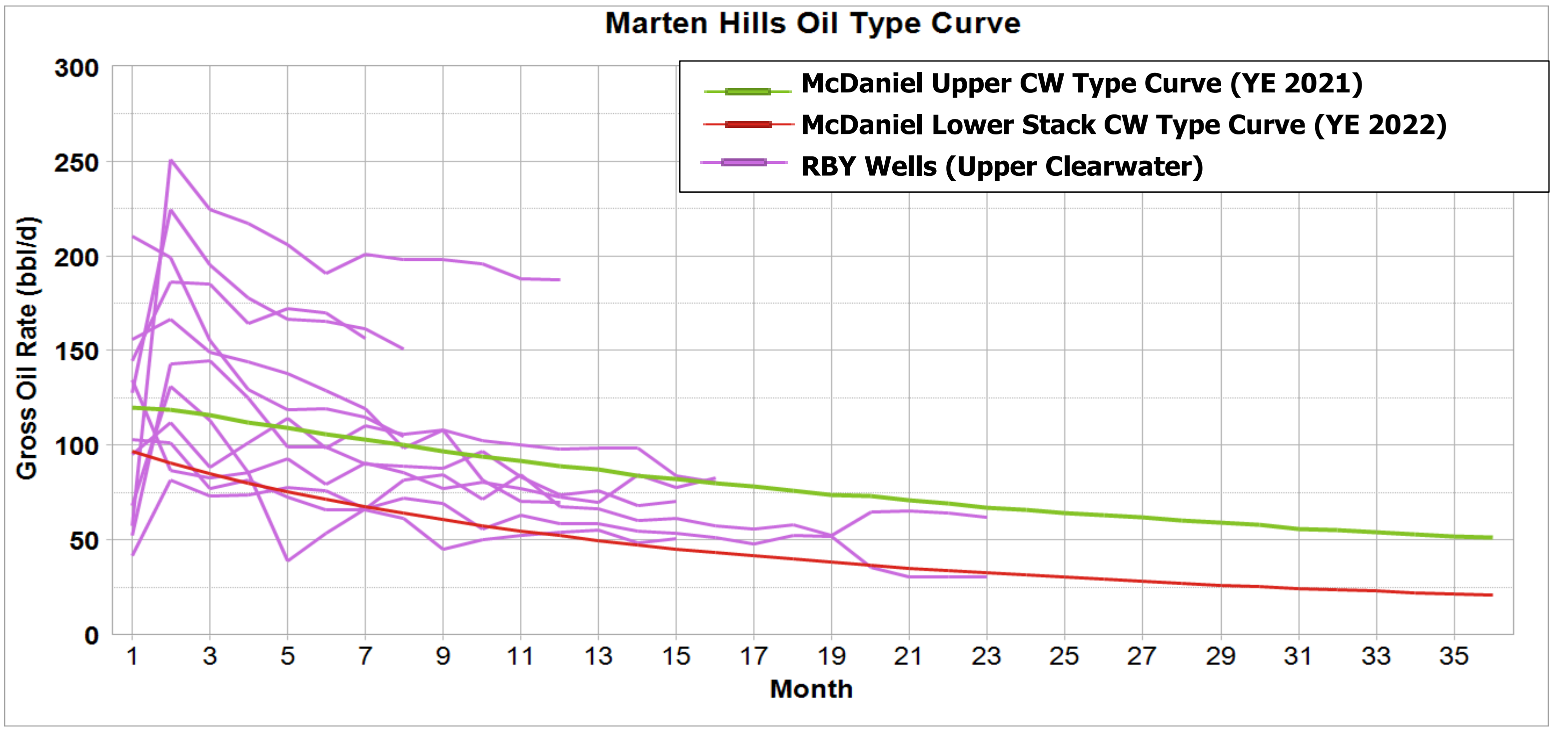
Type Curve and Production Results

Marten Hill Q4 2022 Development Wells

- 3 (0.9 net) wells drilled in Q4 2022 – 9 leg multi-laterals
  - 13-12-075-26W4: IP30 236 bbl/d; IP60 217 bbl/d; IP90 196 bbl/d
  - 12-12-075-26W4: IP30 243 bbl/d; IP60 224 bbl/d: IP90 211 bbl/d
  - 05-12-075-26W4: IP30 213 bbl/d; IP60 198 bbl/d; IP90 190 bbl/d
- Q4 2022 Drills outperforming YE 2021 Upper Clearwater Type Curve
- Future locations at a lower type curve than original wells as wells are placed lower stratigraphically for future waterflood

Type Curve Assumptions

Assumptions: Lower Stack Clearwater (8-leg multi-lateral, 12,800m)	McDaniel PPUD YE 2022 (1)
Initial Rate (IP30)	97 bbl/d
IP60	94 bbl/d
Ultimate Recovery	75 Mbbl
Locations	3 (0.9 net)

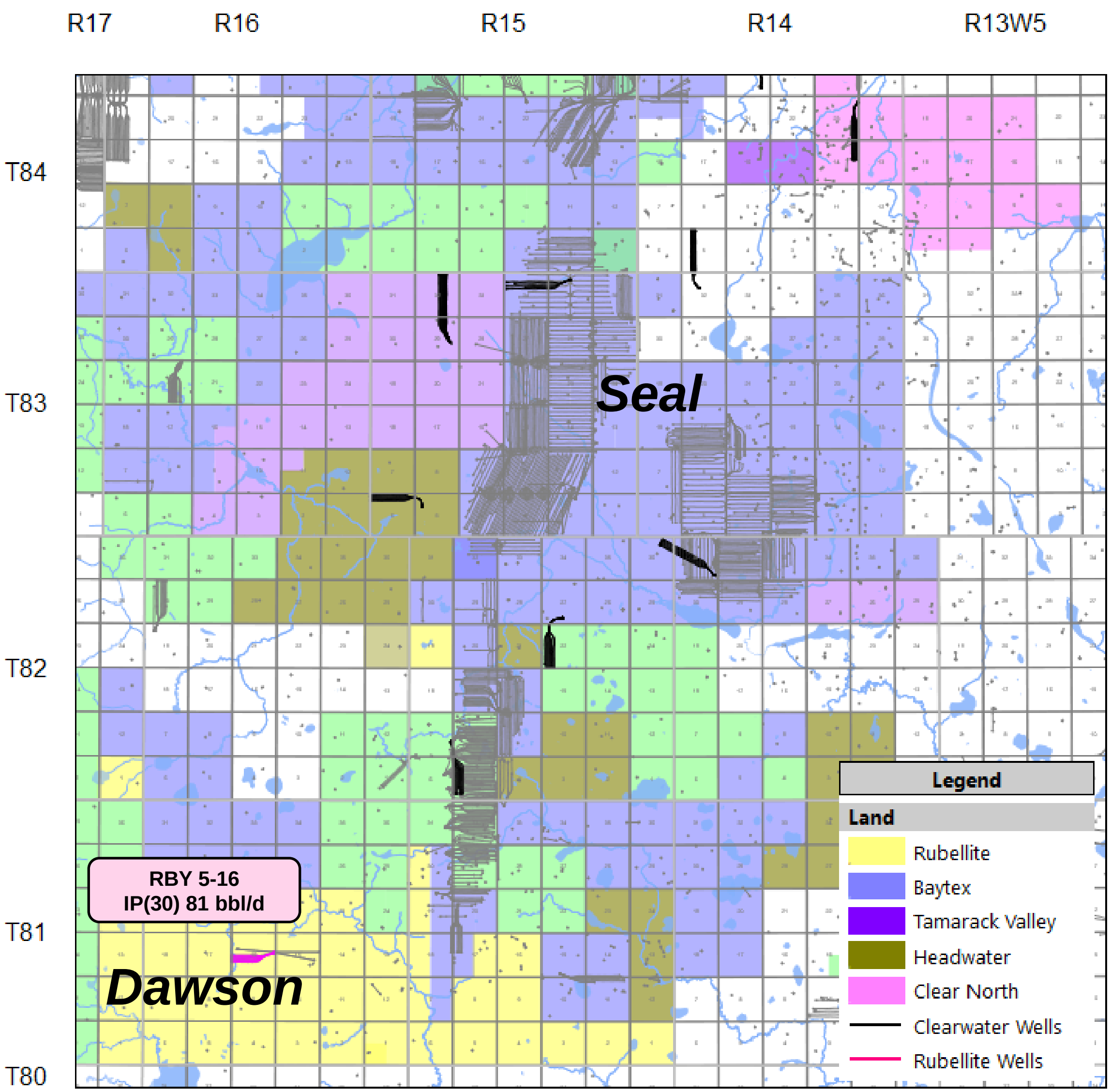


1. *Total Proved Plus Probable (P+PUD) reserve parameters as per Year End 2022 McDaniel Reserve Report*

Dawson - Northern Clearwater Exploration

Encouraging early results at Dawson

Asset Map

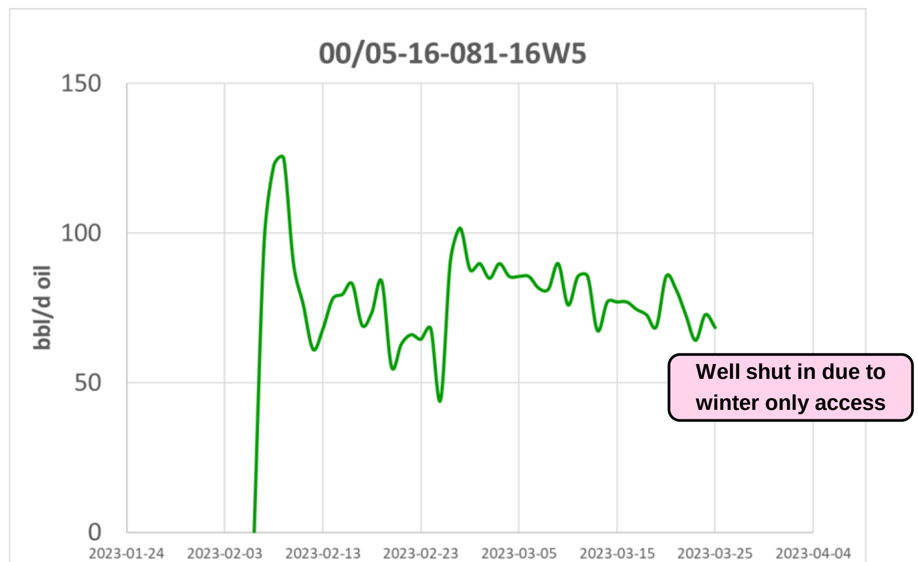


Source: GeoScout and competitor disclosures

Opportunity Summary

Dawson Exploration:

- 1 earning well (50% WI) drilled in Q1 2023
  - ~7,500m horizontal open hole
  - IP30 81 bbl/d
- 5-16 well on production in Q1 2023 for 47 days at an average rate of 80 bbls/d oil and 33% water cut before being shut in due to limited all-season access
  - Plan to re-start for production performance monitoring when frozen ground returns in December 2023
- Elected to drill second well (50% WI) to earn additional acreage in winter 23/24
  - Targeting increased length to >10,000m to improve productivity, capital efficiency and reserves



Rubellite Guidance

Development plan is funded out of Adjusted Funds Flow at current strip prices

Guidance *(Updated August 10, 2023)*

	H1 2023	2023
Development Capital Expenditures [(1)(3)] ($ MM)	$24.6	$47 - $52
Exploration Capital Expenditures [(2)(3)] ($MM)	$6.5	$7 - $13
Average Sales Production (bbl/d)	2,917	2,900 – 3,100
Heavy Oil Wellhead Differential [(4)] ($/bbl)	$5.92	$6.00 - $7.00
Royalties [(5)] (% of revenue)	9.1%	9.5% - 10.5%
Operating Costs ($/bbl)	$6.65	$6.00 - $6.50
Transportation Costs ($/bbl)	$7.90	$7.50 - $8.00
G&A ($/bbl)	$6.37	$5.50 - $6.00

1. *Q2 2023 capital expenditures include $3.2 million for inventory procurement of casing, tubulars and facilities for the remainder of 2023 drilling program; 2023 Development capital expenditures includes the drilling of 25.0 to 26.0 net horizontal multi-lateral wells*
2. *2023 Exploration capital spending includes the Q1 2023 drilling of 1 (0.5 net) multi-lateral exploratory well at Dawson and 2 (2.0 net) multi-lateral exploratory wells at Peavine as well as 3 (2.0 net) wells planned H2 2023 at Cadotte / Dawson as part of Northern Exploration program*
3. *Excludes land purchases and acquisitions*
4. *Quality differential relative to Western Canadian Select (C$/bbl)*
5. *Includes Crown, freehold and GORRs*

Development Parameters

- Single pad batteries with minimal infrastructure
- Oil sales from new wells forecast approximately two months post spud after base-oil load fluid recovery
  - Load oil from oil-based drilling mud recovered for re-use
- Arrangement to re-use roads and pipelines from historical shallow gas development to reduce incremental spending for roads and gas infrastructure
- 2023 development / step-out drilling program
  - 25 – 26 (25.0- 26.0 net) wells at Figure Lake
    - Second rig in Q4 2023 to drill 2 – 3 step outs including up to two (2.0 net) wells on the Buffalo Lake Metis Settlement lands to extend reservoir and fulfill commitment
  - No drilling planned at Ukalta or Marten Hills in 2023

Exploration Activities

- Identifying new fairways and zones of interest
- Advancing evaluation of Northern Clearwater exploratory acreage
  - Dawson prospect
    - *1 successful multi-lateral well drilled in Q1 2023*
    - *Election made to drill a second 50% earning well before April 1, 2024*
  - Peavine prospect
    - *2 multi-lateral wells drilled in Q1 2023*
    - *Monitoring competitor wells to inform further drilling elections*
  - Cadotte prospect
    - *Access constrained; Targeting winter 2023/2024*
  - Forecast $7 to $13 million total spending in 2023

Line of sight to sustainable free funds flow - Timing dependent on commodity prices, continued infill drilling success at Figure Lake and scale and timing of exploration program

Risk Management

WCS price protection on an average of 1,600 bbl/d in H2 2023 at ~$80.84 Cdn/bbl

Risk Management Philosophy and Strategy

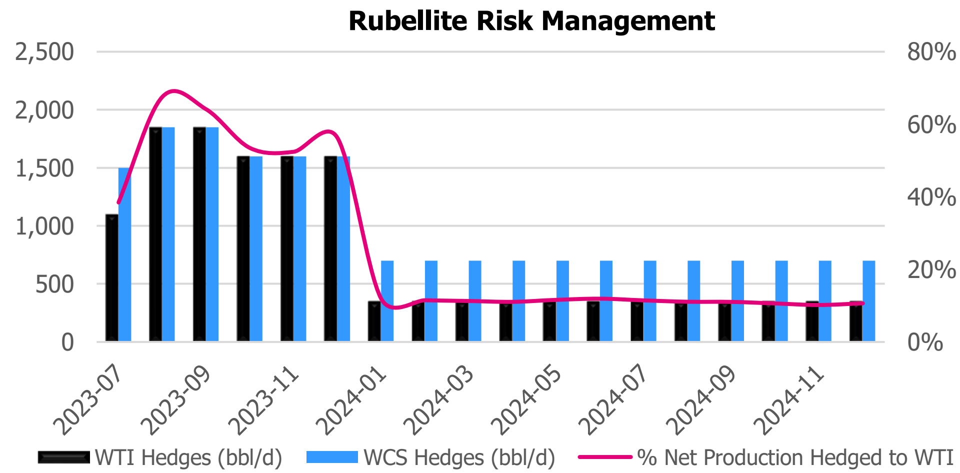
- Physical forward sales contracts and financial derivatives used to:
  - Increase certainty in adjusted funds flow
  - Manage the balance sheet
  - Ensure adequate funding for capital programs
  - Lock in investment returns
  - Take advantage of perceived anomalies in commodity markets

Execution Strategy:

- During rapid production growth phase, targeting commodity price protection on ~50% of forecast volumes
- Once critical mass production levels achieved, strategy will revert to focus on protection of maintenance capital spending and investment returns, with a higher risk tolerance for commodity market fluctuations

Current WTI and WCS hedge positions *(as at Aug 10, 2023)*

	Q3 2023	Q4 2023	Cal 24
WTI USD/bbl Swap Volume (bbl/d) ($USD/bbl)	1,267 $77.02	1,500 $76.83	- -
WTI CAD/bbl Swap Volume (bbl/d) ($CAD/bbl)	333 $99.51	100 $101.50	350 $100.80
WCS USD/bbl Swap Volume (bbl/d) ($USD/bbl)	1,300 ($16.95)	1,100 ($17.31)	- -
WCS CAD/bbl Swap Volume (bbl/d) ($CAD/bbl)	433 ($17.68)	500 ($19.49)	700 ($20.50)
CAD/USD FX Swap Notional amount ($USD/quarter) ($CAD/$USD) ($CAD/quarter)	$6,000,000 $1.3527 $8,116,350	$6,000,000 $1.3527 $8,116,350	- - -



2023 hedging program to stabilize adjusted funds flow and protect capital investment during production ramp-up phase

ESG Excellence

Strong ESG performance driven by living our values

Experienced Management and Independent Board of Directors

Cost-effectively managed under a Management and Operating Services Agreement with Perpetual

Overview of MSA with Perpetual

- Full overlap of Perpetual and Rubellite Executive Officers
  - No Rubellite-only employees
- Proportionate sharing of people, office and technology costs based on relative production split
  - 2022 80% Perpetual / 20% Rubellite
  - 2023 expected to be ~70% Perpetual / 30% Rubellite
  - MSA cap removed effective June 1, 2023
- Rubellite has ~$2.0 million/year in unique software, professional fees and other public company / corporate costs
- G&A gradually ramps up with production to ~$6.5 million per year in 2023 but will decline on a per boe basis as production grows
- Strong Governance embedded in MSA
  - Annual renewal process
  - Executive compensation oversight
  - Quarterly Board oversight of business development opportunities and Joint Corporate Opportunities Policy compliance

Independent Board of Directors (Non-Executive)

Tamara MacDonald, *Independent Director*

- Director of Spartan Delta Corp. and Southern Energy Corp.
- Former Senior Vice President, Corporate and Business Development of Crescent Point Energy from 2016 to 2018
- Prior thereto Vice President, Land and Corporate Development of Crescent Point from 2004 to 2016

Bruce Shultz, *Independent Director*

- Former President and CEO of Huron Resources Corp; sold to a private oil and gas producer in 2020
- Prior thereto President and CEO of Huron Energy Corp; sold to a publicly traded oil and gas producer in 2012
- Prior thereto President and CEO of Rubicon Energy Corporation; sold to a publicly traded oil and gas producer in 2003

Holly Benson, *Independent Director*

- CA, Oil and Gas audit specialization with E&Y
- Former Vice President, Finance & CFO of Peters & Co. Limited from 1999 to December 31, 2020
- Member of the Financial and Operations Advisory Section (FOAS) of the Industry Regulatory Organization of Canada (IIROC) and the FOAS Executive, including a term as Chair
- IIROC board member since January 2015 and member of Finance, Audit and Risk Committee

Majority independent directors to establish strong governance
Cost effectively managed under management and operating services agreement (MSA) with Perpetual

Creating Differentiated Value for Shareholders

Fully funded growth opportunity in the prolific Clearwater play

Robust Organic Production Growth Profile

Expanding Pure Play Clearwater Asset Base

Conservative Capitalization and Risk Mitigation

Fully Funded Development Unlocking Free Funds Flow

Management Alignment and ESG Excellence

Additional Information

Sue Riddell Rose, President & CEO
Ryan Shay, Vice President, Finance & CFO

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Calgary, Alberta Canada T2P 3H5

Slide Notes

Slide 1

1. Current shares outstanding as at August 9, 2023, 2.7 million share awards outstanding and 4.0 million share purchase warrants (5-year term; $3.00 exercise price owned by Perpetual Energy)
2. Enterprise value is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
3. Market capitalization is non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
4. Market capitalization is calculated based on basic common shares outstanding as at August 9, 2023 and a share price of $2.05
5. Net debt is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
6. Copies of the Company's credit agreements are available under the Company's profile on SEDAR+ website at www.sedarplus.ca

Slide 2

1. See "Drilling Locations" in the Advisories
2. IRR is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
3. Payout is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
4. Adjusted funds flow is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
5. Free funds flow is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
6. Cash costs is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories

Slide 3

1. ROR is a non-GAAP ratio that was provided by a Third Party. See "Third Party Information" in the Advisories and "Non-GAAP and Other Financial Measures" in the Advisories
2. Payout is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories

Slide 4

1. See "Drilling Locations" in the Advisories
2. All the land and the drilling locations shown are net to Rubellite's working interest. See "Drilling Locations" in the Advisories
3. Payout is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
4. Before Payout and After Payout is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories

Slide Notes (continued)

Slide 5

1. "Net asset value" is non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
2. "Operating netback per boe" is determined by deducting royalties, production and operating expenses, and transportation costs form oil and natural gas revenue, as determined in accordance with IFRS, divided by the Company's total sales oil production
3. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
4. "McDaniel Reserve Report" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2022 and a preparation date of March 9, 2023
5. The "McDaniel Type Curve" assumptions and economics are based on the Total Proved Plus Probable Undeveloped reserves contained in the McDaniel Reserve Report using the "Consultants Average Jan 1, 2023 Pricing" as disclosed in the Company's Annual Information Form which is available under the Company's profile on SEDAR+ at www.sedarplus.ca
6. "PUD" means locations that have been booked in the proved undeveloped category in the McDaniel Reserve Report
7. "PPUD" means locations that have been booked in the proved plus probable undeveloped category in the McDaniel Reserve Report
8. Net debt is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories

Slide 6

1. See "Drilling Locations" in the Advisories

Slide 7

1. See "Drilling Locations" in the Advisories
2. Capital is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories

Slide 8

1. See "Drilling Locations" in the Advisories

Slide Notes (continued)

Slide 9

1. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
2. “McDaniel Reserve Report” means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2022 and a preparation date of March 9, 2023
3. The “McDaniel Type Curve” assumptions and economics are based on the Total Proved Plus Probable Undeveloped reserved contained in the McDaniel Reserve Report using the “Consultants Average Jan 1, 2023 Pricing” as disclosed in the Company’s Annual Information Form which is available under the Company’s profile on SEDAR+ at www.sedarplus.ca
4. “PUD” means locations that have been booked in the proved undeveloped category in the McDaniel Reserve Report
5. “PPUD” means locations that have been booked in the proved plus probable undeveloped category in the McDaniel Reserve Report
6. “PAUD” means locations that have been booked in the probable undeveloped category in the McDaniel Reserve Report
7. “Ultimate Recovery” is defined as the estimated ultimate recoverable reserves as recognized in the McDaniel reserve report for the year ending December 31, 2022
8. Payout, rate of return and recycle ratio are non-GAAP ratios. See “Non-GAAP and Other Financial Measures” in the Advisories

Slide 10

1. See “Drilling Locations” in the Advisories
2. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
3. “McDaniel Reserve Report” means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2022 and a preparation date of March 9, 2023
4. The “McDaniel Type Curve” assumptions and economics are based on the Total Proved Plus Probable Undeveloped reserved contained in the McDaniel Reserve Report using the “Consultants Average Jan 1, 2023 Pricing” as disclosed in the Company’s Annual Information Form which is available under the Company’s profile on SEDAR+ at www.sedarplus.ca
5. “PPUD” means locations that have been booked in the proved plus probable undeveloped category in the McDaniel Reserve Report
6. Payout is a non-GAAP ratio. See “Non-GAAP and Other Financial Measures” in the Advisories
7. Before Payout and After Payout is a non-GAAP ratio. See “Non-GAAP and Other Financial Measures” in the Advisories

Slide 11

1. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
2. “McDaniel Reserve Report” means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2022 and a preparation date of March 9, 2023
3. The “McDaniel Upper CW Type Curve” assumptions and economics are based on the Total Proved Plus Probable Undeveloped reserved contained in the 2021 McDaniel Reserve Report
4. The “McDaniel Lower Stack CW Type Curve” assumptions and economics curve was established in the McDaniel Reserve Report with an effective date of December 31, 2022
5. “PPUD” means locations that have been booked in the proved plus probable undeveloped category in the McDaniel Reserve Report
6. “Ultimate Recovery” is defined as the estimated ultimate recoverable reserves as recognized in the McDaniel reserve report for the year ending December 31, 2022

Slide Notes (continued)

Slide 12

1. See "Drilling Locations" in the Advisories

Slide 13

1. See "Drilling Locations" in the Advisories
2. Development and exploration capital expenditures is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
3. Heavy oil wellhead differential is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
4. "Royalties per boe" is comprised of royalties, as determined in accordance with IFRS, divided by the Company's total sales oil production
5. "Operating expense per boe" is comprised of production and operating expense, as determined in accordance with IFRS, divided by the Company's total sales oil production
6. "Transportation cost per boe" is comprised of transportation cost, as determined in accordance with IFRS, divided by the Company's total sales oil production
7. "General and administrative per boe" is comprised of general and administrative costs, as determined in accordance with IFRS, divided by the Company's total sales oil production
8. Payout is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
9. Before Payout and After Payout is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories
10. Free funds flow is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories

Slide Notes (continued)

Slide 14

1. Prices reported are the weighted average prices for the period
2. Western Canadian Select ("WCS")
3. Hedge positions current to August 10, 2023. Full hedge positions by product are as follows:

As at August 10, 2023, the Company had entered into the following commodity risk management contracts:

Commodity	Volumes sold *(bbl/d)*	Term	Reference/Index	Contract Traded Bought/sold	Average Price *($/bbl)*
Crude Oil	200 bbl/d	Jul 1 – Dec 31, 2023	WCS Differential (CAD$/bbl)	Swap – sold	($17.75)
Crude Oil	250 bbl/d	Aug 1 - Sept 30, 2023	WCS Differential (CAD$/bbl)	Swap - sold	($16.07)
Crude Oil	100 bbl/d	Aug 1 - Dec 31, 2023	WCS Differential (CAD$/bbl)	Swap - sold	($21.50)
Crude Oil	200 bbl/d	Oct 1 - Dec 31, 2023	WCS Differential (CAD$/bbl)	Swap - sold	($20.23)
Crude Oil	700 bbl/d	Jan 1 - Dec 31, 2024	WCS Differential (CAD$/bbl)	Swap - sold	($20.50)
Crude Oil	450 bbl/d	Jul 1 - Sep 30, 2023	WCS Differential (USD$/bbl)	Swap - sold	($15.94)
Crude Oil	850 bbl/d	Jul 1 - Dec 31, 2023	WCS Differential (USD$/bbl)	Swap - sold	($17.48)
Crude Oil	250 bbl/d	Oct 1 - Dec 31, 2023	WCS Differential (USD$/bbl)	Swap - sold	($16.75)
Crude Oil	1,100 bbl/d	Jul 1 - Dec 31, 2023	WTI (USD$/bbl)	Swap - sold	$77.26
Crude Oil	250 bbl/d	Aug 1 - Sept 30, 2023	WTI (USD$/bbl)	Swap - sold	$75.44
Crude Oil	400 bbl/d	Oct 1 - Dec 31, 2023	WTI (USD$/bbl)	Swap - sold	$75.65
Crude Oil	400 bbl/d	Aug 1 - Sept 30, 2023	WTI (CAD$/bbl)	Swap – sold	$99.01
Crude Oil	100 bbl/d	Aug 1 - Dec 31, 2023	WTI (CAD$/bbl)	Swap - sold	$101.50
Crude Oil	350 bbl/d	Jan 1 - Dec 31, 2024	WTI (CAD$/bbl)	Swap - sold	$100.80

Foreign exchange risk management

As at August 10, 2023, the Company entered into the following foreign exchange risk management contracts:

Contract	Notional amount	Term	Price (CAD$/US$)
Average rate forward (CAD$/US$)	$2,000,000 US$/month	Jul 1 – Dec 31, 2023	1.3527

Slide 16

1. G&A per BOE is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories

Slide 17

1. Free funds flow is a non-GAAP ratio. See "Non-GAAP and Other Financial Measures" in the Advisories

Advisories

General

The information contained in this presentation does not purport to be all-inclusive or to contain all information that prospective investors may require. Prospective investors are encouraged to conduct their own analysis and reviews of the Company and of the information contained in this presentation. Prospective investors should consult their own professional advisors to assess their potential investment in the Company and before making an investment decision. An investment in the Common Shares is subject to a number of risks that should be considered by a prospective investor. In this presentation, all amounts are in Canadian dollars, unless otherwise indicated. Any graphs, tables or other information in this presentation demonstrating the historical performance of the Company or of any other entity are intended only to illustrate past performance and are not necessarily indicative of future performance of the Company. Certain totals, subtotals and percentages may not reconcile due to rounding. See also "Forward-Looking Information" and "Non-GAAP and Other Financial Measures" in the Management's Discussion and Analysis for the period ended June 30, 2023 ("June 30, 2023 MD&A") and year ended December 31, 2022 ("December 31, 2022 MD&A" and "Risk Factors" in the Annual Information Form for the year ended December 31, 2022).

Non-GAAP and Other Financial Measures

Throughout this presentation 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 operating activities, and cash flow from investing activities, as indicators of Rubellite's performance. See *"Non-GAAP and Other Financial Measures"* in the June 30, 2023 MD&A and December 31, 2022 MD&A for further information on the definition, calculation and reconciliation of these measures.

Non-GAAP Financial Measures

"Enterprise value" is equal to net debt plus the market value/capitalization 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 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.

"Market capitalization" is calculated by multiplying the current shares outstanding by the market price. The Company considers market capitalization as an important measure as it is part of the calculation of enterprise value which normalizes the market value of the Company's shares for its capital structure.

"Net debt" is calculated by deducting any borrowing from adjusted working capital. Adjusted working capital is current assets less current liabilities, adjusted for the removal of the current portion of risk management contracts. Rubellite uses net debt as an alternative measure of outstanding debt. Management considers net debt and adjusted working capital as important measures in assessing the liquidity of the Company.

"Adjusted working capital" deficiency or surplus includes total current assets and current liabilities excluding short-term risk management contract assets and liabilities related to the Corporation's risk management activities.

"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 since the Company believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of Rubellite's operating areas. Expenditures on decommissioning obligations are managed through the capital 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 and meet its financial obligations.

"Free funds flow" is calculated by taking adjusted funds flow and subtracting capital expenditures, excluding acquisitions and dispositions. Management uses certain industry benchmarks, such as free funds flow, to analyze financial and operating performance. Management believes that free funds flow provides a useful measure to determine the Company's ability to improve returns and manage the long-term value of the business.

Advisories (continued)

Non-GAAP and Other Financial Measures (continued)

“Capital expenditures”, “Capital”, “E&D capital expenditures”, “Development capital expenditures”, or “Exploration capital expenditures” are used to measure its capital investments compared to the Company’s annual capital budgeted expenditures. Rubellite’s capital budget excludes acquisition and disposition activities.

“NPV10%” is the net present value (net of capital expenditures) of the operating income of a well from the McDaniel’s report discounted at a 10% discount rate.

Net Asset Value ("NAV") is total proved plus probable reserves as per the McDaniel reserve report as at December 31, 2022, plus independently verified third party valuation of undeveloped lands, less net debt. This measure is used to show the net asset value of the Company at a point in time under which the reserves are produced at forecast future prices and costs.

Non-GAAP Financial Ratios

“Cash costs” is calculated as the total of production and operating expenses, transportation costs and general and administration costs (G&A), divided by the Company’s total sales oil production. Management considers cash costs as an important measure to evaluate the Company’s operational performance as it demonstrates efficiency of operations.

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

“IRR”, or internal rate of return, is a rate of return measure used to compare the profitability of an investment and represents the discount rate at which the net present value of costs equals the net present value of the benefits. The higher a project's IRR, the more desirable the project.

“ROR”, or rate of return, is a rate of return measure used to compare the profitability of an investment and represents the discount rate at which the net present value of costs equals the net present value of the benefits. The higher the ROR, the more desirable the project.

“Operating netback” is determined by deducting royalties, production and operating expenses, and transportation costs from oil and natural gas revenue. Operating netback is also calculated on a per boe basis using total production sold in the period.

“Recycle ratio” is determined by dividing the operating netback per boe by F&D costs.

“F&D” costs is used as a measure of capital efficiency. The F&D cost calculation includes all capital expenditures for the booked location in the McDaniel’s report divided by the total proved plus probable reserves booked to that location in the McDaniel’s report.

“Payout” is calculated as the time at which a well or project’s cumulative operating netback equals total capital expenditures.

“Before payout” or “BPO” is the working interest before the point in time when the well has recovered from production all costs stated in the underlying farmout or arrangement.

“After payout” or “APO” is the working interest after the point in time when the well has recovered from production all costs stated in the underlying farmout or arrangement.

“Operating costs” is comprised of production and operating expense, as determined in accordance with IFRS, divided by the Company’s total sales oil production.

“Transportation costs” is comprised of transportation expense, as determined in accordance with IFRS, divided by the Company’s total sales oil production.

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

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

Advisories

Forward Looking Information

Certain information in this presentation including management's assessment of future plans and operations, and including, without limitation the information contained under the headings "Investment Highlights", "Rubellite Guidance", "Rubellite Management", "Rubellite Asset Profile" and "Creating Differentiated Value for Shareholders" 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; expectations as to drilling activity plans and the benefits to be derived from such drilling including the production growth and ability for the business plan to be fully funded; expectations respecting Rubellite's future exploration, development and drilling activities and Rubellite's business plan; expectations respecting Rubellite's ability to obtain sustainable free funds flow and the use of free funds flow for accelerated organic growth, additional exploration activities, acquisitions and returns to shareholders; and the information and statements contained under the heading "Rubellite Guidance".

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 presentation. In particular and without limitation of the foregoing, material factors or assumptions on which the forward-looking information in this presentation is based include: anticipated growth in inventory and funds flow; the successful operation of the Clearwater 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); Rubellite's ability to operate under the management of Perpetual pursuant to the management and operating services agreement; 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); 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; cybersecurity breaches; and the ongoing and future impact of pandemics (including COVID-19); and the war in Ukraine and related sanctions on commodity prices and the global economy, among others.

Undue reliance should not be placed on forward-looking information, which is not a guarantee of performance and is subject to a number of risks or uncertainties, including without limitation those described herein and under "Risk Factors" in Rubellite's Annual Information Form and MD&A for the year ended December 31, 2022 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.

Oil and Gas Industry Metrics

This presentation contains certain oil and gas 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.

Initial Production Rates

Any references in this presentation to initial production rates, including IP30 and IP60 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 the time.

Advisories (continued)

Drilling Locations

This presentation discloses Rubellite's estimated drilling locations in two categories: (i) booked locations and (ii) unbooked development / step-out locations. Booked locations are proved and probable locations, are derived from the McDaniel Reserve Report and account for drilling locations that have associated proved and/or probable reserves, as applicable, and have not yet been drilled. Unbooked locations are internal estimates based on Rubellite's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent ad prospective). Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. Unbooked development and step-out locations are located within the mapped outline of existing proven Clearwater zones where economic production has been stablished.

Of the approximately 192 (189.9 net) drilling locations identified herein 39 (36.9 net) are proved locations at year-end 2022, 20 (20 net) are undrilled probable locations at year-end 2022 and 153 (153 net) are unbooked development / step-out locations.

There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Reserve Estimates

The reserves estimates contained in this presentation are as at December 31, 2022 and are based on based on an independent reserves evaluation report prepared by McDaniel & Associates Consultants Ltd. in accordance with NI 51-101. It should not be assumed that the present worth of estimated future net revenues represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of our crude oil reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil reserves may be greater than or less than the estimates provided herein. All future net revenues are estimated using forecast prices, arising from the anticipated development and production of our reserves, net of the associated royalties, operating costs, development costs, and decommissioning obligations and are stated prior to provision for finance and general and administrative expenses. Future net revenues have been presented on a before tax basis. Estimated values of future net revenue disclosed herein do not represent fair market value. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. The estimated values of future net revenue disclosed in this news release do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material. The reserve data provided in this Presentation presents only a portion of the disclosure required under NI 51-101. Further information is contained in the Company's Annual Information Form for the year ended December 31, 2022 which is available under the Company's profile on SEDAR+ at www.sedarplus.ca.

Advisories (continued)

Third Party Information

This presentation includes market, industry and economic data which was obtained from various publicly available sources and other sources believed by Rubellite to be true. Although Rubellite believes it to be reliable, it has not independently verified any of the data from third party sources referred to in this presentation or analyzed or verified the underlying reports relied upon or referred to by such sources or ascertained the underlying economic and other assumptions relied upon by such sources. Rubellite believes that its market, industry and economic data is accurate and that its estimates and assumptions are reasonable, but there can be no assurance as to the accuracy or completeness thereof. The accuracy and completeness of the market, industry and economic data used throughout this presentation are not guaranteed and Rubellite makes no representation as to the accuracy of such information

BOE Volume Conversions

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

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

bbl	barrels
bbl/d	barrels per day
boe	barrels of oil equivalent
MMboe	million barrels of oil equivalent