Tuktu
RESOURCES LTD.

Positioned for Success in Light Oil through drilling in the Deep Basin

TSXV: TUK

October 2024

Positioned for Accelerated Growth in the Southern Alberta Deep Basin

Tuktu RESOURCES LTD.

- ✓ **Expansive Land Holdings:** A material presence with 167 gross (161 net) sections, offering significant development potential.
- ✓ **Stable Production Base:** A combined production rate of ~ 530 barrels of oil per day (net), and ~ 320 BOE/d sweet gas, with a very low 10-15% decline rate.
- ✓ **Solid Net Operating Income Foundation:** Anticipating a 2025 Net Operating Income of $6 MM(1), providing a solid base to fund future opportunities.
- ✓ **Future-Forward Potential:** With over 100 un-booked(2), high-potential locations across four repeatable plays (three light oil, one sweet gas), the Company is poised for growth. The Company's near-term drilling will focus on its recently announced oil discovery in the Deep Basin.
- ✓ **Proven Production capability in our Vertical Discovery Well:** Recent well production of 15.3 Mbbl in 39 days suggests a high permeability reservoir which may extend over more than 26.5 sections of land currently held by Tuktu.

(1) Based on an estimated monthly NOI, Dec 2024, then annualized (assuming a $23/BOE netback and 800-850 BOE/d).
(2) See "*Advisories – Oil and Gas Advisories – Drilling Locations*".

Driving Competitive Advantage with Innovation and Expertise

- ✓ **Innovation**: Accomplished Team and Board that has a record of finding and developing plays which have fallen out of favor with many other producers (…we are not just another Montney producer).

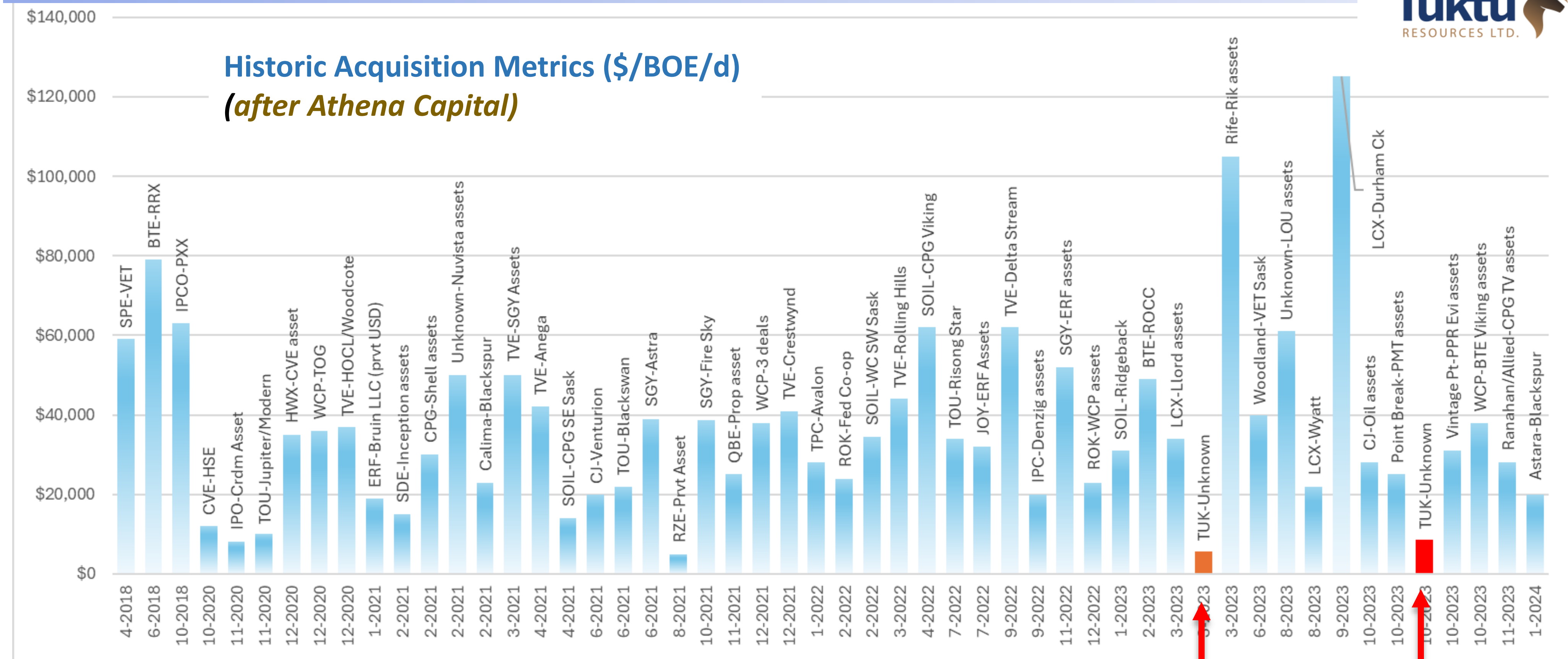
- ✓ **New pools/new areas:** We operate in regions that have been less active, leveraging lower competition and reduced costs, resulting in favorable acquisition metrics.

- ✓ **A Focus on Conventional Reservoirs:** These have greater natural permeability and effective porosity that generally exceed those of unconventional reservoirs. Such reservoirs may need less (if any) fracture stimulation, thus are less costly to exploit.

- ✓ **Advanced Technical Expertise:** Leveraging complex foothills drilling technologies to tap into structured deep-basin plays, allowing Tuktu to operate in plays that are a natural fit for the team’s unique skill set.

- ✓ **Proven Success since Recapitalization:** All the above has been accomplished since Tuktu’s recapitalization transaction in July 2022.

Best-in-Class Acquisition Transactions



Acquisition 2

Acquisition 3

Long-Term Reserve Development Upside on existing Asset Base

Acquisition 3: <u>Current</u> Asset Acquisition Reserves and Net Present Value of Future Net Revenue[1,2,5]

- PDP 0.31 MMbbl, $5.5 million NPV10%
- TPP 2.1 MMbbl, $19.6 million NPV10%

Acquisition 2: Southern Alberta Acquisition Announced March 21, 2023[3,5]

- PDP 727 MBoe ,$3.7 million NPV10%
- TPP 1,449 Mboe, $6.2 million NPV10%

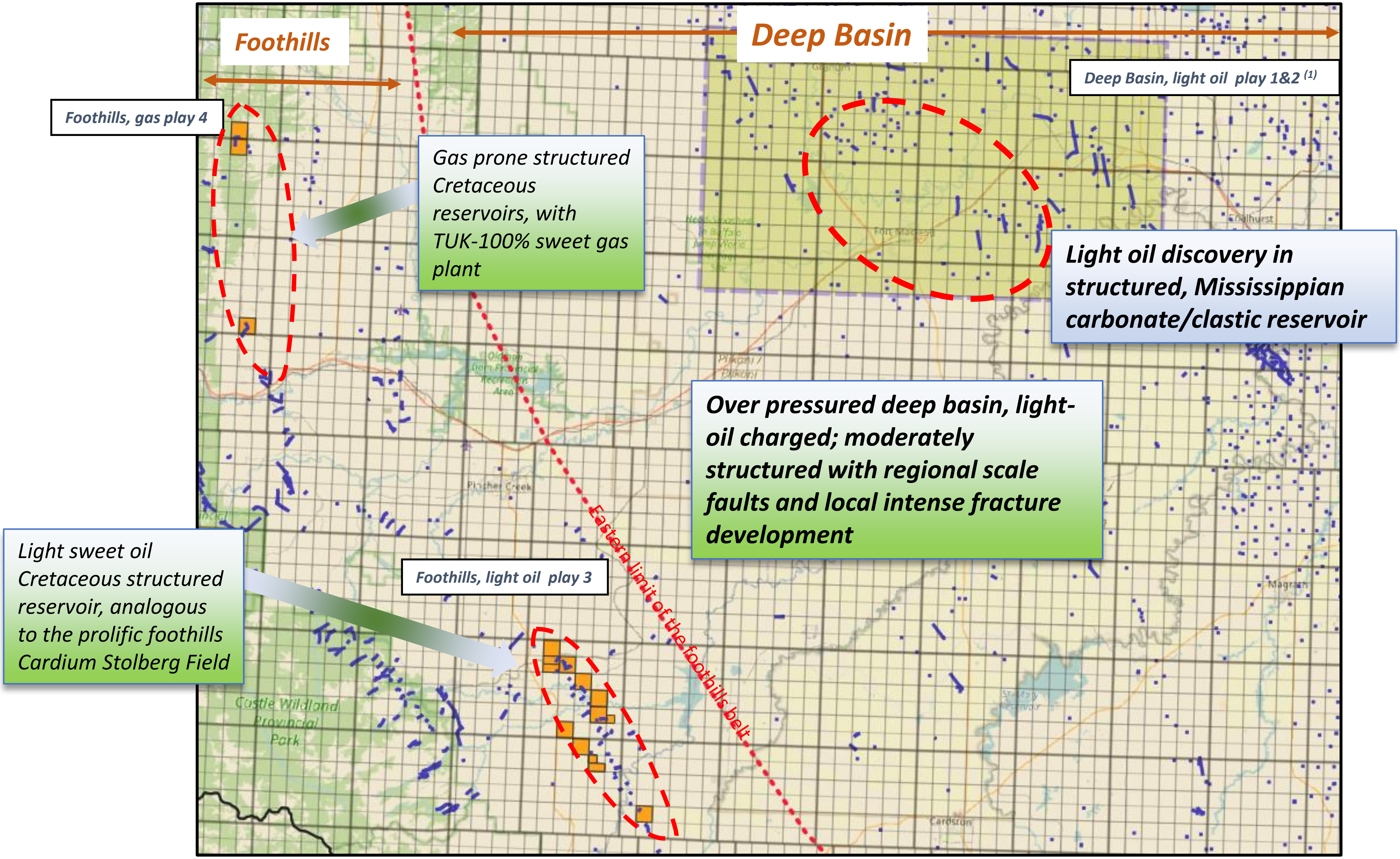
Acquisition 1: Southern Alberta Oil Acquisition, Announced December 8, 2022[4,5]

- PDP 27 MBoe ,$0.6 million NPV10%
- TPP 1,329 Mboe, $35.1 million NPV10%

(1) Represents the Adjusted Purchase Price divided by the estimated 2023 field netback for the Asset (defined herein), based on a projection of costs and declines of the Vendor's Lease Operating Statements and on September 20, 2023 Strip Pricing. The Adjusted Purchase Price is the purchase price of $3.0 million less estimated interim adjustments of $1.5 million, based on nine months of adjustments.
(2) Reserves information is based on the Acquisition 3 Reserves Report (as defined herein), see *"Advisories – Oil and Gas Advisories – Reserves Information"*.
(3) Reserves information is based on the Acquisition 2 Reserves Report (as defined herein), see *"Advisories – Oil and Gas Advisories – Reserves Information"*.
(4) Reserves information is based on the Acquisition 1 Reserves Report (as defined herein), see *"Advisories – Oil and Gas Advisories – Reserves Information"*.
(5) NPV10% means the net present value of future net revenue before income tax discounted at 10%. This metric does not represent the fair market value of the applicable assets. See "*Advisories – Oil and Gas Advisories – Reserves Information*".

Well positioned across 4 repeatable plays with 100+ Locations

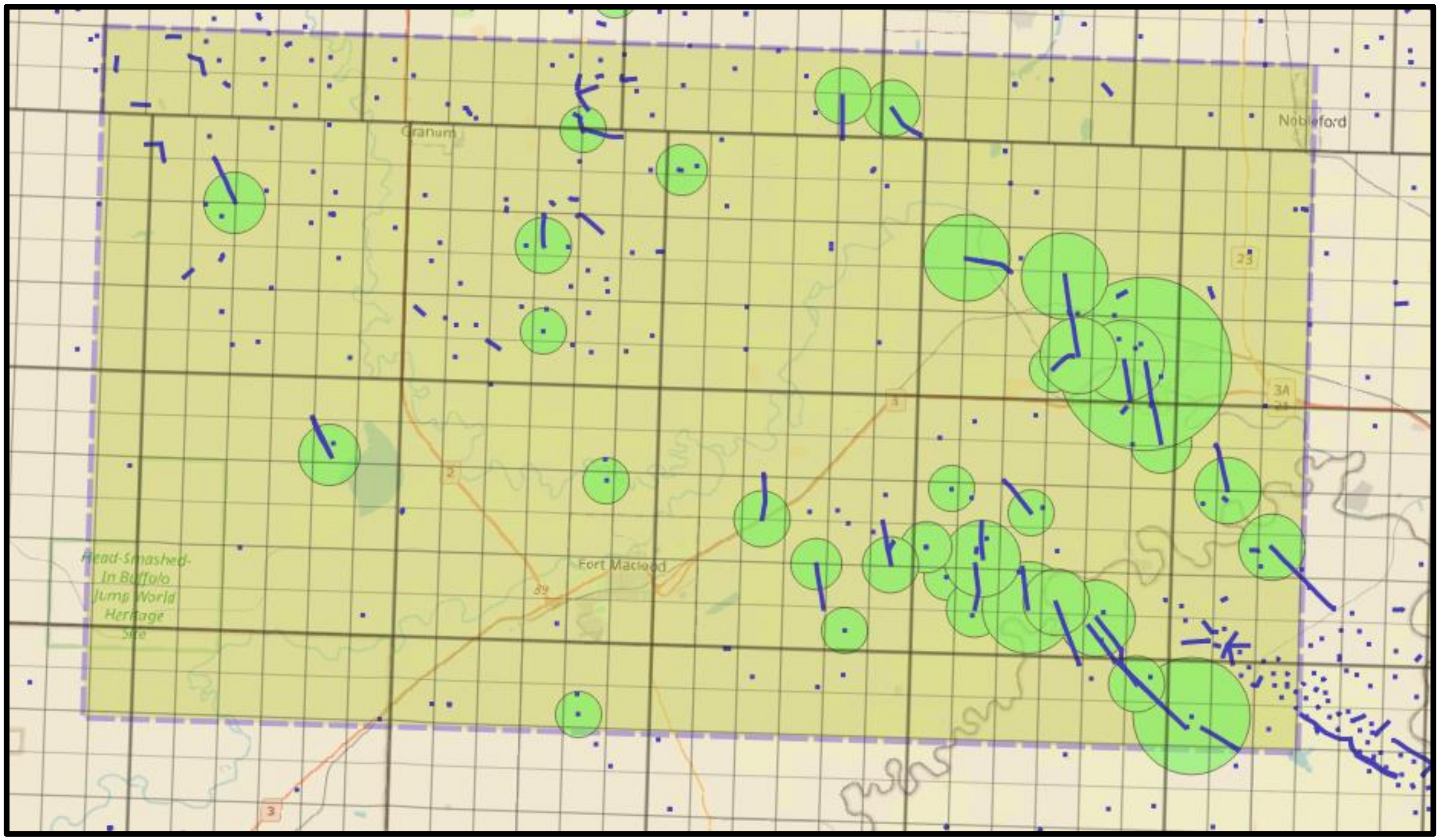
Tuktu owns <u>167 gross sections (161 net sections),</u> mostly in light oil-prone reservoirs in the deep basin[(1)]



(1) Plays I and 2 are part of Acquisition 3, which was announced on October 18 , 2023 and closed on May 27, 2024. Some of the lands are also part of a farm-in agreement announced July 17, 2024.

Southern Alberta Deep Basin: Repeatable light oil drilling inventory

- Recently announced oil discovery is within an over-pressured, deep basin envelope that is up to 250 m thick
- "Bakken" and Banff reservoirs feature variable, cumulative production volumes related to reservoir quality and to fracture distribution along certain faults and associated folds
- These faults are interpreted to have also influenced the recently announced, productive oil well
- Due to the team's past drilling experience in complex foothills fractured reservoirs, the Company is well positioned to exploit these reservoirs
- About 50% of the held or option land in this map are anticipated to be influenced by such faults

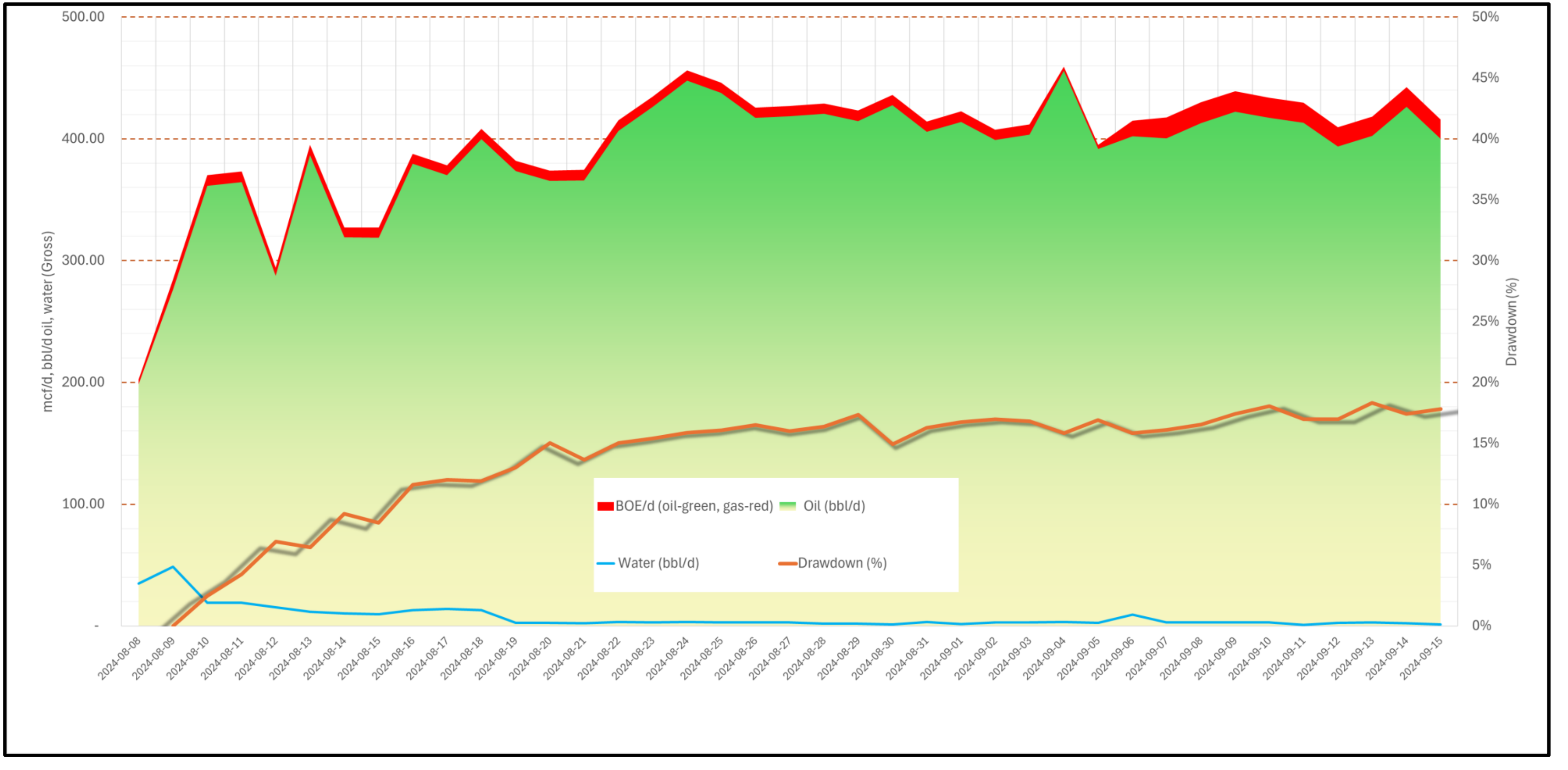


Well production spots of the Mississippian Banff and "Bakken" reservoirs

Tuktu Deep Basin assets; Tuktu has access to 135 gross sections within this polygon

39 days of production history on Tuktu's Deep Basin oil discovery

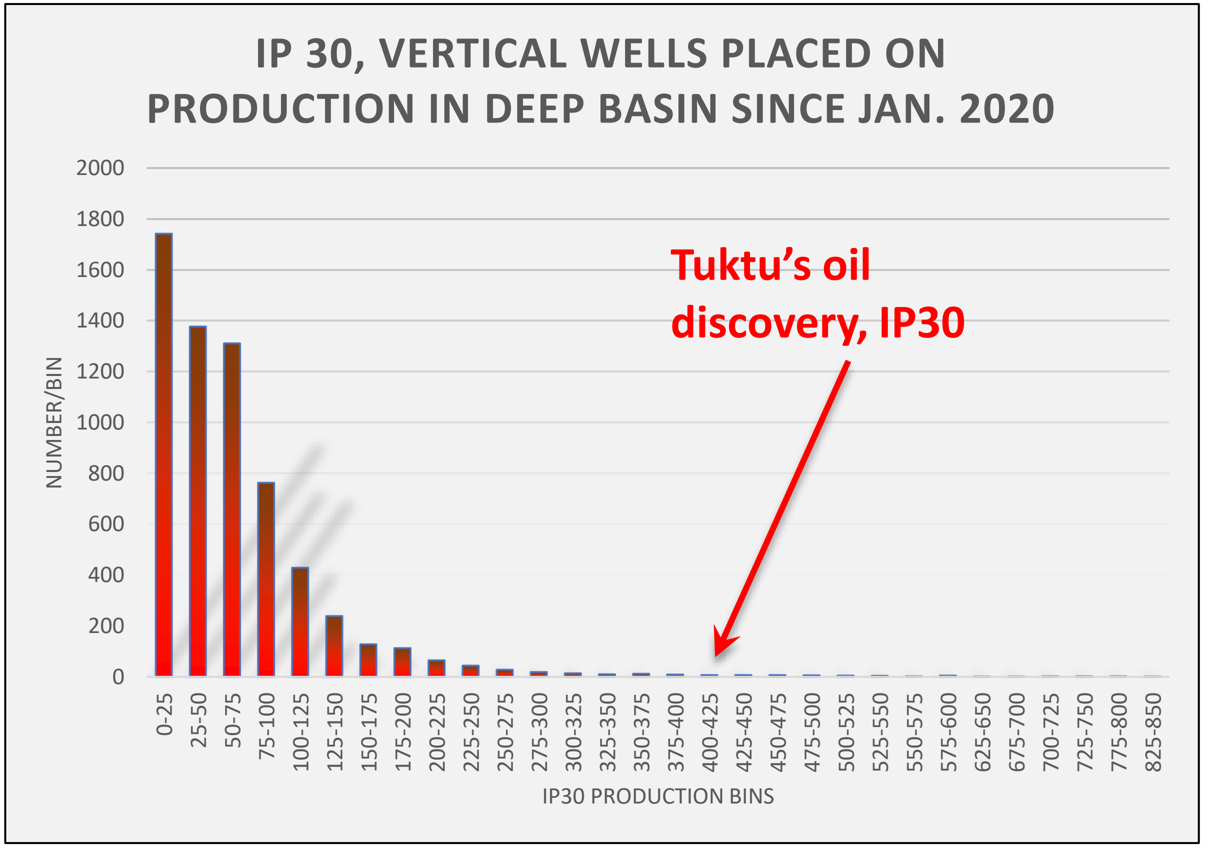
- Vertical, stimulated well bore (25-ton slick water frac)
- Sustained production under rod pump with minimal decline over the first 39 days (**15.3 Mbbl produced** during that time)[1]
- 31.5 API oil
- Less than 20% draw-down (**appears rate constrained due to pump capacity**)
- 3% gas on a BOE basis, and 1-2% water;
- Sustained production implies high permeability reservoir (matrix permeability, perhaps augmented by fractures)
- The Company plans to drill offset wells along fracture-enhanced permeability fairways (FEPF), which are expected to produce significantly more than vertical wells—potentially yielding 2 to 5 times the production capacity of traditional vertical wells.



(1) Please see *"Advisories – Oil and Gas Advisories – Initial Production Rates"*.

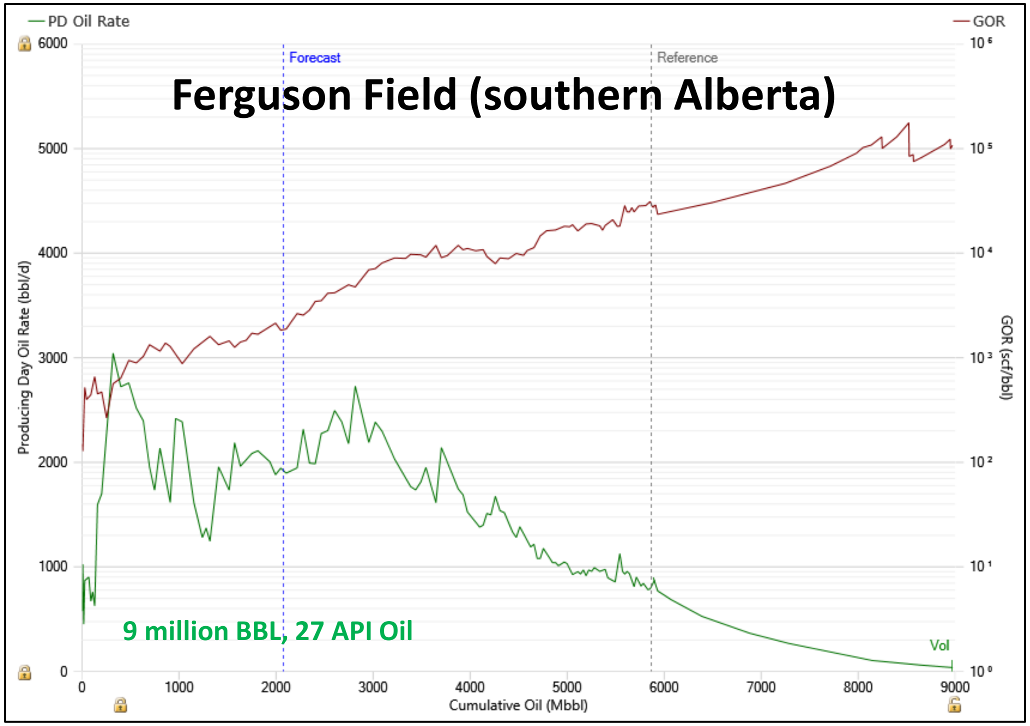
Discovery ranks amongst the top 1% of IP30 for vertical wells placed on production in the Deep Basin since January 2020

- Tuktu's vertical discovery ranks in the **top 1%** of all vertical wells drilled in the Deep Basin since January 2020, with an IP30[1] of >400 bbls/d
- Production profile suggests high reservoir permeability related to fractures and/or matrix permeability (i.e., a conventional reservoir)
- The team anticipates that numerous offset locations exist in the 26.5 sections of land held or controlled by Tuktu in the area



(1) Please see *"Advisories – Oil and Gas Advisories – Initial Production Rates". Data on vertical well IP30 rates are from* GeoScout. *IP30 rates of* in situ *or Sag D bitumen wells have been excluded from the population of 6,355 wells.*

Tuktu – Oil Discovery Analogues in the Alberta Basin



9 million BBL, 27 API Oil

Ferguson Field ***(approx. values)*** (1,2)

Fully developed field

Active Wells: 43

Ave Por: 9%

Thickness: 12m

Initial Pressure: 10,200 kpa

Average Depth: 1290 m

Pressure gradient: 7.8 kpa/m

API: 27.2 API

Original ~GOR: 2800 cf/bbl

Comparable results to Ferguson or Cessford?

Penny Banff ***(approx. values)*** (1,2)

Undeveloped, mostly Tuktu

Active Well: 1

Ave Por: 9%

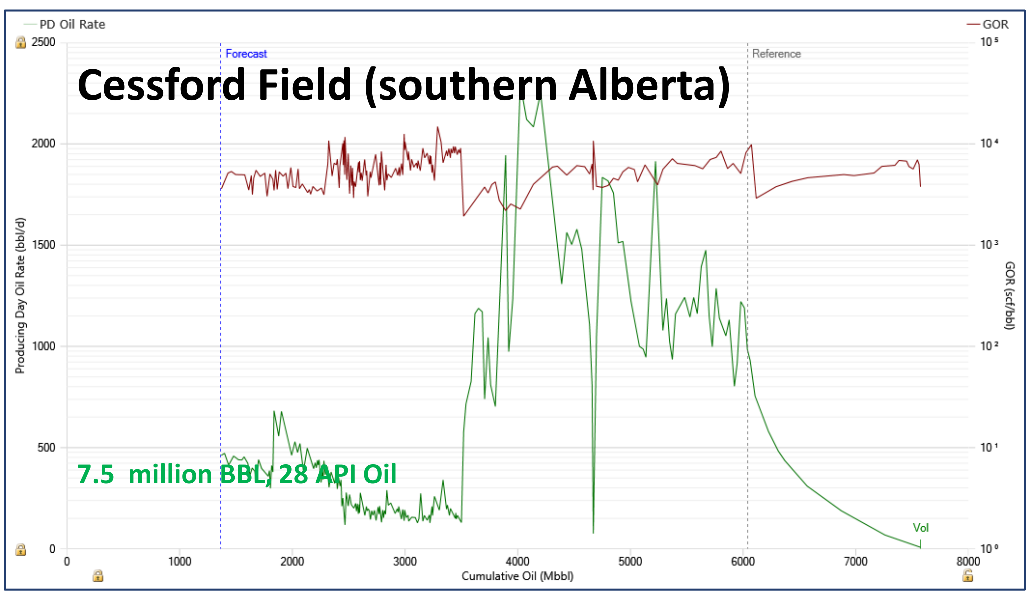
Thickness: 5 m

Anticipated Initial Pressure: 28,300 kpa (2)

Average Depth: 2005 m

Pressure gradient: 14.0 kpa/m (3)

API: 31-33 API



7.5 million BBL, 28 API Oil

Cessford Field (1,2)

Fully developed field

Active Wells: 55

Ave Por: 8.5%

Thickness: 4.2 m

Initial Pressure: 6,600 kpa (2)

Average Depth: 1,350 m

Pressure gradient: 7 kpa/m

API: 28 API

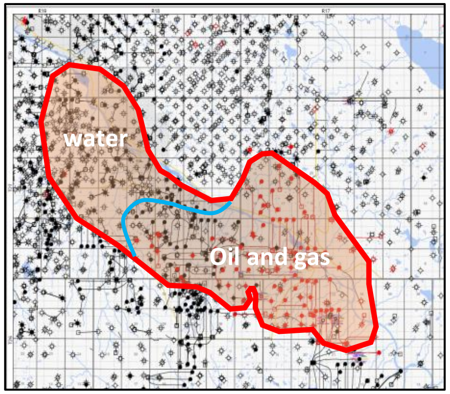
(1) Based on Geoscout data; oil production forward projections are mathematical fits of current and historic production and declined it to an acceptable minimum production level; these numbers should not be interpreted as reserves of such fields and they are estimates only.

(2) The Penny Banff has very few well intersections and only one producing well; there is much greater uncertainty on these values as compared to the numbers for Cessford and Ferguson, which are fully developed fields. Also, the later fields are partly under waterflood.

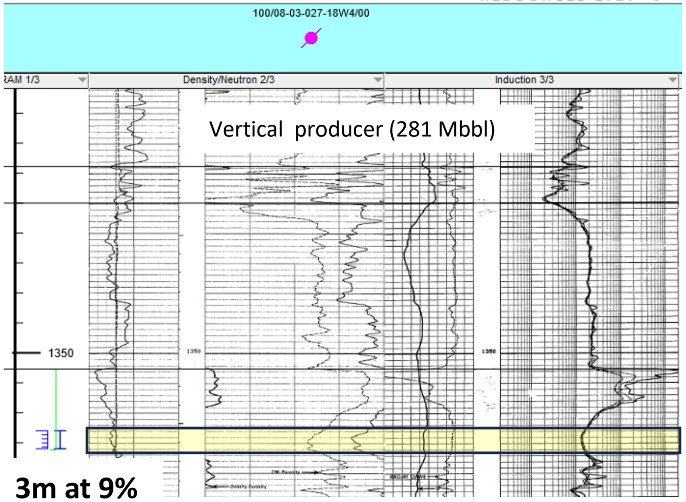
(3) Based on drilling data.

Banff Reservoir: A comparison with Tuktu's Play 1

Cessford

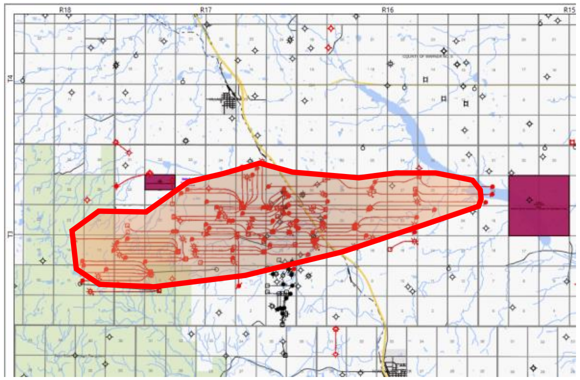


53 sections (33,606 acres; 13,600 ha)
7.5 Million Bbls (1)

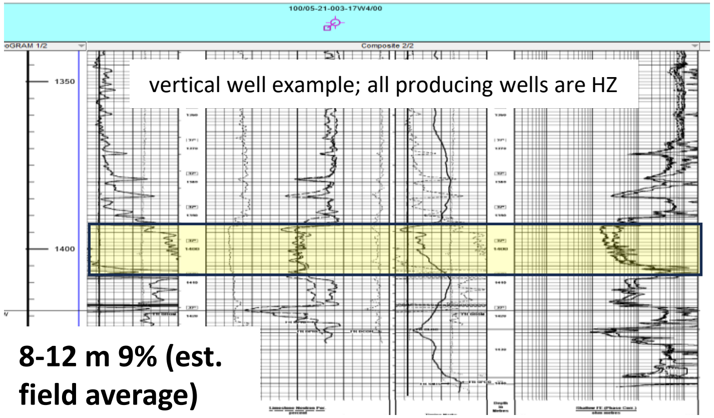


3m at 9%

Ferguson

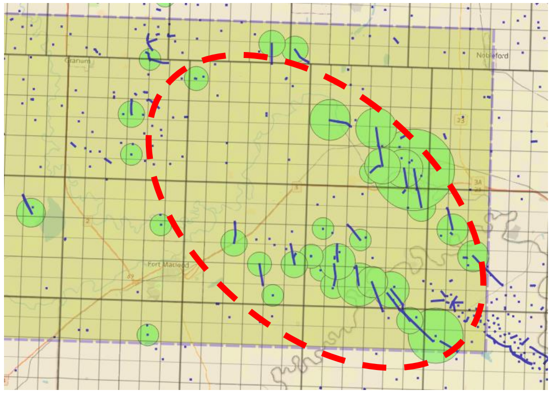


44 sections (27,923 acres; 11,300 ha)
9 millions Bbls (1)



8-12 m 9% (est. field average)

Tuktu, deep basin



52 sections(2) (33,112 acres; 13,400 ha)

Comparable to Ferguson or Cessford pools?
The Tuktu deep basin play is the only reservoir of the 3 examples that has significant fracture-related permeability enhancement; as well as overpressure

3 m 9-12%(3)

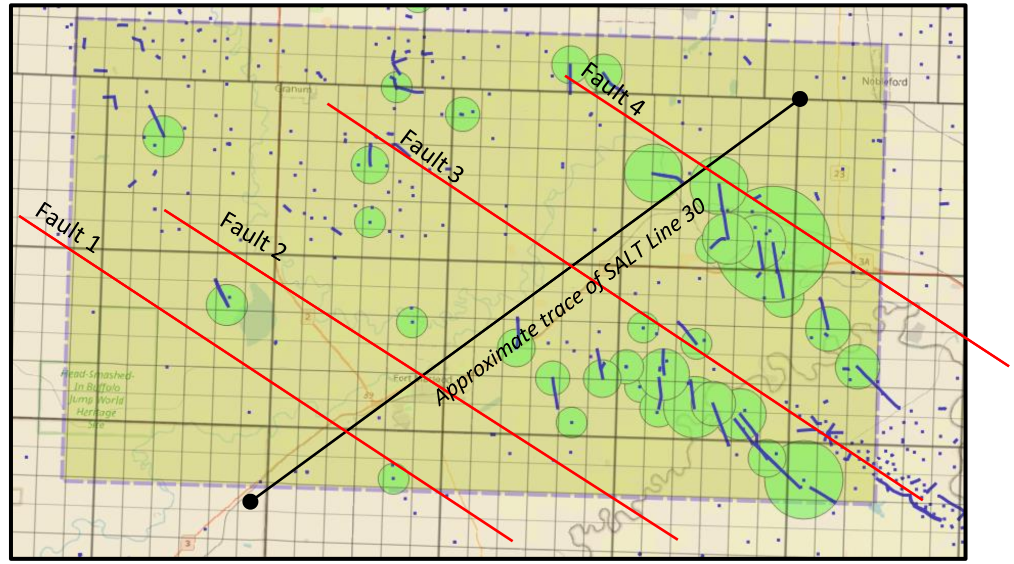
(1) All log and cumulative production data is from GeoScout; estimates of future production of the two fields are described in the previous slide.
(2) TUK currently owns approx. 39% and after full earning under its farmout with a private Co.: approx. 51% (on a gross acreage basis) see "Advisories - Pro Forma Development Plan".
(3) Limited well penetrations/undeveloped.

Banff Reservoir: Structural influence on Play 2

An early mover with a competitive advantage in a producing play

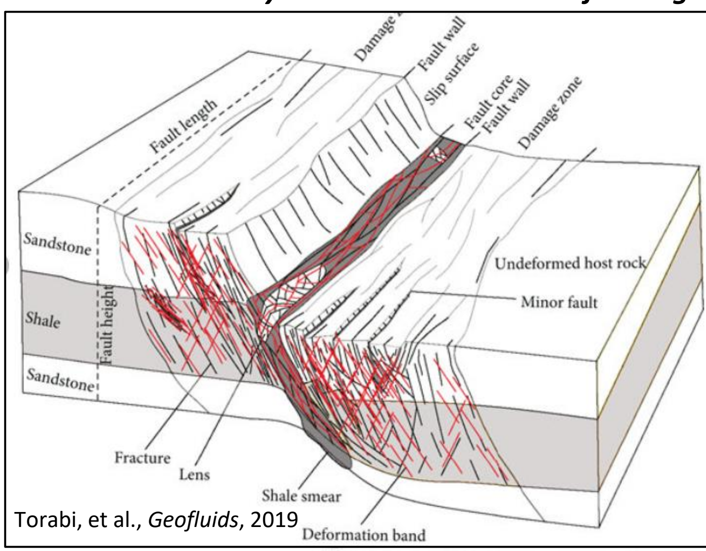
- Some wells purchased in Acquisition 3 have produced over 400 Mbbl [(1)] due to enhanced natural fracture fairways that developed due to foothills-related compression and a reactivated normal fault network.
- Total thickness of oil charge in the deep basin is approximately 250 m, in an overpressured (up to 17 kpa/m) envelope with no apparent water.
- Tuktu team is positioned to leverage their foothills drilling and completion experience to exploit such fracture fairways.
- Anticipated HZ wells are expected to greatly exceed those of the vertical well, as has been demonstrated many times in the basin (*e.g.*, Cardium, Montney, Wilrich reservoirs)

Schematic fault array to demonstrate enhanced permeability fairways across land base [(2)]

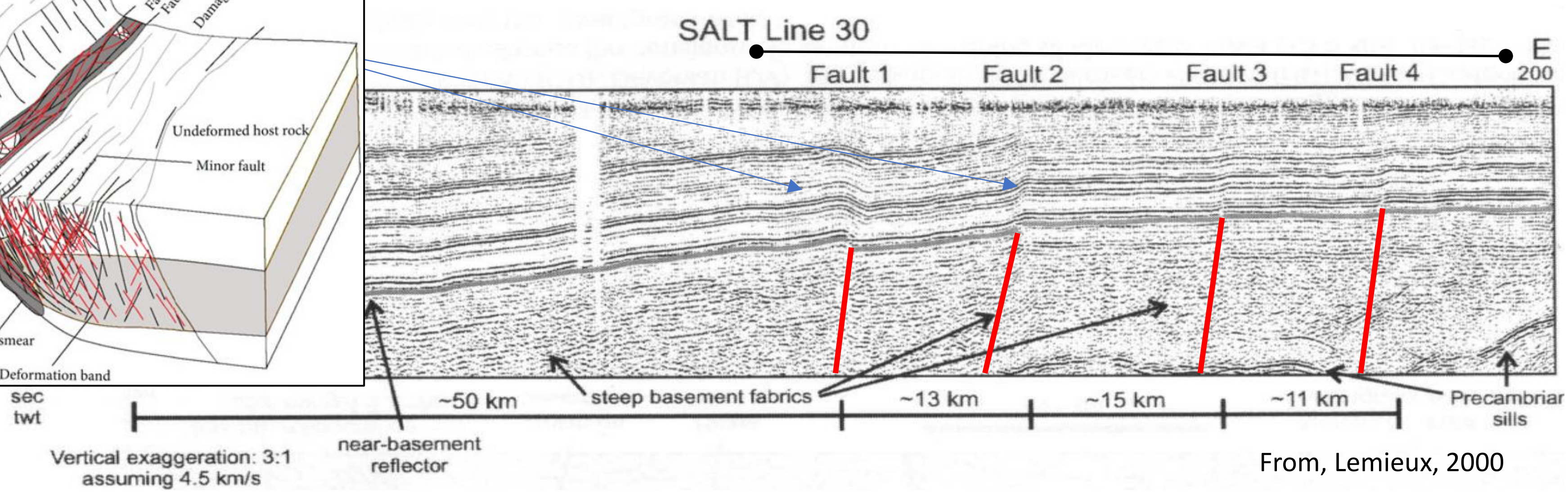


- *Fracture intensity and position relative to faults and fracture fairways has been shown to yield exception well results.*
- *Tuktu will use their foothills drilling and completion experience to develop a repeatable play that is anticipated to be highly economic.*

Fracture intensity related to extensional faulting



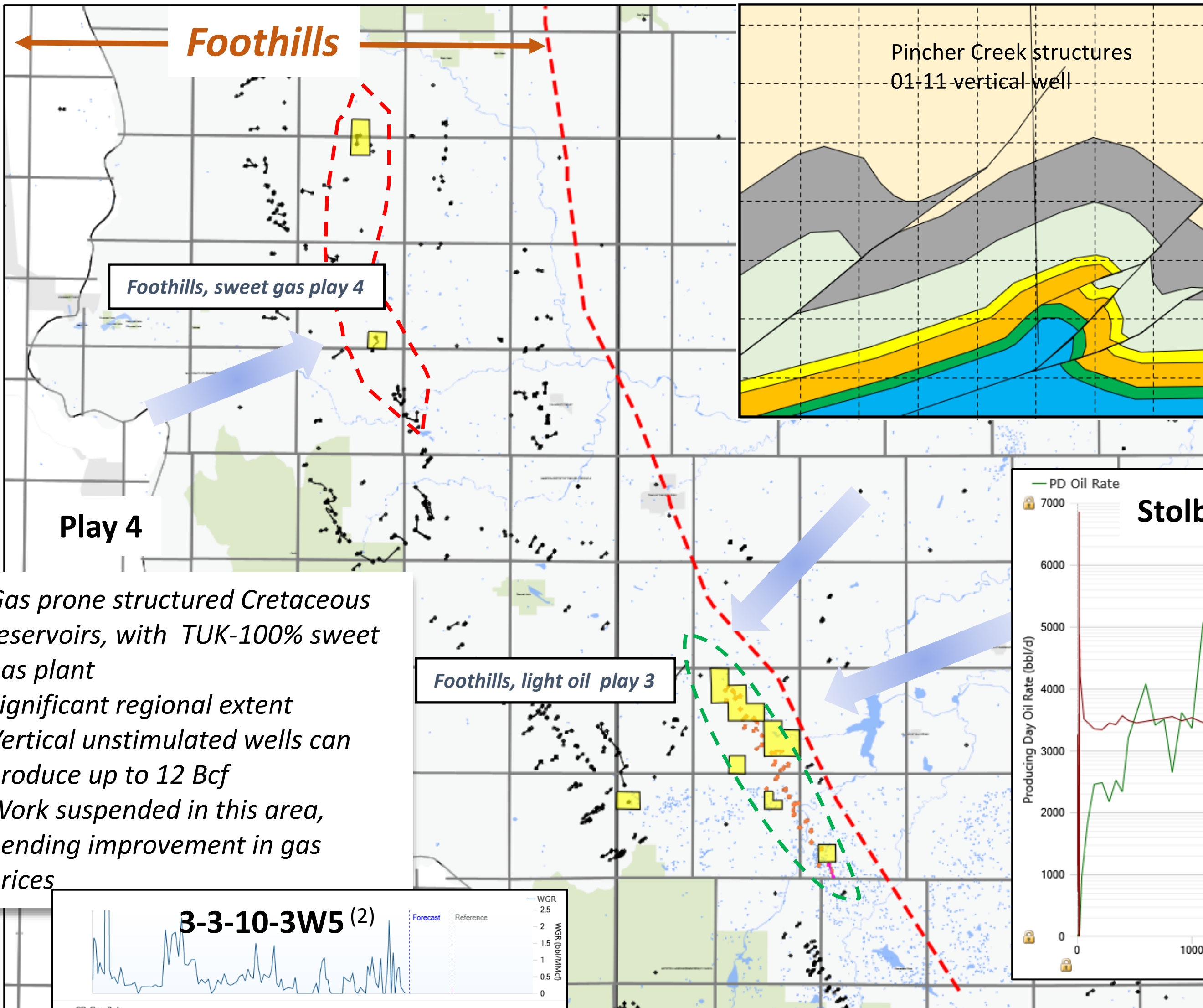
Torabi, et al., *Geofluids*, 2019



From, Lemieux, 2000

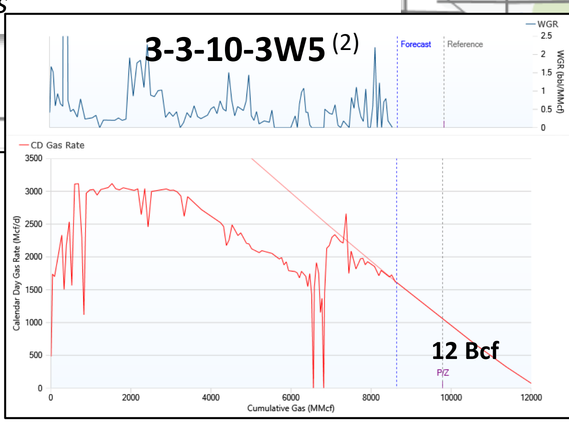
(1) *Based on GeoScout data.*
(2) *Lands shown as Tuktu lands are the subject of Acquisition 3, closed in escrow and awaiting license transfer approval from the AER.*

Other fairways within Tuktu's portfolio: Plays 3 and 4



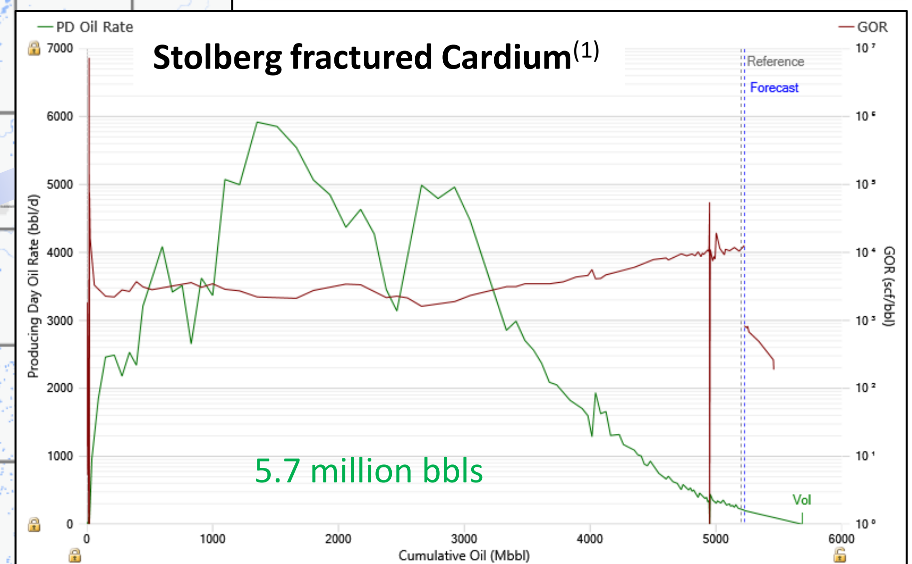
Play 4

- *Gas prone structured Cretaceous reservoirs, with TUK-100% sweet gas plant*
- *Significant regional extent*
- *Vertical unstimulated wells can produce up to 12 Bcf*
- *Work suspended in this area, pending improvement in gas prices*



Play 3

- *Fractured reservoirs in leading fold structures yield exceptional results*
- *In a report by TD issued during the Stolberg drilling (2010), analysts concluded these to be the most economic Cardium wells in the basin at that time.*
- *Pincher Creek structure is significantly larger and has higher reservoir pressure*
- *40-50 API oil*
- *Company anticipates installing artificial lift on the current free flowing well on the structure*



(1) Oil production forward projections are mathematical fits of current and historic production and declined to an acceptable minimum production level; these numbers should not be interpreted as reserves of such fields and they are estimates only.
(2) In the latest reserve report on this asset by GLJ, (YE 2022) and disclosed by Tuktu on March 21st, 2023, an EUR of 12.5 Bcf was assigned to the 3-3-10-3W5 well on a PDP basis.

Development Plan

Post-Acquisition[1] Q4 2024 - Q2 2025

- $ 1-2 million expenditure
- Well workovers and recompletions; (First recompletion resulted in light oil discovery)
- Pump/tubing replacements and installation of artificial lift in one or more wells

Q2 2025 – Q4 2025 [1]

Total CAPEX[2,3] of $2 - 6MM

- Ongoing well workovers and artificial lift installation of wells which flow intermittently
- Possible drill re-entries of existing well bores
- Drill-from-surface 1 -2 HZ wells along fractured fairway, offsetting current discovery well, pending adequate cash from operations.

2025-2027[4]

- Ongoing drilling of deep basin light inventory
- Execute Horizontal oil well in other light oil pools, targeting fracture fairways similar to those of the deep basin light oil discovery

(1) This refers to the completion of: (i) Acquisition 1, pursuant to which Tuktu acquired certain oil properties in Pincher Creek in March 2023; (ii) Acquisition 2, pursuant to which Tuktu acquired certain natural gas properties in Southern Alberta in April 2023; and (iii) Acquisition 3, pursuant to which Tuktu acquired certain oil properties in Southern Alberta in May 2024.

(2) Estimated risked and unrisked initial rates and declines of individual well rates are based on similar operations conducted by the management team in areas featuring reservoir characteristics and structural configuration similar to the target asset. Initial rates and declines of each recompletion or workover are also based on risked and unrisked results of wells completed nearby in the same reservoirs or on reservoirs elsewhere in the foothills and nearby Deep Basin. See "*Advisories – Oil and Gas Advisories – Analogous Information*". These assumptions are subjective and the results of the development plan may not yield the projected results. Also, all projects are subject to further technical and economic due diligence and board approval of an anticipated *pro forma* budget. Peak corporate net production rates will also depend on the timing of contemplated recompletion and workover projects.

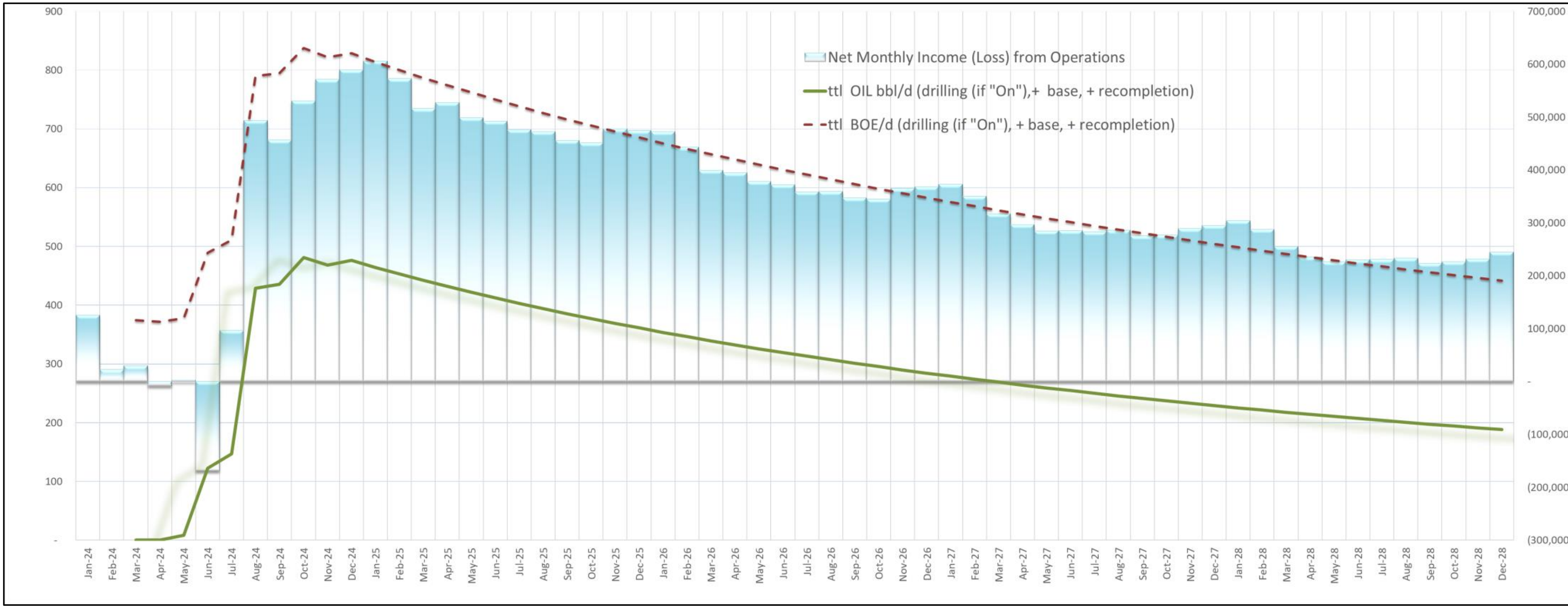
(3) Non-GAAP financial measure. See "*Advisories – Non-GAAP and Other Financial Measures*". Some of the anticipated CAPEX could occur earlier or later in 2024, depending on project timing and fundraising.

(4) Inclusive of the $1.35 million raised by Tuktu pursuant to a brokered private placement completed in May, 2024 (the "**Unit Financing**"); however, additional funds will need to be raised for Tuktu's capital expenditure program. Net proceeds from the Unit Financing are expected to be used to fund development projects on Tuktu's existing properties and assets (however, the company may reallocate certain funds, from time to time, to working capital purposes, as the Company deems necessary or appropriate).

(5) See "*Advisories – Pro-Forma Development Plan*".

Development Plan (1)

Recompletion/workover/re-entry program – *production adds*



(1) *See "Advisories – Oil and Gas Advisories – Initial Production Rates"; "Advisories – Forward Looking Information Advisories – Pro Forma Development Plan"*

Current Capitalization

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	Current
Stock Price [1]	$0.12
Basic Shares (MM)	142.9
Market Capitalization ($MM)	**$17.1**
Working Capital [2]	$0.7
Enterprise Value ($MM)[3]	**$17.8**

Options	MM	Price	Proceeds(MM)	Expiry
	1.00	$0.08	$0.08	03/23/2027
	4.65	$0.15	$0.70	07/25/2027
	0.95	$0.15	$0.14	12/13/2027
	6.00	$0.05	$0.30	07/17/2029
Total	**12.6**	**$0.10**	**$1.22**	

Warrants	MM	Price	Proceeds (MM)	Expiry
Acquisition (Mar 2023)	10.0	$0.300	$3.00	03/17/2026
Financing (Jul 2022)	51.9	$0.110	$5.71	07/15/2026
Financing (Dec 2023)	31.9	$0.075	$2.39	12/28/2026
Financing (May 2024)	28.0	$0.075	$2.10	05/28/2027
Total	**121.8**	**$0.108**	**$13.20**	

Broker Warrants	MM	Price	Proceeds (MM)	Expiry
Financing (Dec 2023)	1.4	$0.05	$0.07	12/28/2026
Financing (May 2024)	1.9	$0.05	$0.10	05/28/2027
Total	**3.3**	**$0.05**	**$0.17**	

(1) As of September 25, 2024
(2) As of June 30, 2024.
(3) See *"Advisories – Non-GAAP Financial Measures and Ratios"*.

Background: Management Team

Tim De Freitas *President, CEO & Director*	• **25+ years experience**, including the founding of five previous oil and gas companies with assets both in Canada and globally, with direct experience in the Foothills via Talisman Energy Inc. ("**Talisman**") and Ikkuma, in addition to a breadth of experience at British Gas and ExxonMobil prior thereto. • Previous experience in both CEO and COO roles, with an educational background in mathematics, geology, and geophysics.	
Mark Smith *VP, Finance & CFO*	• Chartered Professional Accountant with **20+ years experience** in oil and gas companies. • Prior experience in CFO roles including the start-up and management of E&P, midstream and royalty companies both domestically and internationally.	
Greg Feltham *VP, Exploration*	• **20+ years experience** in structural exploration and development, specializing in fractured reservoirs. • Prior experience within the original Talisman Foothills team, including being involved in a number of acquisitions and drilling of >50 horizontal Foothills wells in the Western Canada Sedimentary Basin.	
Kent Busby *VP, Production*	• **30+ years experience** in central Alberta, focused in both construction and oilfield operations, including the management of >200 field employees. • Member of the current technical/operations team for 10+ years, with various field roles at Pieridae Energy Ltd ("**Pieridae**"), Ikkuma, and Manitok, inclusive of managing three large deep cut gas plants and merging Shell's field operations into Pieridae.	
Sumir Saini *VP, Land & Business Development*	• **20+ years experience**, in various management, land & business development roles. • Most recently, President of Empire Oil Corp. Previously Vice President, Land of Mount Bastion Oil & Gas Corp. and prior thereto, held various roles of increasing responsibility at Bellatrix Exploration Ltd. (and its predecessor, True Energy Trust). • Involved in >$1 billion in M&A transactions.	

Background: Corporate Governance

Tuktu RESOURCES LTD.

Bob Dales
Chairman of the Board

- Bob Dales was founder and co-founder of Kelt Exploration Ltd., Celtic Exploration Ltd., Peyto Exploration and Development Corp., Amarok Energy Inc., and Manitok, with decades of public company experience in the oil and gas sector at both the executive and board level. Bob was the Chairman of Ikkuma Resources Corp.

Kathleen Dixon
Director

- Kathleen Dixon, PGeo, MBA is a former Director with BMO Capital Markets ("**BMO**") in the Acquisitions and Divestitures group where during her 13 years, was part of over $20 billion in energy sector transactions. In 2019, Kathleen took a leave of absence to run as a candidate in Vancouver for the Conservative Party of Canada. After the election, she returned to BMO and completed her ICD.D designation. Kathleen currently sits on three private company and not-for-profit boards.

William Guinan
Director

- William C. (Bill) Guinan practiced law primarily at Borden Ladner Gervais LLP from 1982 until 2021. He has extensive experience with corporate governance and corporate finance matters as well as with mergers and acquisitions transactions, serving as director and as corporate secretary for numerous public and private corporations over the last 30 years. He holds a Bachelor of Business Administration from Acadia University (1977) and an MBA and LLB from Dalhousie University (1982).

Natalie Sweet
Director

- Natalie L. Sweet is a Professional Geologist with 25 years of exploration and development experience in the petroleum industry. She has held senior technical and leadership roles at several public and private corporations including Penn West Exploration Ltd., Apache Canada Ltd. and Mount Bastion Oil and Gas Corp. Ms. Sweet holds a Bachelor of Science in Geology from Queen's University (1991) and a Master of Science in Earth Sciences from the University of Ottawa (1995).

Note: Tim de Freitas (Director) listed on prior page.

Background: About Tuktu Resources Ltd.

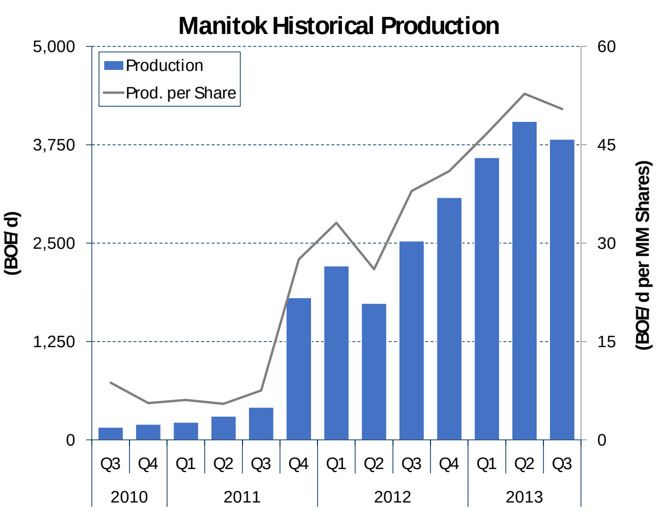
Experienced Management Team	• **Industry leading technical and operational team with direct experience owning and developing profitable assets.** • Team has successfully executed a junior growth model twice previously at Manitok Energy Corp. ("**Manitok**") and Ikkuma Resources Corp. ("**Ikkuma**"). • Team is ideally positioned to operate Foothills and Deep Basin assets to drive long-term shareholder value.
Foothills & Deep Basin Consolidation Opportunity	• **Attractively priced consolidation opportunities exist within the Alberta Foothills and Deep Basin with considerable free cash flow and resource upside.** • Due to the exodus from into unconventional plays, previous operators have left underexploited reservoirs and under-utilized infrastructure providing an advantage and cost savings for a junior growth company. • Parts of the southern Alberta Deep Basin with a high structural component amenable to exploitation skills developed in the foothills. • The lack of recent development drilling has left Foothills facilities and pipelines underfilled. Operators have plenty of processing capacity and egress for new gas.
Clean Corporate Entity, Attractive Foothills Oil-Prone Acreage	• Meaningful investment from insiders • Debt-free company • Minimal asset retirement obligations after giving effect to the previously announced acquisitions of assets from an arm's length, private company ("**Acquisition 1**") and an arm's length company ("**Acquisition 2 and Acquisition 3**") (1) • *Pro forma*, the Company has identified **100-120 drilling locations** across **four independent play types** on the acquired land base: 30 locations targeting sweet gas and oil within the foothills and 70-90 locations targeting oil in the adjacent deep basin.(2) The former 30 horizontal well locations are akin to fields previously developed in the Foothills by the Tuktu management team (*e.g.*, Stolberg).(3)

(1) Specifics of Acquisition 1 were announced December 8, 2022 and specifics of Acquisition 2 and Acquisition 3 were announced March 21, 2023, and October 18, 2023, respectively.
(2) See "*Advisories – Oil and Gas Advisories – Drilling Locations*".
(3) See "*Advisories – Oil and Gas Advisories – Analogous Information*".

Background: Track Record of Success of Tuktu Team Members

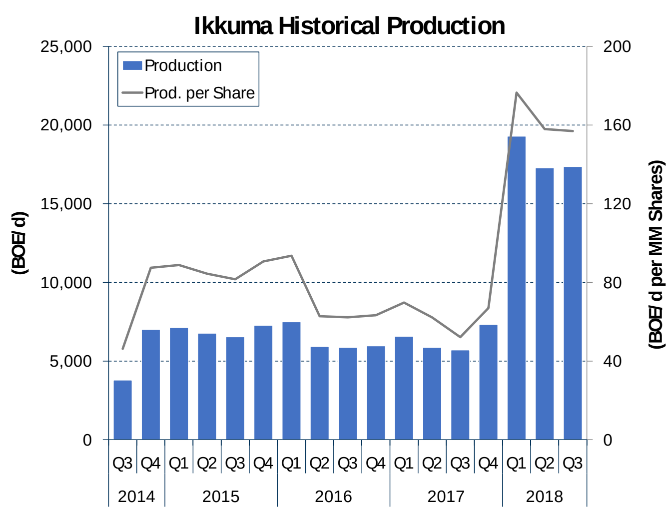
July 2010 to Oct. 2013

- **Went public via an amalgamation with private company, previously having raised $18MM in equity via private placements since being founded in 2005, with Mr. de Freitas serving as VP, Exploration and COO.**
- Completed a number of acquisitions and undertook meaningful exploration and development activities within the Central and Southern Alberta Foothills.
- Manitok was focused on both heavy oil, and Foothills natural gas, in many of the same areas where the Tuktu team is currently targeting M&A.



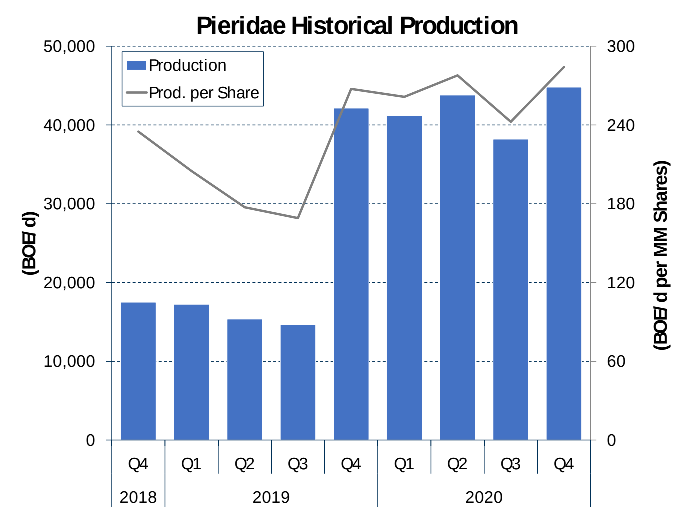
May 2014 to Dec. 2018

- **Went public via a reverse take-over of a public company, with a concurrent $20MM private placement, and a rights offering to existing public company shareholders.**
- Ikkuma subsequently undertook a successful $120MM asset acquisition in the Foothills region funded with a $130MM bought equity deal.
- The team would complete a number of additional acquisitions and equity raises, until Ikkuma was ultimately sold to Pieridae in December 2018 (~300% premium to VWAP). The team additionally negotiated a spin out transaction as part of the sale, driving incremental value for all shareholders.



Dec. 2018 to Jan. 2021

- **Mr. de Freitas, in addition to other members of the Tuktu team, joined Pieridae at the closing of the Ikkuma transaction and remained with the company as it undertook the transformational Shell Foothills acquisition in 2019.**
- The Foothills transaction closed in late-2019, adding ~28,000 BOE/d in the Alberta Foothills, in addition to a number of facilities, for a total purchase price of $190MM. The Tuktu team was integral throughout the acquisition and subsequent integration.



Note: Historical Production Graphs prepared by Stifel Nicolas Canada Inc.

Background: Acquisition 3 Metrics

Purchase Price ("**P**")(1,6)	$3MM	
Adjusted Purchase Price(2)	$1.5MM	
Adjusted Purchase Price/2023 Estimated Annualized NOI(3,6,7)	0.7 X	
12 Month Trailing Operating Expenses	$33.95/bbl	
2023E Production(3)	165 bbl/d	
2023 Est. Annualized NOI(3,8)	$2.2MM	
Cost Per Flowing Barrel (P/(bbl/d))(4,5,11)	$18,182	
Trailing production decline	16%	
Reserves	**MMbbl(9,12)**	**NPV10% ($MM) (9,10,12)**
PDP	0.3	$5.50
Proven + Probable	2.1	$19.60
Reserves	**P/MMbbl(9,11,12)**	**P/NPV10%(9,10,11,12)**
PDP	$9.75	55%
Proven + Probable	$1.44	15%

(1) Prior to interim or final adjustments.
(2) The Adjusted Purchase Price is the purchase price of $3.0 million less estimated interim adjustments of approximately $1.5 million, based on nine months of adjustments.
(3) Based on vendor's books and records or a projection of such records, as applicable, with an asset decline of 16% and September 20, 2023 strip pricing.
(4) May to July 2023, average production, based on the vendor's lease operating statements.
(5) Calculated using the purchase price/current production
(6) The components of the purchase price (prior to any adjustments) are allocated as follows: (i) $2.4 million to petroleum and natural gas rights; (ii) $599,990 to tangibles; and (iii) $10.00 to miscellaneous interests and seismic rights.
(7) Non-GAAP ratio. See "*Advisories – Non-GAAP and Other Financial Measures*".
(8) Non-GAAP financial measure. See "Advisories – *Non-GAAP and Other Financial Measures*".
(9) Based on the Acquisition 3 Reserves Report. Assumes unadjusted purchase price. See "*Advisories – Oil and Gas Advisories – Reserves Information*".
(10) NPV10% means the net present value of future net revenue before income tax discounted at 10%. This metric does not represent the fair market value of the Assets. See "*Oil and Gas Advisories – Reserves Information*".
(11) Supplementary financial measure. See "*Non-GAAP and Other Financial Measures*".
(12) See "*Oil and Gas Advisories – Abbreviations*".

Advisories

All amounts in this document are stated in Canadian dollars unless otherwise specified.

FORWARD-LOOKING INFORMATION ADVISORIES

Certain information contained in this document may constitute forward-looking statements and information (collectively, "forward-looking statements") within the meaning of applicable securities legislation that involve known and unknown risks, assumptions, uncertainties and other factors. Forward-looking statements may be identified by words like "anticipates", "estimates", "expects", "indicates", "intends", "may", "could" "should", "would", "plans", "target", "scheduled", "projects", "outlook", "proposed", "potential", "will", "seek" and similar expressions. Forward-looking statements in this document include, among other things, statements about: Tuktu Resources Ltd. (“**Tuktu**” or the “**Company**”) and its business strategy, strengths, focus and objectives; the anticipated annual decline of the Company’s assets (including recently acquired assets); financial and operating forecasts with respect to the Company’s assets; that the Company will be able to implement a well workover/recompletion program and the anticipated production growth resulting therefrom; projections with respect to operating expenditures and capital expenditures; pro forma company asset metrics; pro forma capitalization expectations; targets with respects to growth following Acquisition 3; anticipated pro forma drilling locations; expectations with respect to raising future capital; expectations with respect to funding and approval of the Company's pro forma development plan; expectations that a development drilling program will follow the Company's recompletion plan and the timing thereof; NOI per expected outstanding share amounts; and other similar statements. Such statements reflect the current views of management of the Company with respect to future events and are subject to certain risks, uncertainties and assumptions that could cause results to differ materially from those expressed in the forward-looking statements.

Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable crude oil, natural gas and NGL reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially. For these reasons, estimates of the economically recoverable crude oil, NGL and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Tuktu's actual production (including production from recently acquired assets), revenues, taxes and development and operating expenditures with respect to their respective reserves will vary from estimates thereof and such variations could be material.

With respect to forward-looking statements contained in this document, the Company has made assumption as specifically detailed throughout this document and assumptions regarding, among other things: that the Company will be able to raise adequate funds in the future; the geological characteristics of Tuktu’s properties, including recently-acquired assets; the success of future drilling, development and completion activities; future commodity pricing and related supply demand; future exchange, inflation, and interest rates; that the Company will be able to exploit the Mississippian aged reservoirs in the land base; that the Company will be able to successfully implement a well workover/recompletion program to increase production; the receipt and timing of regulatory and other required approvals; and operating costs and capital expenditures.

Factors that could cause actual results to vary from forward-looking statements or may affect the operations, performance, development and results of the Company's businesses include, among other things: risks and assumptions associated with operations; the Company's ability to raise future funds including the ability of the Company to fund its pro forma development plan; risks inherent in the Company's future operations; the Company's ability to generate sufficient cash flow from operations to meet its future obligations; the Company's ability to exploit the Mississippian aged reservoirs in the land base; the Company's ability to implement a well workover/recompletion program to increase production; risks regarding the Company's ability to reduce operating costs and increase production; increases in maintenance, operating or financing costs; the realization of the anticipated benefits of future acquisitions, if any; the availability and price of labour, equipment and materials; competitive factors, including competition from third parties in the areas in which the Company intends to operate, pricing pressures and supply and demand in the oil and gas industry; fluctuations in currency and interest rates; inflation; risks of war, hostilities, civil insurrection, pandemics, instability and political and economic conditions in or affecting countries in which the Company intends to operate (including the ongoing Russian-Ukrainian and Israeli-Hamas conflicts); inclement and severe weather events and natural disasters; terrorist threats; risks associated with technology; risks associated with the oil and gas industry in general; changes in laws and regulations, including environmental, regulatory and taxation laws, and the interpretation of such changes to the management team's future business; availability of adequate levels of insurance; difficulty in obtaining necessary regulatory approvals and the maintenance of such approvals; general economic and business conditions and markets; and such other similar risks and uncertainties. The impact of any one assumption, risk, uncertainty or other factor on a forward-looking statement cannot be determined with certainty, because these are interdependent, and the Company's future course of action depends on the assessment of all current available information.

The forward-looking statements contained in this document are made as of the date hereof and the parties do not undertake any obligation to update or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws. These and other risks are set out in more detail in Tuktu’s annual information form for the year ended December 31, 2023 (“**AIF**”) and Tuktu’s most recent annual and interim management discussion and analysis (“**MD&A**”). The Company’s AIF and MD&A can be accessed under Tuktu’s SEDAR+ profile at www.sedarplus.ca.

THIRD PARTY INFORMATION

Certain market, third party and industry data contained in this presentation is based upon information from government or other industry publications and reports or based on estimates derived from such publications and reports. Government and industry publications and reports generally indicate that they have obtained their information from sources believed to be reliable, but the Company has not conducted its own independent verification of such information. No representation or warranty of any kind, express or implied, is made by the Company as to the accuracy or completeness of the information contained in this document, and nothing contained in this report is, or shall be relied upon as, a promise or re-report by the Company.

Advisories

PRO FORMA DEVELOPMENT PLAN

The Company has presented herein an illustrative pro-forma development plan (the "**Development Plan**") in respect of Tuktu's assets, including the assets acquired pursuant to Acquisition 1, Acquisition 2 and Acquisition 3 (as further described on Slide 13). The Development Plan is based on a number of assumptions including, without limitation: the required reinvestment rates to maintain production; the Company's ability to raise future funds; expected recovery factors; average production per year resulting from such development plan; expected cash flow and free cash flow; capital expenditures per year; expectations as to commodity prices, royalty rates, production costs, general and administrative expenses and certain other assumptions. The Development Plan has not been approved by the Board of Directors of the Company and is not intended to present a forecast of future performance or a financial outlook. In addition, the Development Plan does not represent management's expectations of the Company's future performance but rather is intended to present readers insight into management's view of opportunities available to Tuktu as of the date of this document, as used by management for planning and strategy purposes based on the commodity pricing and other assumptions used for such strategy. In addition, the Development Plan does not represent an estimate of reserves or the future net present value of reserves. There is no certainty that the Company will proceed with any of the projects contemplated by the Development Plan , and even if the Company does proceed with such plans, there is no certainty that the oil and gas recovered will match the expectations used for such plan. All future capital expenditures will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, debt levels, actual drilling results, additional reservoir information that is obtained, and other factors. The assumptions used for the plan presented herein are subject to a number of risks including the risks set out under the forward-looking advisory set out above.

The Company continues to negotiate a land arrangement with adjacent landowners on the newly acquired land (Acquisition 3); there can be no guarantee that such lands can be successfully acquired until the final points of this agreement are negotiated. If the land agreement cannot be completed in a timely manner or in a manner that is beneficial to both parties, this does not comprise the company's ability to execute on its capital program.

FORWARD LOOKING FINANCIAL INFORMATION

This document contains future-oriented financial information and financial outlook information (collectively, "**FLFI**") about the Development Plan, anticipated capital expenditures in 2024 and 2025, prospective operational and financial results of the Company's assets, all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth in the above paragraphs. FLFI contained in this document was made as of the date of this document and was provided for the purpose of providing further information about the Company's future business operations, the Company disclaims any intention or obligation to update or revise any FLFI contained in this document, whether as a result of new information, future events or otherwise, unless required pursuant to applicable securities laws. Readers are cautioned that the FLFI contained in this document should not be used for purposes other than for which it is disclosed herein.

NON-GAAP AND OTHER FINANCIAL MEASURES

This document uses various specified financial measures (as such terms are defined in National Instrument 52-112 – *Non-GAAP Disclosure and Other Financial Measures Disclosure* ("**NI 51-112**")) including "non-GAAP financial measures", "non-GAAP ratios" and "supplementary financial measures" (as such terms are defined in NI 51-112), which are described in further detail below. Management believes that the presentation of these non-GAAP measures provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis. These non-GAAP and other financial measures are not standardized financial measures under IFRS and might not be comparable to similar measures presented by other companies where similar terminology is used. Investors are cautioned that these measures should not be construed as alternatives to or more meaningful than the most directly comparable IFRS measures as indicators of the Company's performance.

Non-GAAP Financial Measures and Ratios

- *Net Operating Income ("**NOI**"), non-GAAP financial measure*

Management feels net operating income is a key industry benchmark and measure of operating performance of the Company that assists management and investors in assessing the Company's profitability and is commonly used by other petroleum and natural gas producers. Net operating income is calculated as petroleum and natural gas revenue less royalties, transportation and operating expenses.

- *Net Asset Value ("**NAV**"), non-GAAP financial measure*

Management feels net asset value is a key industry benchmark and measure of operating performance of the Company that assists management and investors in assessing the Company's profitability and is commonly used by other petroleum and natural gas producers. Net asset value is calculated as the Company's working capital plus its 2P reserve values.

- *Enterprise Value, non-GAAP financial measure*

The Company uses "enterprise value" as a key performance indicator. Enterprise value is calculated by adding the Company's market capitalization and market value of the Company's outstanding debt, less any cash or cash equivalents.

- *Debt Adjusted Cash Flow ("**DACF**"), non-GAAP financial measure*

The Company considers DACF a key industry benchmark and measure of operating performance of the Company. DACF is calculated by the Company as funds flow plus financing costs.

Advisories

- *NOI/Share, non-GAAP ratio*

Management considers NOI/Share a key performance measure of the Company. NOI/Share is determined by dividing NOI by the shares outstanding on an undiluted basis.

- *Enterprise Value to Debt Adjusted Cash Flow ("**EV/DACF**"), non-GAAP ratio*

Management considers EV/DACF a standard industry benchmark and key performance indicator as it is a key metric used to evaluate the sustainability of the Company relative to other companies while incorporating the impact of differing capital structures. EV/DACF is calculated by the Company as enterprise value divided by debt-adjusted cash flow for the relevant period.

- *Price/NAV, non-GAAP ratio*

Management considers Price/NAV a key performance measure of the Company. Price/NAV is determined by dividing the price of an asset by the NAV.

- *Adjusted Purchase Price/2023 Estimated Annualized NOI, non-GAAP ratio*

Management considers Adjusted Purchase Price/2023 Estimated Annualized NOI a key performance metric for Acquisition 3. Adjusted Purchase Price/2023 Estimated Annualized NOI is determined by dividing the purchase price for Acquisition 3, as adjusted, by 2023 estimated annualized NOI**.**

Supplementary financial measures

This document may contain certain supplementary financial measures. NI 52-112 defines a supplementary financial measure as a financial measure that: (i) is intended to be disclosed on a periodic basis to depict the historical or expected future financial performance, financial position or cash flow of an entity; (ii) is not disclosed in the financial statements of the entity; (iii) is not a non-GAAP financial measure; and (iv) is not a non-GAAP ratio.

The Company calculates "Purchase Price/PDP NPV10%" by dividing the Purchase Price by the net present value of the proved developed producing reserves discounted at 10%, "Purchase Price/Proven NPV10%" by dividing the Purchase Price by the net present value of the proven reserves discounted at 10%, "Purchase Price/Proven + Probable NPV10%" by dividing the Purchase Price by the net present value of the proven and probable developed producing reserves discounted at 10%, "Purchase Price/PDP" by dividing the Purchase Price by the estimated proved developed producing reserves, "Purchase Price/Proven" by dividing the Purchase Price by the estimated proven reserves and "Purchase Price/2P" by dividing the Purchase Price by the estimated total proved plus probable reserves.

OIL AND GAS ADVISORIES

RESERVES INFORMATION: Reserves estimates in this document: (i) in respect of Acquisition 3 are based on the evaluations prepared by GLJ Ltd. ("**GLJ**") as set out in a report dated effective December 31, 2022 with a preparation date of September 1, 2023, evaluating the oil reserves attributable to such assets (the "**Acquisition 3 Reserves Report**"); (ii) in respect of Acquisition 2 are based on evaluations set out in a report prepared by independent reserves evaluator, GLJ dated effective January 1, 2023 (the **"Acquisition 2 Reserves Report**"); and (iii) in respect of Acquisition 1 are based on evaluations as set out in a report prepared by independent reserves evaluator, Chapman Petroleum Engineering Ltd. ("**Chapman**") dated effective June 30, 2022 (the **"Acquisition 1 Reserves Report**"), each of which was prepared in accordance with National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") and the most recent publication of the Canadian Oil and Gas Evaluation Handbook (the "**COGEH**"). The Acquisition 3 Reserves Report was based on the average price and market forecasts of three independent reserves evaluators (GLJ, McDaniel & Associates Consultants Ltd. and Sproule Associates Ltd.) as of January 1, 2023 which is set forth under the heading "Pricing Assumptions" below, the Acquisition 2 Reserves Report was based on the average forecast pricing of GLJ, McDaniel & Associates Consultants Ltd. and Sproule Associates Ltd. as at January 1, 2023 and the Acquisition 1 Reserves Report was based on the average forecast pricing of Chapman and inflation rates and foreign exchange rates as at July 1, 2022. There is no assurance that the forecast prices and costs assumptions will be attained, and variances could be material. The recovery and reserve estimates of the crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

This document contains estimates of the NPV of the Company's future net revenue from reserves associated with the Company's assets (including assets acquired pursuant to recent acquisitions), as applicable. Such amounts do not represent the fair market value of such reserves. The recovery and reserve estimates provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. The NPV of the respective assets' base production is a snapshot in time and is based on the reserves evaluated using the applicable pricing assumptions described above. The NPV is calculated using a discount rate of 10%, on a before tax basis and is the sum of the present value of proved plus probable developed producing reserves based on the applicable pricing assumptions. It should not be assumed that the undiscounted or discounted NPV of future net revenue attributable to the respective assets represents the fair market value of those assets. The estimates for reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties due to the effects of aggregation. The recovery and reserve estimates of crude oil, NGL and natural gas reserves are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates relied upon for NPV calculations, herein.

BOE ADVISORY: The term "BOE" or barrels of oil equivalent may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Additionally, given that the value ratio based on the current price of crude oil, as compared to natural gas, is significantly different from the energy equivalency of 6:1; utilizing a conversion ratio of 6:1 may be misleading as an indication of value.

Advisories

INITIAL PRODUCTION RATES: References in this document to IP or IP30 rates, other short-term production rates or initial performance measures relating to new wells are useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long-term performance or of ultimate recovery. All IP rates presented herein represent the results from wells after all "load" fluids (used in well completion stimulation) have been recovered. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Company. Accordingly, the Company cautions that the test results should be considered to be preliminary.

DRILLING LOCATIONS: This document discloses drilling locations in two categories: (i) booked locations; and (ii) unbooked locations. Booked locations identified in this document reflect drilling locations that have associated proved and/or probable reserves, as applicable, and were derived from: (i) in respect of the assets acquired pursuant to Acquisition 3, from the Acquisition 3 Reserves Report; (ii) in respect of Tuku's assets, the Acquisition 1 Reserves Report. In respect of the assets acquired pursuant to Acquisition 3, of the 70 gross drilling locations identified herein, 6 gross locations are booked locations, and 64 gross locations are unbooked locations. In respect of Tuktu, of the 20+ gross drilling locations identified herein, 4 gross locations are booked locations, and 16+ gross are unbooked locations. Each of the Acquisition 3 Reserves Report, the Acquisition 2 Reserves Report and the Acquisition 3 Reserves Report were prepared in accordance with NI 51-101 and the COGEH. Unbooked drilling locations are the internal estimates of Tuktu based on the prospective acreage of the Tuktu assets (including recently acquired assets), and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by Tuktu's management as an estimation of Tuktu's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that Tuktu will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and natural gas reserves, resources or production. The drilling locations on which Tuktu will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been de-risked by Tuktu drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management of Tuktu 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.

ANALOGOUS INFORMATION & TYPE CURVES: Certain information in this document may constitute "analogous information" as defined in NI 51-101, with respect to Tuktu's assets including, but not limited to, information relating to well locations that are in geographical proximity to or believed to be on-trend with other drilling locations acquired by the Company. This analogous information is derived from publicly available information sources which the Company believes are predominantly independent in nature. Some of this data may not have been prepared by qualified reserves evaluators or auditors and the preparation of any estimates may not be in strict accordance with COGEH. There is no certainty that the results of the analogous information or inferred thereby will be achieved by the Company and such information should not be construed as an estimate of future production levels or the actual characteristics and quality of the Company's assets. Certain type curves disclosure presented herein represents volumes expected to be recovered from wells. The type curves represent what management thinks an average well will achieve, based on methodology that is analogous to wells with similar geological features. Individual wells may be higher or lower but over a larger number of wells, management expects the average to come out to the type curve. Over time, type curves can and will change based on achieving more production history on older wells or more recent completion information on newer wells

OIL AND GAS METRICS: This document contains certain oil and gas metrics, including payout, 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. Payout means the anticipated years of production from a well required to fully pay for the costs associated to drill, complete equip and tie-in a well. Such metrics have been included in this document to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the Company's future performance and future performance may not compare to the Company's performance in previous periods and therefore such metrics should not be unduly relied upon.

PRICING ASSUMPTIONS

	Edmonton Light
	$CAD/bbl
2023	$103.77
2024	$97.74
2025	$95.27
2026	$95.58
2027	$97.07
2028	$99.01
2029	$100.99
2030	$103.01
2031	$105.07
2032	$106.69
2033	$111.00
2034	$113.22
2035	$115.49
2036	$117.80
Escalating at	2%

US DISCLAIMER

This presentation does not constitute an offer of the securities for sale in the United States. The securities have not been registered under the U S Securities Act of 1933 as amended, and may not be offered or sold in the United States absent registration or an exemption from registration. This presentation shall not constitute an offer to sell or the solicitation of an offer to buy nor shall there by any sale of the securities in any state in which such offer, solicitation or sale would be unlawful.

ABBREVIATIONS

Terms and abbreviations that are used in this document that are not otherwise defined herein are provided below:

bbl(s) - barrel(s)
bbls/d - barrels per day
BOE - barrels of oil equivalent (6 Mcf = 1 bbl)
IP30 - initial production over the first 30-days on stream
kpa - kilopascal
Mbbl - thousand barrels of oil
MM - millions
MMbbl - million barrels of oil
Mcf - thousand cubic feet
NPV - net present value
NPV10 - net present value using a 10% discount rate
NGL - natural gas liquids as defined in NI 51-101
PDP - proved developed producing
TPP - total proved plus probable
NOI - net operating income