Rubellite Energy Inc.

Corporate Overview

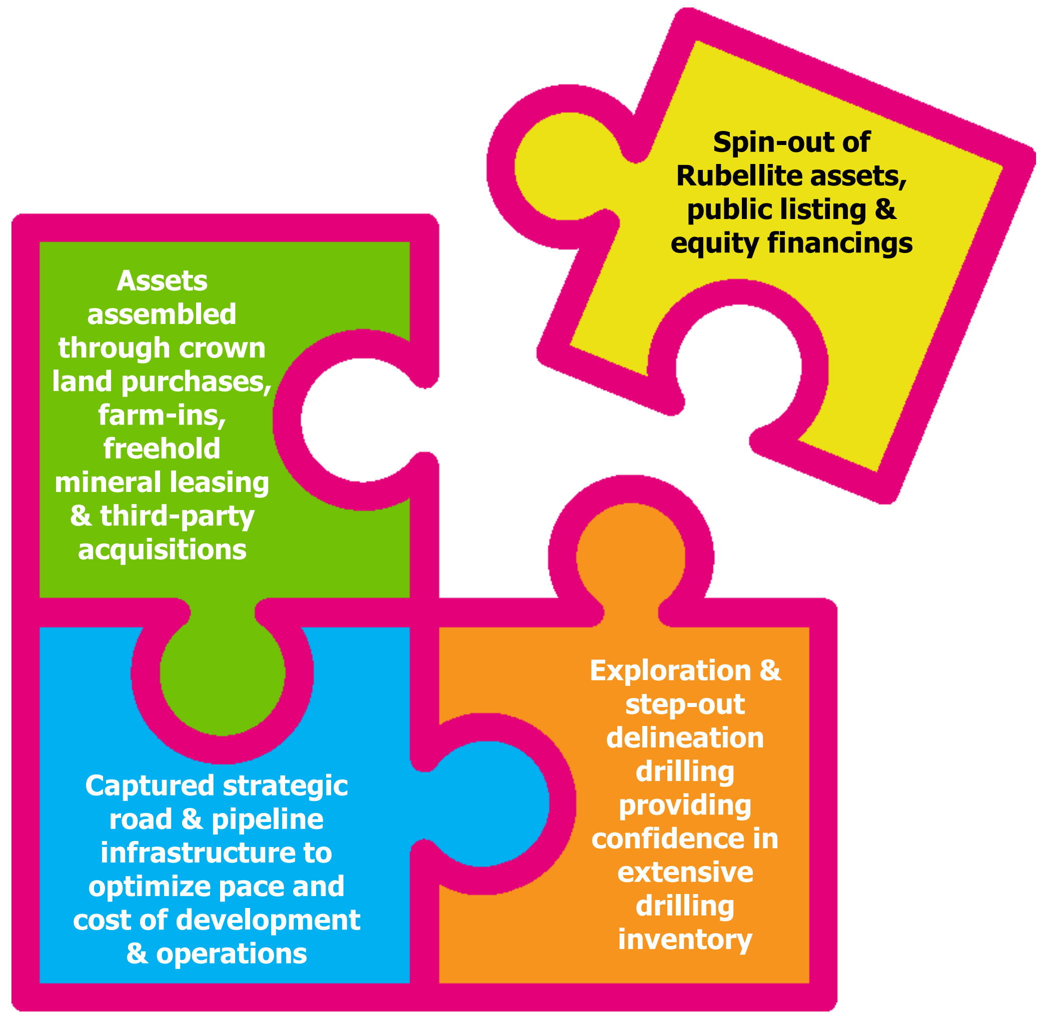
March 14, 2024

Corporate Profile

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

Since inception in 2021, Rubellite has grown from 350 bbl/d to >4,500 bbl/d and assembled access to 530 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") – Fully Back-stopped
  - 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)	62.5 MM
Market Capitalization(2)	$148.6 MM
Net Debt (December 31, 2023)	$51.0 MM
Enterprise Value	$199.6 MM
Insider Ownership	~37.5%

1. *70.1 MM fully diluted including 4.0 MM Share Purchase Warrants (owned by Perpetual)*
2. *TSX:RBY March 13, 2024 closing price of $2.38/share*

Investment Highlights

Robust growth opportunity in the prolific Clearwater play

RUBELLITE ENERGY

Expanding Pure Play Clearwater Asset Base	▪ Growth-focused, pure play Clearwater E&P company ▪ Access to over 530 net sections of prospective Clearwater lands ▪ 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 4,209 bbl/d (Q4 2023 sales) ▪ Highly profitable, full cycle IRRs with attractive payout periods at current strip prices ▪ ~240 defined Development / Step-out drilling locations ▪ 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 ~$19.00 to $20.50/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	▪ $57 MM bank credit facility ▪ Risk management with hedging to protect capital investment plans and returns during growth ramp up ▪ 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 ~37.5% ▪ Independent board oversight and strong corporate culture ▪ 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

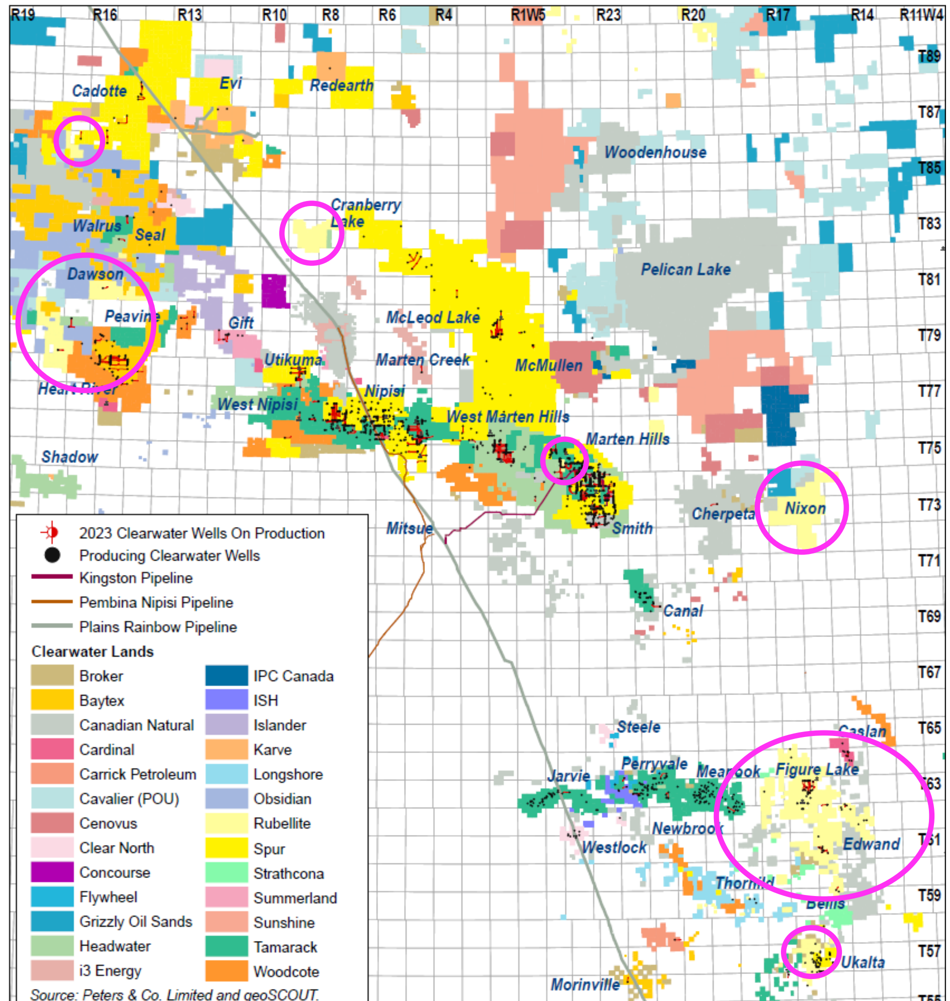
Amongst the best single well economics of any play in North America

Clearwater Play Evolution

- Since 2017, close to 1,600 wells have been drilled, growing play production from nil to >130,000 bbl/d by year-end 2023
  - ~75% of production at Marten Hills and Nipisi
  - Additional pools proven to the north at Peavine, Seal, Cadotte & McLeod; 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 Fall 2023 estimates based on US$75/B WTI and C$3.38/Mcf AECO prices
Rate of Return (ROR) calculated as NPV10 / Initial Capital Spend

Clearwater Play

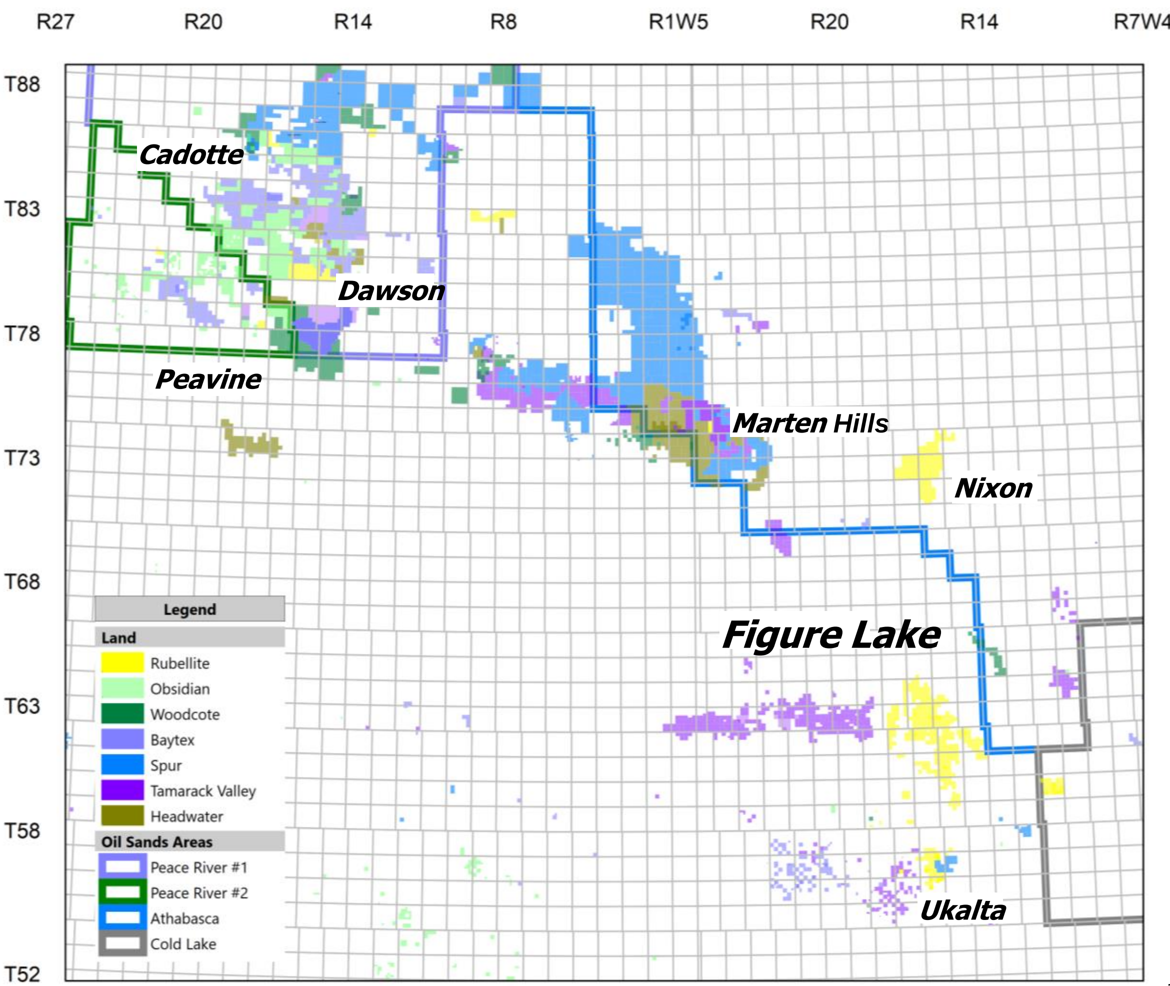


Early development of Clearwater Play focused on Marten Hills and Nipisi
Numerous new areas within the Clearwater fairway proving to be highly economic

Rubellite Asset Profile

477 net sections of prospective land; ~240 development / step-out Clearwater locations

Asset Map



Source: geoScout and competitor disclosures

Asset Summary

Area	Land (net sections)[1]	Well Count (net producing)[2]	Production Q4 2023 (bbl/d)[3]
Figure Lake/Edwand	243.1	59.0	3,400
Ukalta	34.0	26.0	534
Marten Hills[3]	0.9	3.3	272
Northern Exploration[1)(3]	53.8	0.0	3
Other Exploration[3]	145.3	3.0	-
TOTAL	**477.1**	**91.3**	**4,209**

Production:

- Q4 2023 sales production of 4,209 bbl/d
- Q1 2024 production guidance of 4,450 – 4,500 bbl/d

Reserves[4]: Total proved plus probable of 16.0 MMbbl at YE 2023

Property Status:

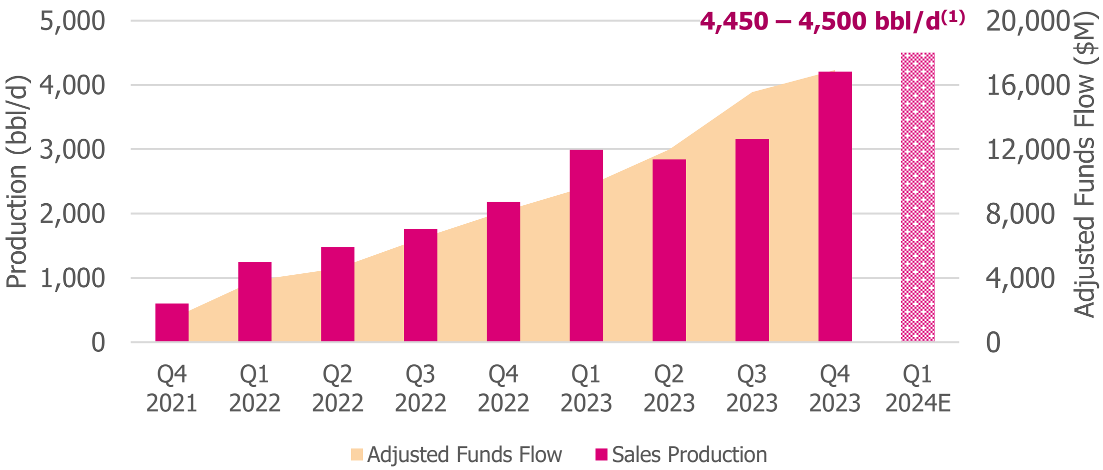
- ***Marten Hills*** - Developed on primary; Advancing secondary recovery
- ***Ukalta -*** Focus on optimization
- ***Figure Lake / Edwand*** - Development and Step-out delineation ongoing
- ***Northern Exploration*** - De-risking prospect at Dawson
- ***Other Exploration*** – New opportunity at Nixon; Other prospects in various stages of land capture & assessment

1. *477.1 net sections After Payout working interests includes option lands and farm-in exploratory lands at after payout working interest as at March 14, 2024.*
2. *Well count contributing to production during Q4 2023 was 99 gross (91.3 net APO)*
3. *100% conventional heavy crude. Other Exploration volumes included in Figure Lake production.*
4. *Total Proved Plus Probable (TPP) reserves (Gross Working Interest before royalties) as per Year End 2023 McDaniel Reserve Report.*

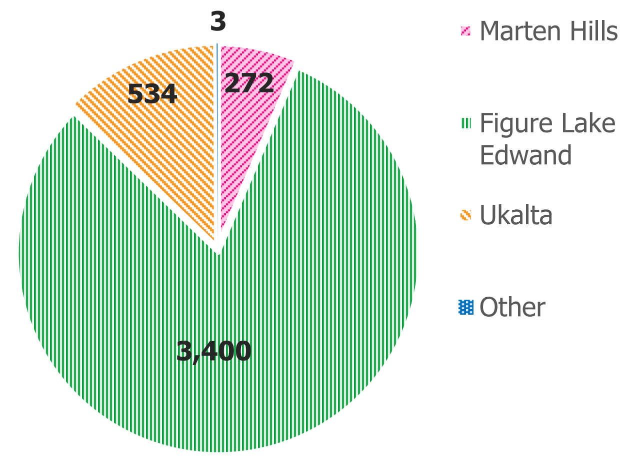
Corporate Performance

Operational Momentum Continues

Adjusted Funds Flow and Sales Production (bbl/d)

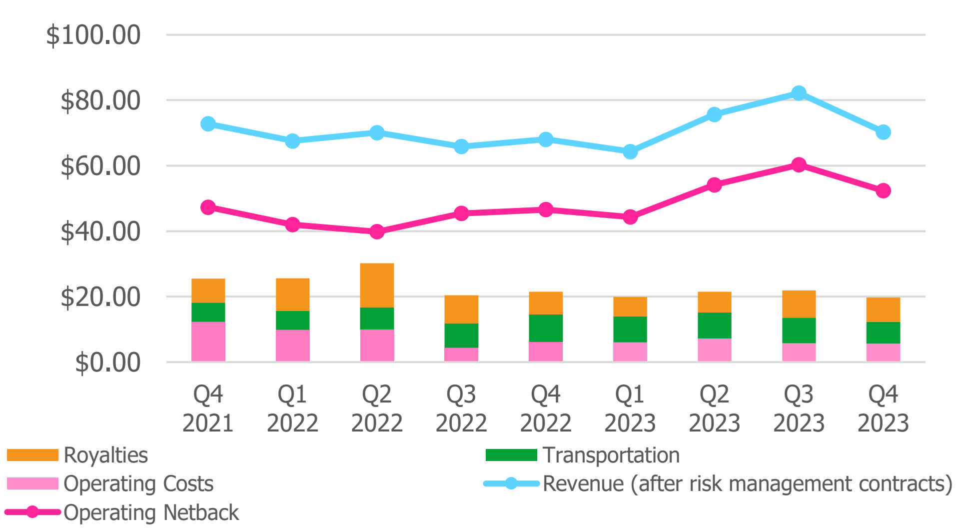


Q4 2023 Production By Area

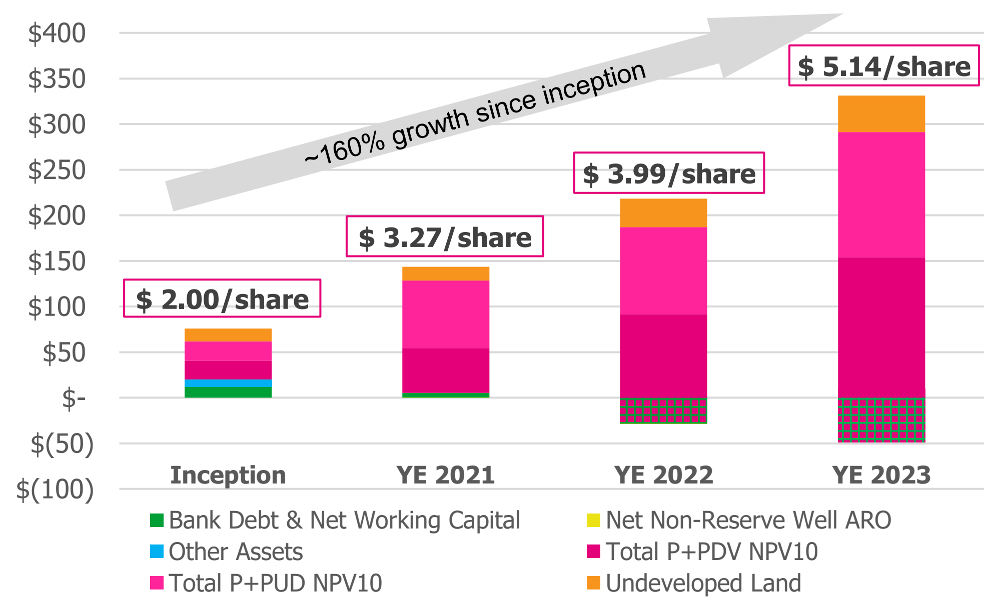


Q4 2023
4,209 bbl/d
100% Heavy Oil

Operating Netback ($/bbl)



Net Asset Value(2)(3) ($MM)



1. *Q1 2024 sales production guidance.*
2. *Total Proved Plus Probable (TPP) reserve value (NPV10) as per Year End 2023 McDaniel Reserve Reports and the Consultant Average Price Forecast; Undeveloped land value of $40.7 MM as per Year End 2023 Seaton-Jordan Report; Total Net Debt of $51.0 MM less $10 MM in MTM hedge gains relative to Consultant Average Price Forecast.*
3. *2023 Proved Reserve–Based NAV (discounted at 10%), excluding value for undeveloped land, is $165 MM ($2.64/share).*

2023 Reserves Highlights

Focused capital spending program at Figure Lake achieving strong reserve additions

2023 Corporate Reserves Additions

- TPP increased 56% year-over-year
- TPP per Debt Adjusted Share increased 23% year-over-year
- TPP additions replaced 5.8 times 2023 Annual Production
- TPP FD&A of $19.63/boe

- PDP increased 82% year-over-year
- PDP per Debt Adjusted Share increased 44% year-over-year
- PDP additions replaced 3.0 times 2023 Annual Production

Recycle Ratio[2]

- TPP Recycle Ratio of 2.9x (F&D of $18.03/boe)
- PDP Recycle Ratio of 2.2x (F&D of $24.22/boe)
- PPDP Recycle Ratio of 2.6x (F&D of $20.38/boe)

Reserve Life Index

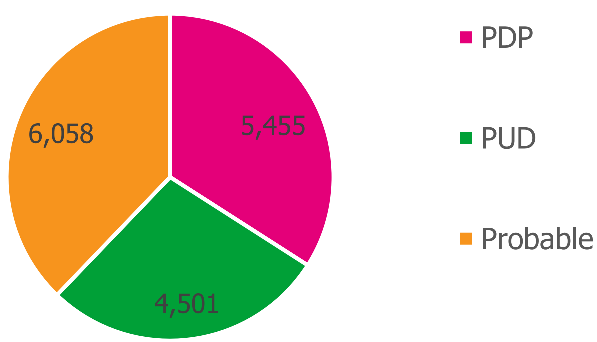
- RLI's ranging from 4.4 years (PDP) to 13.3 years (TPP)

YE 2023 Reserves (Mboe)[1]

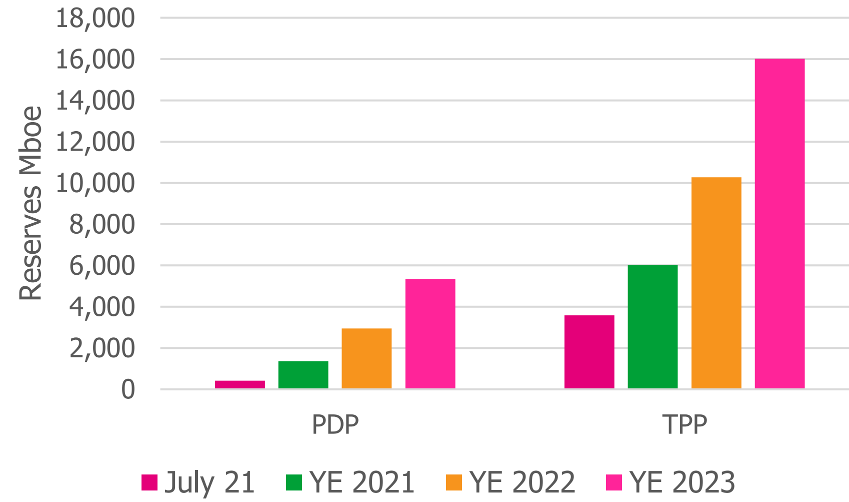
TP 10.0 MMboe

TPP 16.0 MMboe

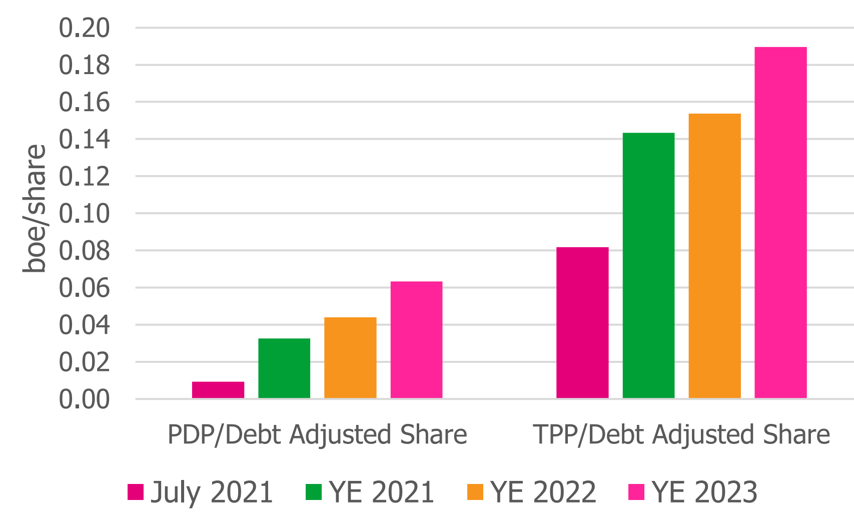
93% Heavy Oil



Reserves Growth[1]



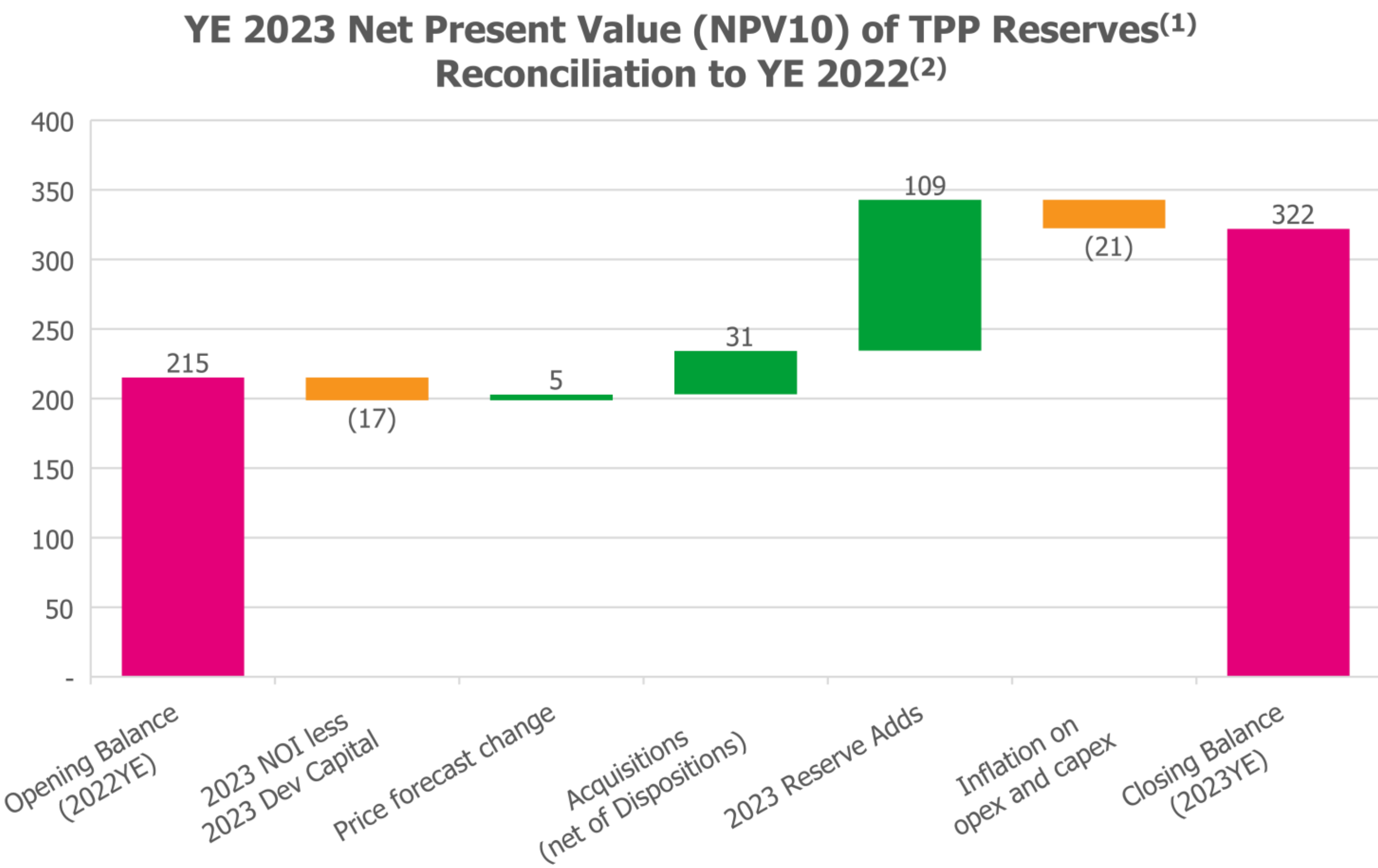
Reserves / Debt-Adjusted Share[1]

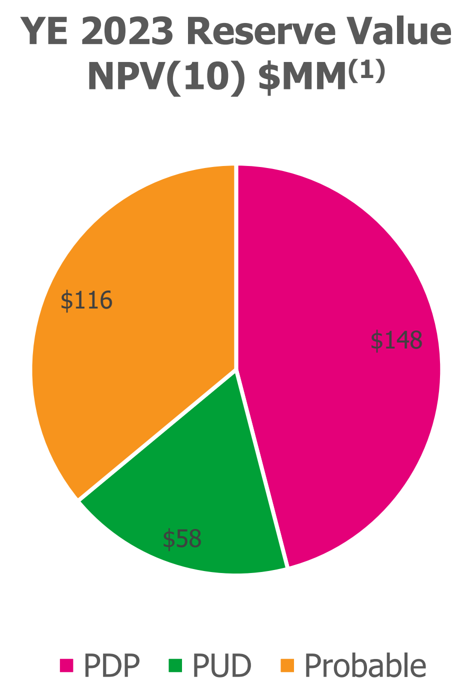


1. *Proved Developed Producing (PDP), Proved Undeveloped (PUD) and Proved Plus Probable (TPP) reserves as per Year End 2023 McDaniel Reserve Report.*
2. *Based on 2023 average netback of $53.14/bbl (excluding hedging gains/losses); F&D excluding acquisitions.*

2023 Net Present Value of Reserves

Reserve additions through the drill bit drove 50% increase in NPV10 value year-over-year





TP $206 MM ($3.30/share)

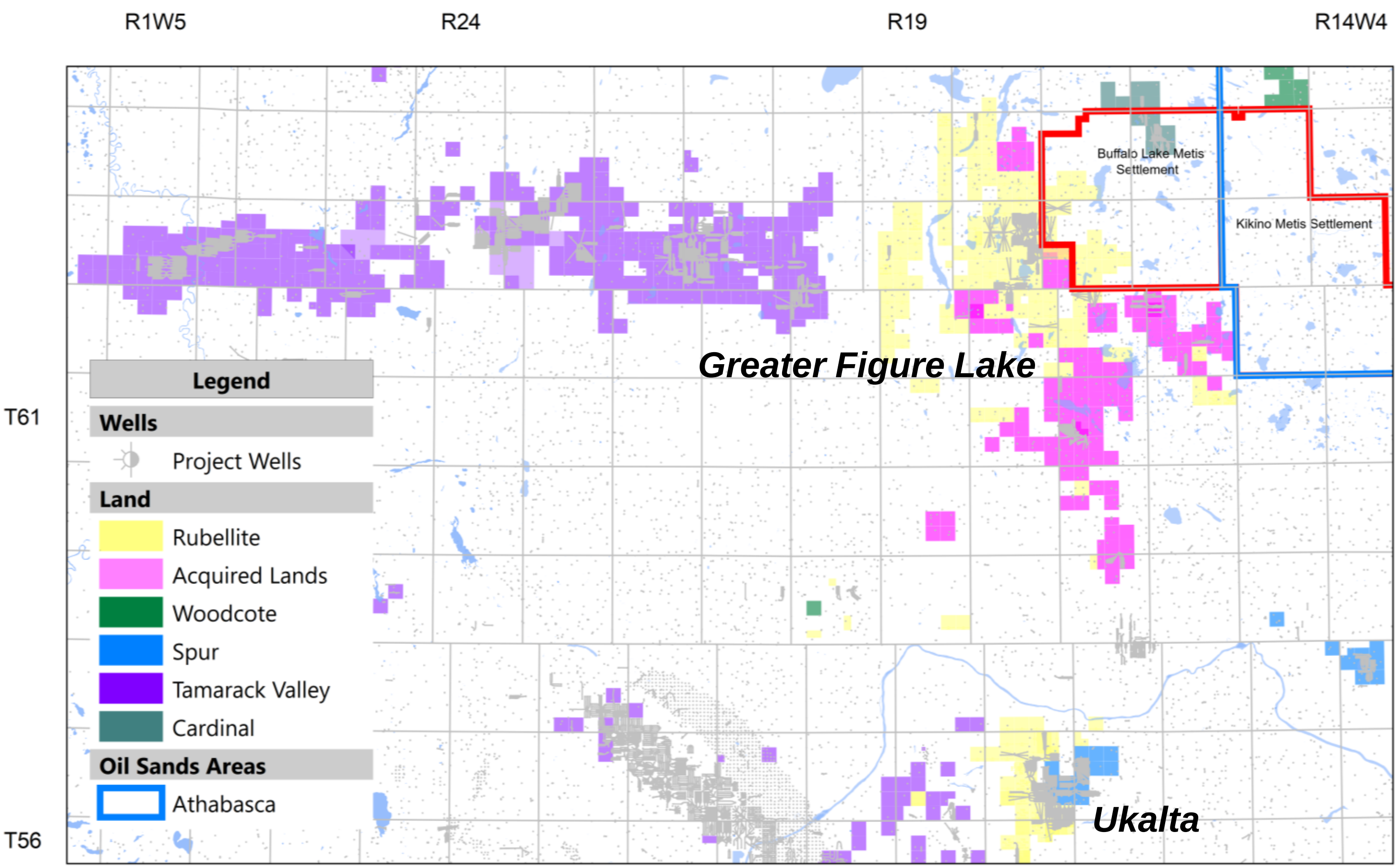
TPP $322 MM ($5.15/share)

1. *Proved Developed Producing (PDP), Proved Undeveloped (PUD) and Proved Plus Probable (TPP) reserves values as per Year End 2023 McDaniel Reserve Report based on the Jan 1, 2024 Consultant Average Price Forecast.*
2. *Proved Plus Probable (TPP) reserves values as per Year End 2022 McDaniel Reserve Report based on the Jan 1, 2023 Consultant Average Price Forecast.*

Southern Clearwater

Active Development and Extension Activity Ongoing

Southern Clearwater Play Fairway



Source: geoScout and competitor disclosures

Play History

***Figure Lake* – Development & Step-out Delineation Fueling RBY Growth**

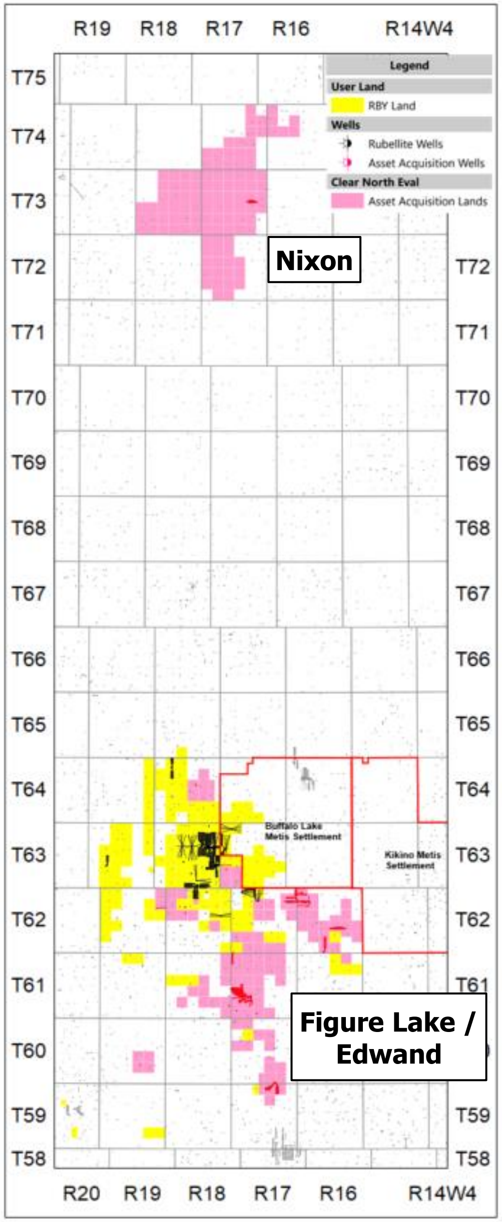
- 3,400 bbl/d Q4 2023 sales, including 436 bbl/d sales contribution from Acquired Lands for the quarter
- One 2.5-leg producing well drilled in early stage of play by a predecessor operator to set up exploration concept
- Sold 3-5% royalty on portion of lands to fund initial four well exploration program (South Pad & North Pad)
- Entered into agreement with Buffalo Lake Metis Settlement
- Accelerated development & step-out activity in 2022 and 2023
- Acquisition closed Nov 8, 2023 adding ~800 bbl/d of production and 107 net sections of land (90% undeveloped)
- Sold 1.5% Top-Up Royalty for $8 MM in Dec 2023
- 59 (59.0 net) multi-lat wells contributing to sales at the end of Q4 2023

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

- 534 bbl/d Q4 2023 sales
- Six 6-leg wells on production at RBY inception
- 26 (26.0 net) wells onstream Q4 2023
- Active industry competitors include Spur and Tamarack Valley

Acquisition

P&S executed October 19, 2023 – Closed November 8, 2023



Acquisition Summary

- **Purchase Price: $34.0 MM – Effective Oct 1, 2023**
- **Production: 800 bbl/d** (estimated at closing November 8, 2023)
  - 15 producing wells in Greater Figure Lake
  - Contributed 436 bbl/d to RBY Q4 2023 sales production
- **Greater Figure Lake Area Land: 107 net sections**
  - 27,392 net hectares, net of expected near-term expiries
  - Undeveloped Land = 96 net sections (24,482 net ha)
  - 49 high-graded inventory locations
    - 15 development locations at Figure Lake & South Edwand
    - 34 additional step-out locations in Greater Edwand area
    - Multiple additional exploratory prospects
- **Nixon Area Land: 108 net sections of exploration acreage**
  - Undeveloped Land = 108 net sections (27,648 net ha)

Key Strategic Rationale

- In line with robust Clearwater growth strategy
- Acquisition in core operating area highly synergistic to operating, administrative and capital execution activities
- Base production adds funds flow to enhance flexibility, support accelerated organic growth in strong oil price environment, and continue to pursue exploration & consolidation
- Adds strategic inventory outside Key Wildlife Biodiversity Areas at Figure Lake
- Materially increases undeveloped land position and exposure to exploration opportunities at Figure Lake, Edwand and Nixon

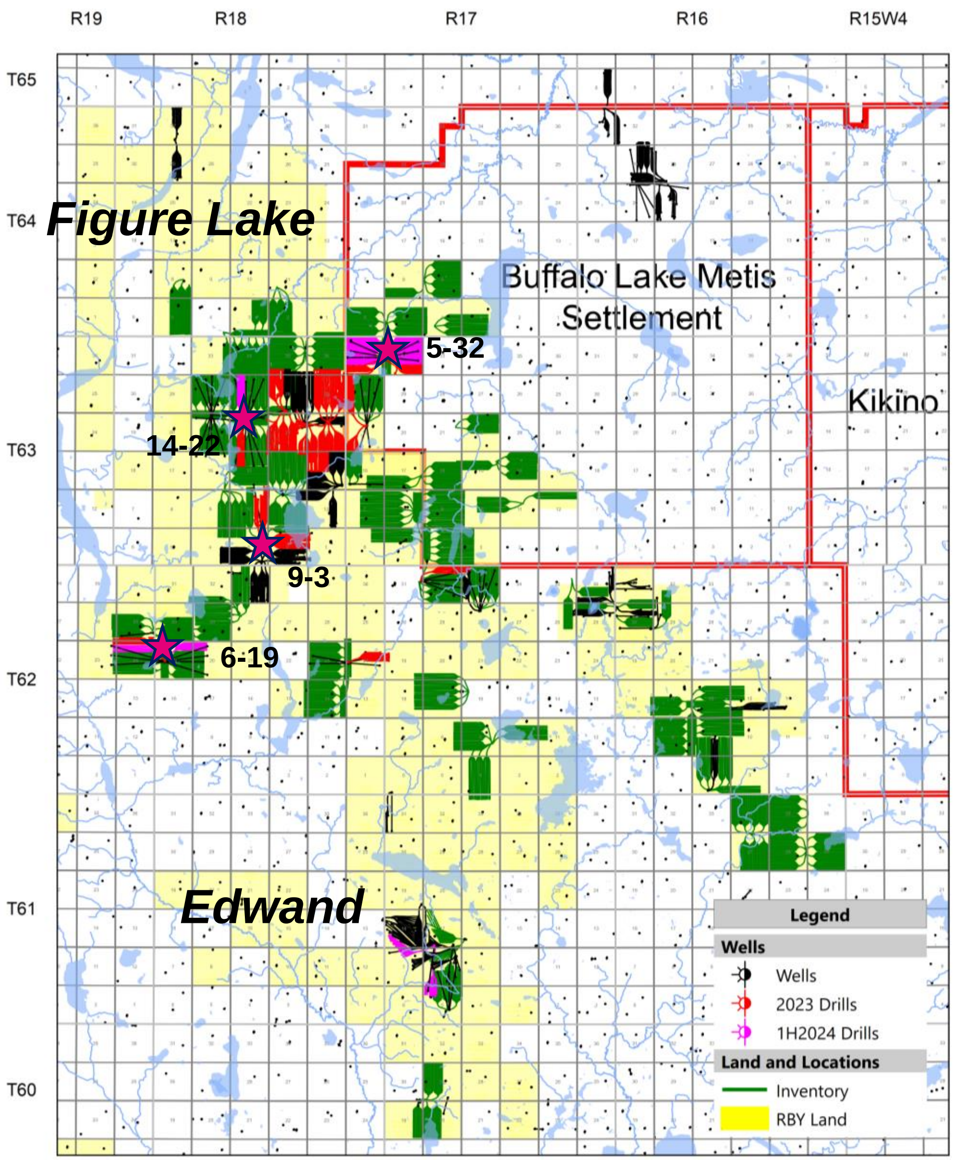
Acquisition Metrics[1]

- $28,500 per flowing boe/d

Rubellite Asset Profile | *Greater Figure Lake*

Pool Development and Extension

Asset Map



Source: GeoScout and competitor disclosures

Asset Summary

Working Interest: 100%

Q4 2023 Production: 3,400 bbl/d heavy oil

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

2023 Activity

- Drilled 27.0 net wells
- Managed land continuations & surface access restrictions
- Successful pool extensions on BLMS 5-32 Pad and at 6-19 Pad
- Advancing solution gas gathering and sales with on-stream date estimated in March 2025

Acquisition Assets Integrated into Operations

- Strategic operational fit with existing lands
- Optimization of road construction, pad drilling, production and sales oil trucking
- Since closing, have drilled and placed on production 3.0 net wells at IP30 rates exceeding type curve

Location Inventory as at YE 2023

- 62 (61.0 net) booked[1] Primary Zone HZ Development locations
- 165 additional inventory locations on existing lands

2024 Activity

- One rig program to drill 24 net development locations
- Second rig to drill up to 10 additional development / step-out delineation wells
- Gas conservation and sales plant pre-purchasing and pipeline reactivation project for Q1 2025 start-up with forecast rate of return of >75% on ~$7 MM capital investment
- Gas injection and EOR test

1. Total Proved Plus Probable (TPP) reserves as per Year End 2023 McDaniel Reserve Report.

Rubellite Asset Profile | *Figure Lake*

RUBELLITE ENERGY

2023 Development Results Outperforming Type Curve; Q4/23 Step-outs expanding development inventory

Type Curve and Production Results

2023 Development Drilling Results

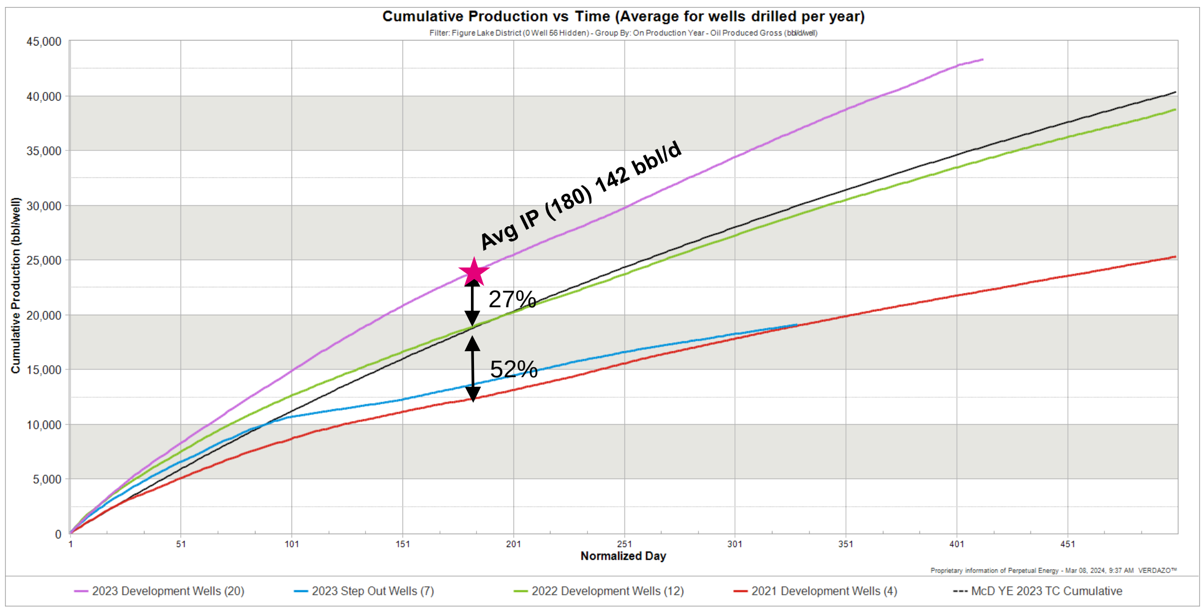
- 20 Development /Infill wells drilled and rig released
  - 9-23 Pad (2 wells Q1 RR)
  - 3-26 Pad (5 wells Q2/Q3 RR)
  - 15-24 Pad (8 wells total; 6 wells Q2/Q3 RR; 2 wells Q4 RR)
  - 9-3 Pad (4 wells Q4 RR)
  - 14-22 Pad (1 well Q4 RR)
- 19 Development / Infill wells on production for 30+ days
  - Average IP30: 178 bbl/d (19 wells)
  - Average IP60: 159 bbl/d (19 wells)
  - Average IP90: 164 bbl/d (16 wells)
  - Average IP180: 142 bbl/d (11 wells)
  - Average IP270: 120 bbl/d (6 wells)

Q4 2023 Step-Out Drilling Results

- 5-32 BLMS Pad
  - 02/04-31-63-17W4: IP30 325 bbl/d On prod Dec 1st
  - 00/01-32-63-17W4: IP30 168 bbl/d On prod Dec 17th
- 5-24 Pad
  - 00/09-24-62-18W4: IP30 15 bbl/d On prod Jan 5th
- 6-19 Pad
  - 00/16-23-62-19W4: IP30 256 bbl/d On prod Dec 29th
- Average IP30 189 bbl/d (4 wells)

Type Curve Assumptions

Assumptions (8-leg multi-lateral ~9,500m)	Tier 1		Tier 2
	McDaniel PUD YE 2023 [1]	McDaniel PPUD YE 2023 [1]	McDaniel PAUD YE 2023 [1]
Initial Rate (IP30)	117 bbl/d	119 bbl/d	96 bbl/d
IP60	112 bbl/d	116 bbl/d	93 bbl/d
Ultimate Recovery	90 Mbbl	130 Mbbl	100 Mbbl
Booked Locations	38 (38.0 net)		18 (17.0 net)
Economics[1]			
Capital (D,C & E)	$1.95 MM		
NPV10	$2.8 MM		
Payout	1.2 years		
Rate of Return	93 %		
Recycle Ratio	3.7 times		

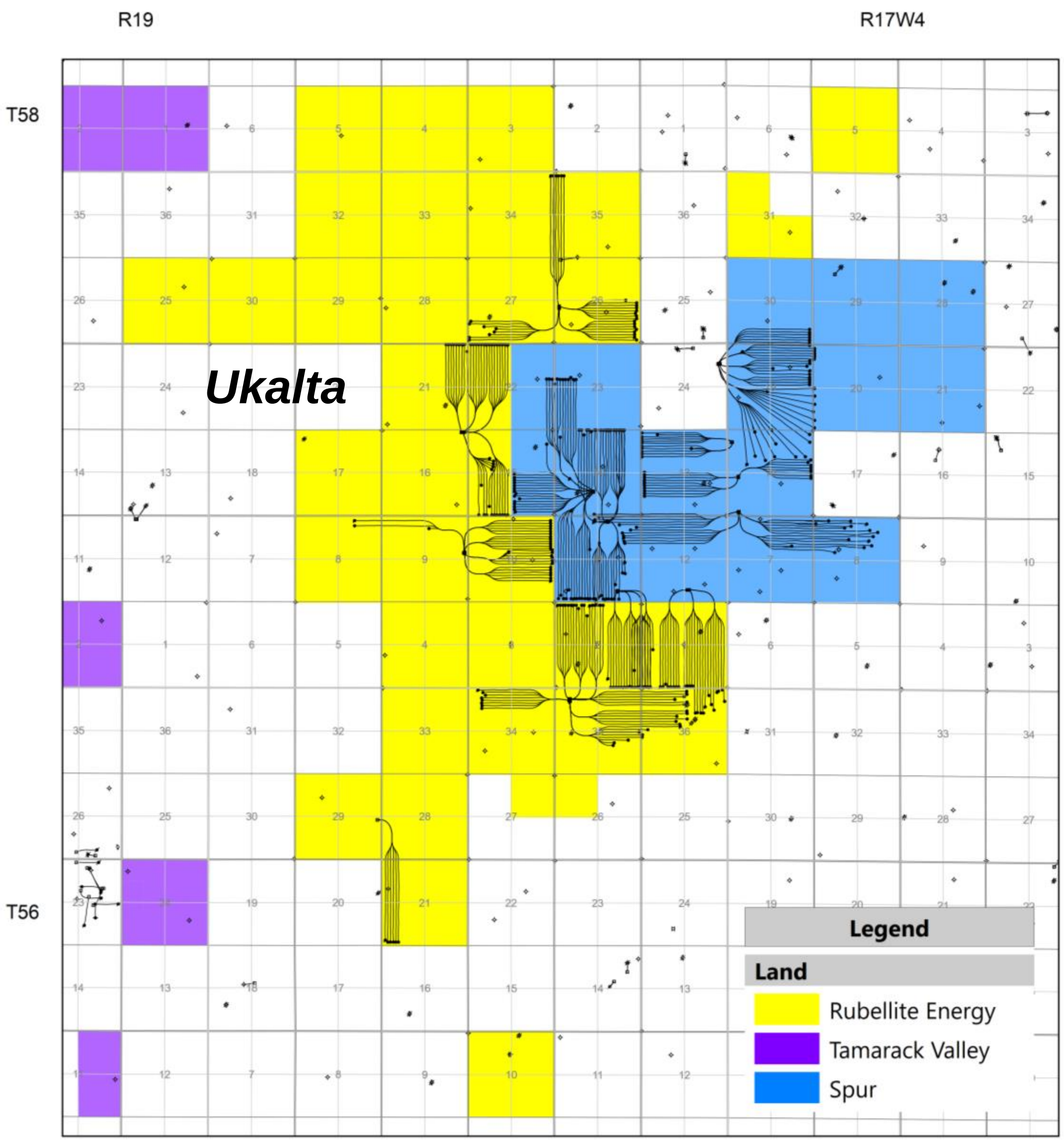


1. *Total Proved Plus Probable Undeveloped (P+PUD) reserve and economic parameters as per Year End 2023 McDaniel Reserve Report.*

Rubellite Asset Profile | *Ukalta*

Evaluating Enhanced Recovery and Secondary Zones

Asset Map



Source: geoScout and competitor disclosures

Asset Summary

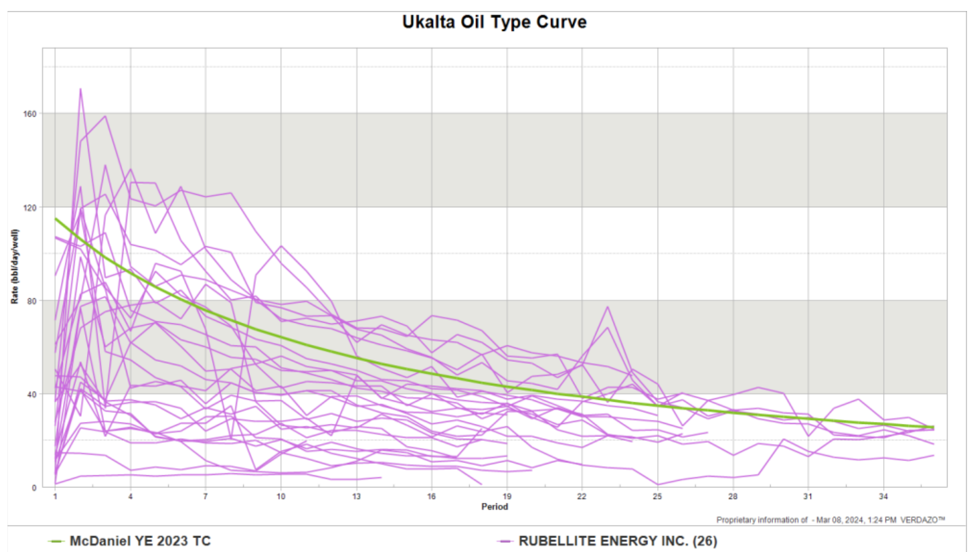
Working Interest: 100%

Q4 2023 Production: 534 bbl/d heavy oil

- 26 gross (26.0 net) Primary Zone multi-laterals on sales production
- Harvest free cash flow to fund growth at Figure lake

Prospect Inventory

- 10 booked[1] Primary Zone HZ Development locations
- Secondary zone potential in Upper Clearwater and Clearwater channel facies

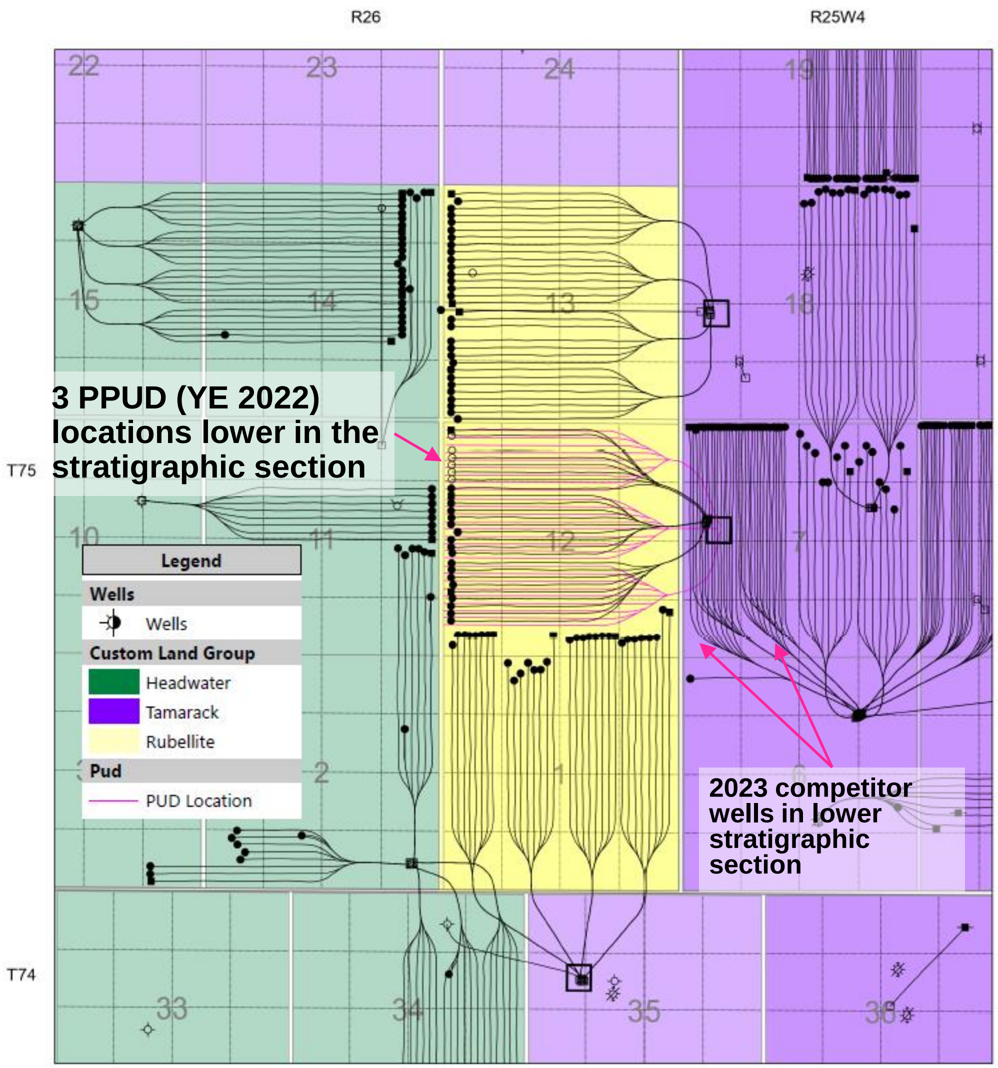


1. *Total Proved Plus Probable Undeveloped (P+PUD) reserve locations and type curve parameters as per Year End 2023 McDaniel Reserve Report.*

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 (0.9 net) sections
- Converted to after payout working interest May 1, 2023

Q4 2023 Production: 272 bbl/d heavy oil

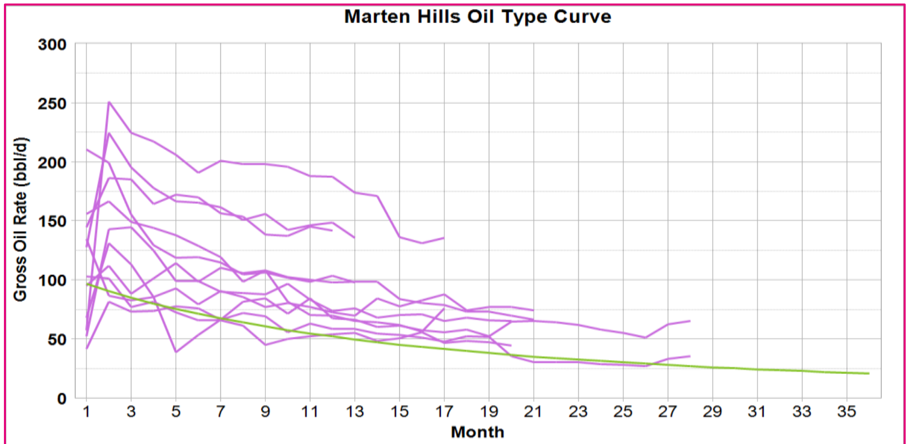
- 11 gross (3.3 net) wells on production
- Generating free cash flow to fund growth at Figure lake and exploration

Prospect Inventory

- 3 (0.9 net) booked[1] Lower Clearwater Development locations

2024 Strategy

- Implement enhanced oil recovery scheme to reduce decline, improve reserve recovery and maximize value



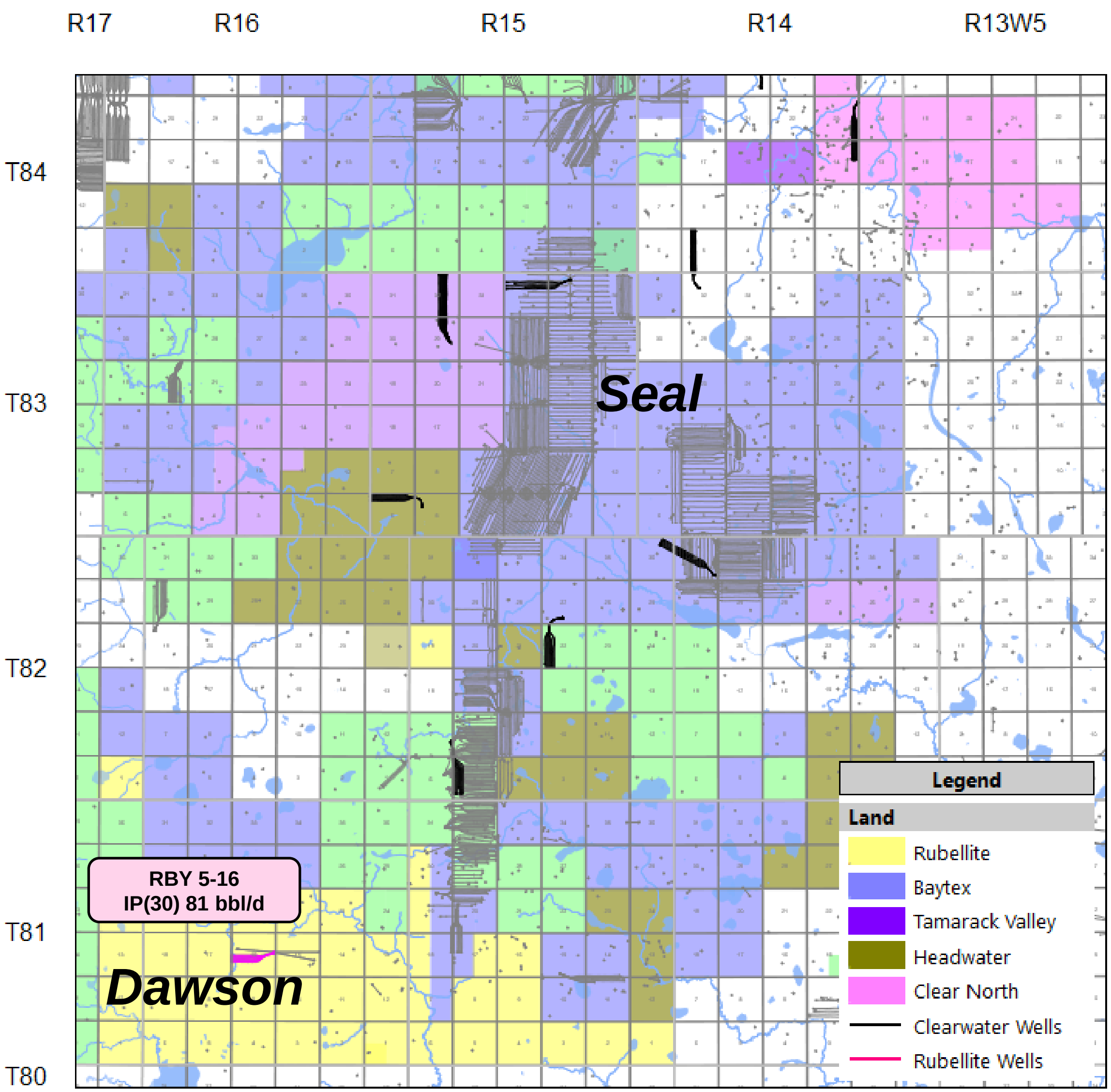
1. *Total Proved Plus Probable Undeveloped (P+PUD) reserve parameters as per Year End 2022 McDaniel Reserve Report*

1. *Production at Marten Hills is reported at the After Payout Working Interest. Project Payout occurred in January 2023 and was effective May 1, 2023.*

Dawson - Northern Clearwater Exploration

Encouraging early results at Dawson

Asset Map

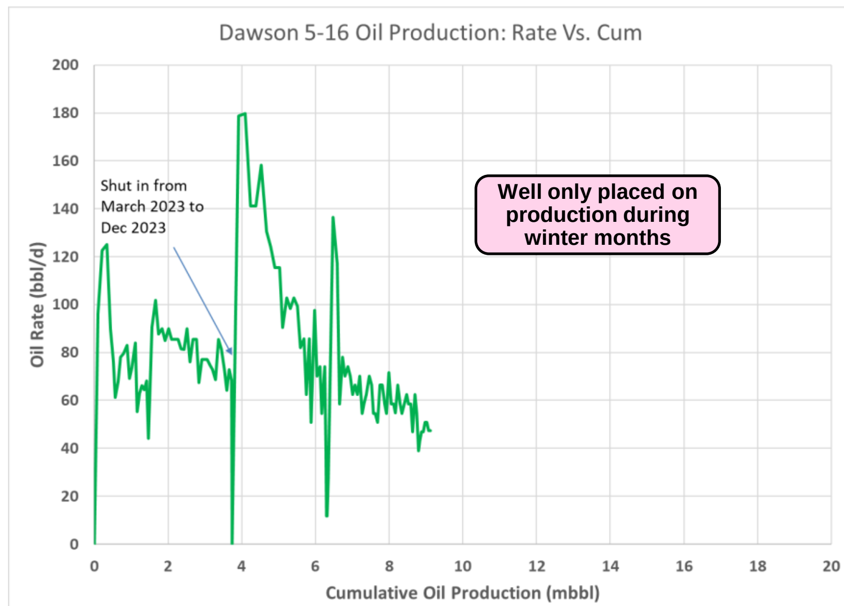


Source: GeoScout and competitor disclosures

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
- Re-started production in late December 2023
  - Monitoring performance to assess all-weather road construction
- Elected to drill second well (50% WI) to earn additional acreage in 2024
  - Targeting increased length to >10,000m to improve productivity, capital efficiency and reserve recovery



Rubellite Guidance

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

Guidance *(March 14, 2024)*

	Q1 2024	2024
E&D Capital Expenditures [1][2][3] ($ MM)	$12 - $13	$70 - $75
Average Sales Production[4] (bbl/d)	4,450 – 4,500	4,600 – 4,900
Heavy Oil Wellhead Differential [5] ($/bbl)	$6.50 - $7.00	$6.50 - $7.00
Royalties [6] (% of revenue)	11.0% - 12.0%	11.0% - 12.0%
Operating Costs ($/bbl)	$6.50 - $7.00	$6.00 - $6.50
Transportation Costs ($/bbl)	$7.50 - $8.00	$7.50 - $8.00
G&A ($/bbl)	$5.50 - $6.00	$5.50 - $6.00

1. *Exploration and Development capital expenditures includes the drilling of six (6.0 net) horizontal multi-lateral wells and one (1.0 net) vertical stratigraphic core evaluation well in Q1 2024 and up to 34 (34.0 net) horizontal multi-lateral development / step-out wells in the greater Figure Lake area in aggregate for 2024. Includes the drilling of 1 (0.3 net) waterflood Lower Clearwater infill well at Marten Hills and 1 (0.5 net) earning well at Dawson in Q4 2024*
2. *Includes $7.0 million of capital spending required for the gas gathering infrastructure project at Figure Lake , of which $1.4 million is forecast to be spent in Q1 2024*
3. *Excludes land purchases and acquisitions, if any*
4. *2024 Exit Rate guidance of 5,000 to 5,200 bbl/d*
5. *Quality differential relative to Western Canadian Select (C$/bbl) benchmark pricing*
6. *Includes Crown, freehold and GORRs*

Development Parameters

- Single pad batteries with minimal infrastructure
- Oil sales from new wells forecast approximately 5 weeks post spud after base-oil load fluid recovery
  - Load oil from oil-based drilling mud recovered for re-use
- 2024 development / step-out drilling program
  - Continuous one-rig program at Figure Lake to drill 24 (24.0 net) wells
  - Second rig start-up at Figure Lake as early as late Q2 2024 to drill up to 10 (10.0 net) development / step out wells
  - 1 (0.3 net) Marten Hills waterflood Lower Clearwater infill well in Q4 2024
  - No drilling planned at Ukalta
- Gas plant and pipeline construction at Figure Lake for gas conservation through sales tie-in with start-up in early 2025

Exploration Activities

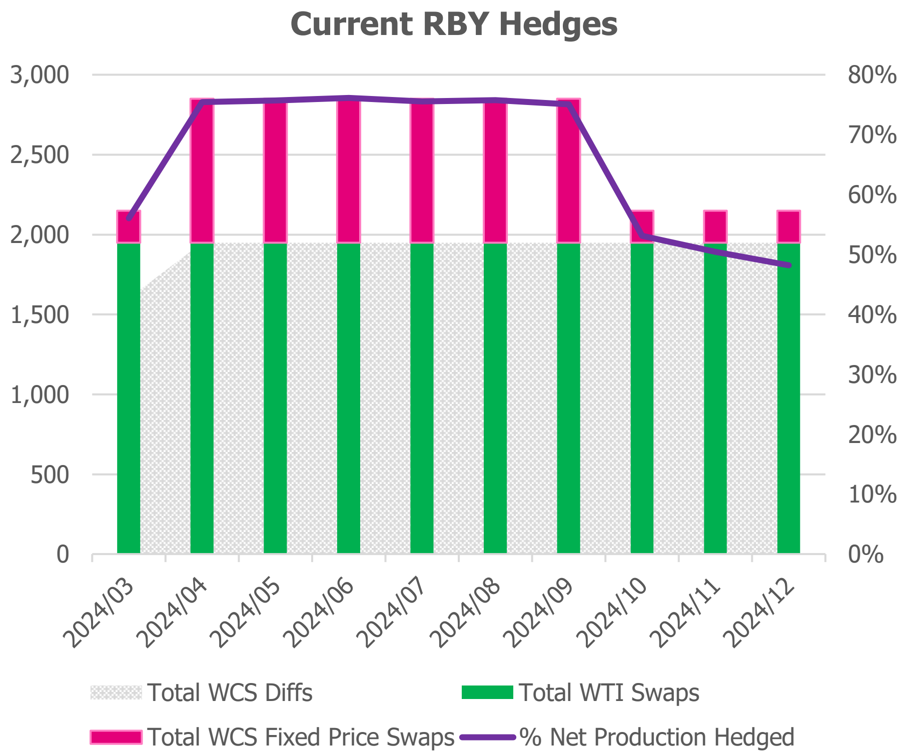
- Identifying new fairways and zones of interest
- Pursuing risk-managed capture strategies
- Advancing evaluation of Clearwater exploratory acreage
  - Dawson prospect – Northern Exploration
    - *1 successful multi-lateral well drilled in Q1 2023*
    - *Election made to drill a second 50% earning well in Q4 2024*
  - Craigend prospect
    - *Vertical stratigraphic core evaluation well drilled in Q1 2024 – waiting on core analysis*
  - Nixon prospect
    - *Acquiring surface access for multi-lateral evaluation well*

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

Commodity Price Risk Management

Price protection on an average of 2,617 bbl/d at an average WCS price of ~$84.48 Cdn/bbl over the balance of 2024

2024 Oil Price Management



Commodity Price Hedge Positions *(as at March 14, 2024)*

	Q2 24	Q3 24	Q4 24	Cal 25
WTI CAD/bbl Swap Volume (bbl/d) ($CAD/bbl)	1,750 $104.48	1,750 $104.48	1,750 $104.48	
WTI USD/bbl Swap Volume (bbl/d) ($USD/bbl)	200 $78.75	200 $78.75	200 $78.75	
WCS CAD/bbl Swap Volume (bbl/d) ($CAD/bbl)	200 $84.33	200 $84.33	200 $84.33	
WCS USD/bbl Swap Volume (bbl/d) ($USD/bbl)	700 $64.37	700 $63.79		
WCS Differential CAD/bbl Swap Volume (bbl/d) ($CAD/bbl)	1,600 ($21.50)	1,600 ($21.50)	1,600 ($21.50)	
WCS Differential USD/bbl Swap Volume (bbl/d) ($USD/bbl)	350 ($13.95)	350 ($13.95)	350 ($13.95)	
CAD/USD FX Swap Notional period amount ($USD) ($USD/month) ($CAD/$USD) ($CAD/month)	$5,325,000 $1,775,000 $1.3659 $2,424,473	$5,325,000 $1,775,000 $1.3659 $2,424,473	$5,325,000 $1,775,000 $1.3659 $2,424,473	$12,000,000 $1,000,000 $1.3660 $1,366,000

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

- 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

ESG Excellence

Strong ESG performance driven by living our values

Water

- No fracture stimulation required in Clearwater play with multi-lateral drilling technology therefore minimal fresh water usage

Land

- Surface footprint minimized with multi-well pad development
- Onsite drill cutting cleaning and oil-based mud recovery and re-use to reduce trucking and landfill waste
- Minimal non-producing Asset Retirement Obligations

Air

- Consolidated land positions present future pipeline tie-in opportunities to reduce trucking
- Low emissions pad site battery design instituted
- Advancing solution gas tie-ins to sales to eliminate incineration

Innovation

- Connected to multiple industry clean tech alliances

Safety First

- Comprehensive EH&S program driving strong performance
- Through Perpetual, ranked #1 out of 256 oil and gas companies on Workers Compensation Board scorecard

Employees & Service Providers

- Field, contractors and office team have long established tenure of working together through Perpetual’s 20 year operating history
- Extensive and purposeful indigenous contractor engagement strategy

Community

- Hands-on stakeholder engagement for surface land access
- Listening-centric indigenous relations approach grounded in mutual respect with desire to help build community capacity
- Over $2.0 MM donated to the United Way of Calgary since Perpetual team’s inception in 2003
- Annual employee and corporate community investment campaigns and days of caring
- Extensive leadership and volunteer involvement in industry, community and charitable organizations

Independent Board Oversight

- Environment, Health and Safety programs and performance oversight since inception
- Performance-based compensation practices
- Triple Zero EH&S Goal of Zero spills/Zero injuries/Zero vehicle incidents embedded in operational excellence bonus component

Strong Corporate Culture

- Flex Life mantra aligning family and wellness priorities
- Visible equity and diversity leadership with 60% female representation on Board of Directors
- Entrepreneurial Spirit & Accountability drives engaged and inclusive team

Creating Differentiated Value for Shareholders

Fully funded growth opportunity in the prolific Clearwater play

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
  - 2023 66% Perpetual / 34% Rubellite
  - 2024 expected to be ~ 50% Perpetual / 50% Rubellite
- Rubellite has its own unique software, professional fees and other public company / corporate costs
- G&A expected to decline on a per boe basis as production continues to grow
- Enhanced 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

Additional Information

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

3200, 605 – 5 Avenue SW
Calgary, Alberta Canada T2P 3H5

Slide Notes

Slide 1

1. Current shares outstanding as at March 14, 2024, 3.7 million share awards outstanding and 4.0 million share purchase warrants (expire October 5, 2026; $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 March 13, 2024 and a share price of $2.38
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. "EOR" means enhanced oil recovery
5. Adjusted funds flow is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
6. Free funds flow is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
7. 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
5. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
6. "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, 2023 and a preparation date of March 14, 2024
7. "TPP" means total proved plus probable reserves in the McDaniel Reserve Report

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. Adjusted funds flow is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
4. "McDaniel" means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators
5. "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, 2023 and a preparation date of March 14, 2024
6. 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, 2024 Pricing" as disclosed in the Company's Annual Information Form which is available under the Company's profile on SEDAR+ at www.sedarplus.ca
7. "PUD" means locations that have been booked in the proved undeveloped category in the McDaniel Reserve Report
8. "PPUD" means locations that have been booked in the proved plus probable undeveloped category in the McDaniel Reserve Report
9. Net debt is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
10. "TPP" means total proved plus probable reserves in the McDaniel Reserve Report
11. "NPV10" refers to the before tax net present value of future net revenue of the applicable reserves category in the McDaniel Reserve Report, discounted at 10%

Slide Notes (continued)

Slide 6

1. Capital is a 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, 2023 and a preparation date of March 14, 2024
5. "June 2021 Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of June 1, 2021, adjusted for June 15, 2021 strip pricing
6. "YE 2021 Reserves" means the independent engineering evaluation of the crude oil, natural gas and NGL reserves, prepared by McDaniel with an effective date of December 31, 2021 and a preparation date of March 9, 2022 based on the "Consultants Average Jan 1, 2022 Pricing"
7. "YE 2022 Reserves" 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 based on the "Consultants Average Jan 1, 2023 Pricing"
8. "TPP" means total proved plus probable reserves in the McDaniel Reserve Report
9. "PDP" means locations that have been booked in the proved developed producing category in the McDaniel Reserve Report
10. "PPDP" means locations that have been booked in the proved plus probable producing category in the McDaniel Reserve Report
11. "PUD" means locations that have been booked in the proved undeveloped category in the McDaniel Reserve Report
12. "F&D" and "FD&A" costs are a non-GAAP financial. See "Non-GAAP and Other Financial Measures" in the Advisories
13. Recycle ratio is a non-GAAP financial ratio. See “Non-GAAP and Other Financial Measures” in the Advisories
14. "RLI" means Reserve Life Index and is calculated by dividing the reserves in the McDaniel Reserve Report by total annualized production
15. "TPP per debt adjusted share" is determined by dividing year-end total proved plus probable reserves by debt adjusted shares. Debt adjusted shares is determined by dividing total debt outstanding at period end by the closing share price and adding the resulting quotient to total shares outstanding at period end
16. "PDP per debt adjusted share" is determined by dividing year-end proved developed producing reserves by debt adjusted shares. Debt adjusted shares is determined by dividing total debt outstanding at period end by the year-end closing share price and adding the resulting quotient to total shares outstanding at period end
17. "TPP FD&A" is determined by dividing total proved plus probable reserves by total finding and development costs (including acquisitions and dispositions).
18. "TPP", "PDP" and "PPDP" recycle ratio ratios are determined by dividing the operating netback per boe by the applicable reserve category F&D costs.

Slide Notes (continued)

Slide 7

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, 2023 and a preparation date of March 14, 2024
3. "YE 2022 Reserves" 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 based on the "Consultants Average Jan 1, 2023 Pricing"
4. "NPV10" refers to the before tax net present value of future net revenue of the applicable reserves category in the McDaniel Reserve Report, discounted at 10%
5. "TP" means total proved reserves in the McDaniel Reserve Report
6. "TPP" means total proved plus probable reserves in the McDaniel Reserve Report
7. "PDP" means locations that have been booked in the proved developed producing category in the McDaniel Reserve Report
8. "PUD" means locations that have been booked in the proved undeveloped category in the McDaniel Reserve Report
9. "NOI" means net operating income, as determined in accordance with IFRS
10. "TP per share" is calculated as the NPV10 of total proved reserves divided by total shares outstanding at December 31, 2023
11. "TPP per share" is calculated as the NPV10 of total proved plus probable reserves divided by total shares outstanding at December 31, 2023
12. 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 9

1. See “Drilling Locations” in the Advisories
2. Capital is a non-GAAP measure. See “Non-GAAP and Other Financial Measures” in the Advisories
3. Free funds flow is a non-GAAP measure. See “Non-GAAP and Other Financial Measures” in the Advisories

Slide 10

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 Notes (continued)

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, 2023 and a preparation date of March 14, 2024
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, 2024 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, 2023
8. Capital is a non-GAAP measure. See “Non-GAAP and Other Financial Measures” in the Advisories
9. Payout, rate of return and recycle ratio are non-GAAP ratios. See “Non-GAAP and Other Financial Measures” in the Advisories

Slide 12

1. See “Drilling Locations” in the Advisories

Slide 13

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, 2023 and a preparation date of March 14, 2024
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, 2024 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
8. "TPP" means total proved plus probable reserves in the McDaniel Reserve Report

Slide 14

1. See “Drilling Locations” in the Advisories

Slide Notes (continued)

Slide 15

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 % of revenue" 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. "Exit rate guidance" means expected sales volumes for at the end of 2024
9. Adjusted funds flow is a non-GAAP measure. 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 16

1. Prices reported are the weighted average prices for the period
2. Western Canadian Select ("WCS")
3. Adjusted funds flow is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
4. Capital is a non-GAAP measure. See "Non-GAAP and Other Financial Measures" in the Advisories
5. Forecasted production based on current street guidance
6. Hedge positions current to March 14, 2024. Full hedge positions by product are as follows:

Commodity price risk management

As at March 14, 2024, 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 ($/bbl)
Crude Oil	200 bbl/d	Mar 2024 - Dec 2024	WTI (USD$/bbl)	Swap - sold	$78.75
Crude Oil	350 bbl/d	Apr 2024 - Dec 2024	WCS Differential (USD$/bbl)	Swap - sold	($13.95)
Crude Oil	700 bbl/d	Apr 2024 - Jun 2024	WCS (USD$/bbl)	Swap - sold	$64.37
Crude Oil	700 bbl/d	Jul 2024 - Sep 2024	WCS (USD$/bbl)	Swap - sold	$63.79
Crude Oil	1,750 bbl/d	Mar 2024 - Dec 2024	WTI (CAD$/bbl)	Swap - sold	$104.48
Crude Oil	1,600 bbl/d	Mar 2024 - Dec 2024	WCS Differential (CAD$/bbl)	Swap - sold	($21.50)
Crude Oil	200 bbl/d	Mar 2024 - Dec 2024	WCS (CAD$/bbl)	Swap - sold	$84.33

Foreign exchange risk management

As at March 14, 2024, the Company entered into the following foreign exchange risk management contracts:

Contract	Notional amount	Term	Price (CAD$/US$)
Average rate forward (CAD$/US$)	$1,775,000 US$/month	Mar 1 - Dec 31, 2024	1.3659
Average rate forward (CAD$/US$)	$1,000,000 US$/month	Jan 1 - Dec 31, 2025	1.3660

Slide 18

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

Slide 19

1. G&A per BOE 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" below and in the Management's Discussion and Analysis for the period ended December 31, 2023 ("December 31, 2023 MD&A") and "Risk Factors" in the Annual Information Form for the year ended December 31, 2023.

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 December 31, 2023 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 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 borrowings 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, 2023, 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" and "FD&A" costs are used as a measure of capital efficiency. The F&D cost calculation includes all capital expenditures, excluding acquisition and disposition capital, 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. FD&A includes the impact of acquisition and disposition capital.

"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 (continued)

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", "Expierenced Management and Independent Board of Directors", "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: the number of wells to be drilled and rig released during 2024; the plan to continue exploration activities to pursue additional prospective land capture and de-risk acreage; anticipated exploration and development capital spending levels in the first quarter of 2024 and the full year 2024; the expectation that the forecast activities will be funded from adjusted funds flow, with excess free funds flow potentially directed to organic growth, additional exploration activities, acquisitions and returns to shareholders; expectations respecting Rubellite's future exploration, development and drilling activities and Rubellite's business plan; and including the other 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 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 Energy Inc. 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; 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; failure to obtain required regulatory and other approvals including drilling permits and the impact of not receiving such approvals on the Company's long-term planning; climate change risks; severe weather (including wildfires and drought); risks of wars or other hostilities or geopolitical events, 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 legislation, including but not limited to tax laws, royalties and environment regulations (including greenhouse gas emission reduction requirements and other decarbonization or social policies) and general economic and business conditions and markets.

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, 2023 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.

Advisories (continued)

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.

Oil and Gas Reserve Definitions

Reserves are estimated remaining quantities of crude oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of capital assumptions, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates. Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the estimated proved plus probable reserves.

Initial Production Rates

Any references in this presentation to initial production rates, including IP30, IP60, IP90, IP180 and IP270 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.

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 Rubellite McDaniel Reserve Report (Dec. 31, 2023) and account for drilling locations that have associated proved and/or probable reserves, as applicable, and have not yet been drilled at the time of preparation of the report. 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 240 (236.9 net) drilling locations identified herein 49 (49.0 net) are proved locations at year-end 2023, 26 (22.9 net) are undrilled probable locations at year-end 2023 and 165 (165.0 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.

Advisories (continued)

Reserve Estimates

The reserves estimates contained in this presentation are as at December 31, 2023 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, 2023 which is available under the Company’s profile on SEDAR+ at www.sedarplus.ca.

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