altura ENERGY INC.

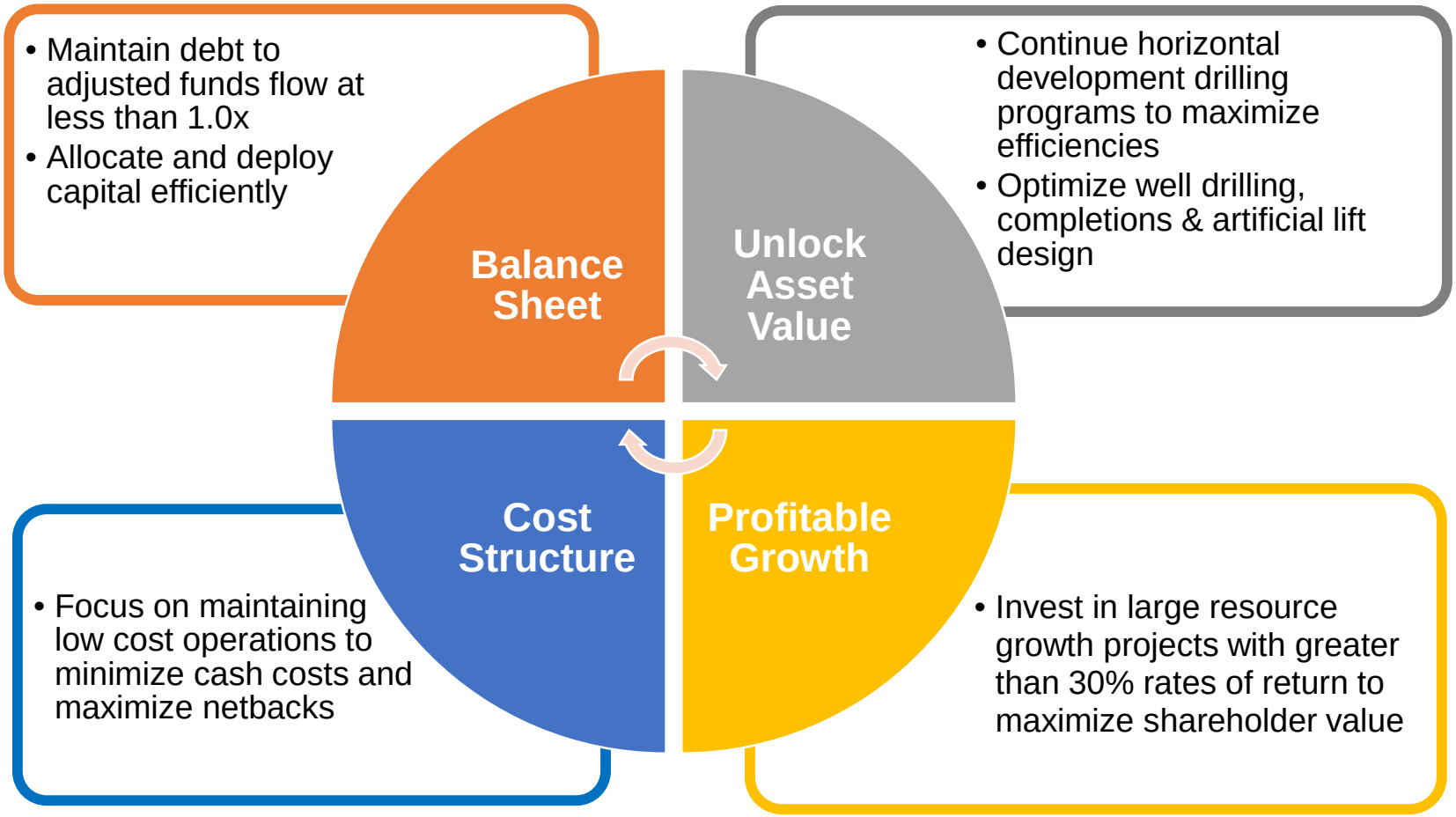
Oil Weighted Company Poised for Growth

APRIL 2021

www.alturaenergy.ca

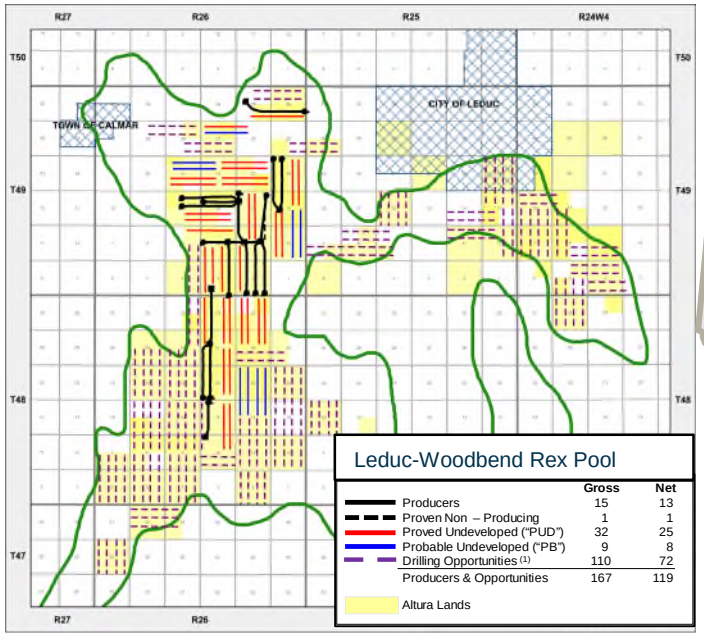
Altura Energy Inc.

- Canadian junior oil company trading under the symbol ATU on the TSX-V
- Focused on large conventional oil resources in early stages of development
- Positioned to unlock asset value with post COVID-19 oil demand recovery
- Opportunity to participate in company growth with crude oil price strengthening



Corporate Overview

Established business with material growth potential	• Commenced Leduc-Woodbend operations in 2016 • Q4/20 production and adjusted funds flow(1) of 916 boe/d(9) and $0.8 million • Established base production with estimated base decline of 28% in 2021 and 21% in 2022 • Growth potential with current inventory of > 5,000 boe/d
Strong Balance Sheet and Clean Asset base	• Year end 2020 net debt(2) of $3.9MM with $9MM total Credit Facilities • Clean asset base with a corporate LMR of 5.08(3) • ARO of only $2.1 million inflated at 2% and discounted at 10%(4)
Leduc-Woodbend Large Resource	• 1,100 MMbbl pool OOIP(5) with 400 MMbbl on Altura's land & 0.9 MMbbl recovered to date • LWB Rex inventory of 151 gross drilling opportunities(6) (47 booked) & ~44,000 gross acres • LWB Rex >70% IRR and 1.3 Year Payout assuming WCS US$40/bbl
Leduc-Woodbend Development Ready	• Development can be scaled up quickly with the use of existing pads and operated facilities • Optimized 1.5 mile Rex horizontal well completion design with 2 casing joint frac spacing



Capitalization

Basic Shares Outstanding	108.9MM
Fully Diluted Shares Outstanding	115.0MM
Market Cap(7) @ $0.155/share	$ 16.9MM
Net Debt(2)	$ 3.9MM
Enterprise Value(8)	$ 20.8MM
Tax Pools at December 31, 2020	$ 43.0MM

Management

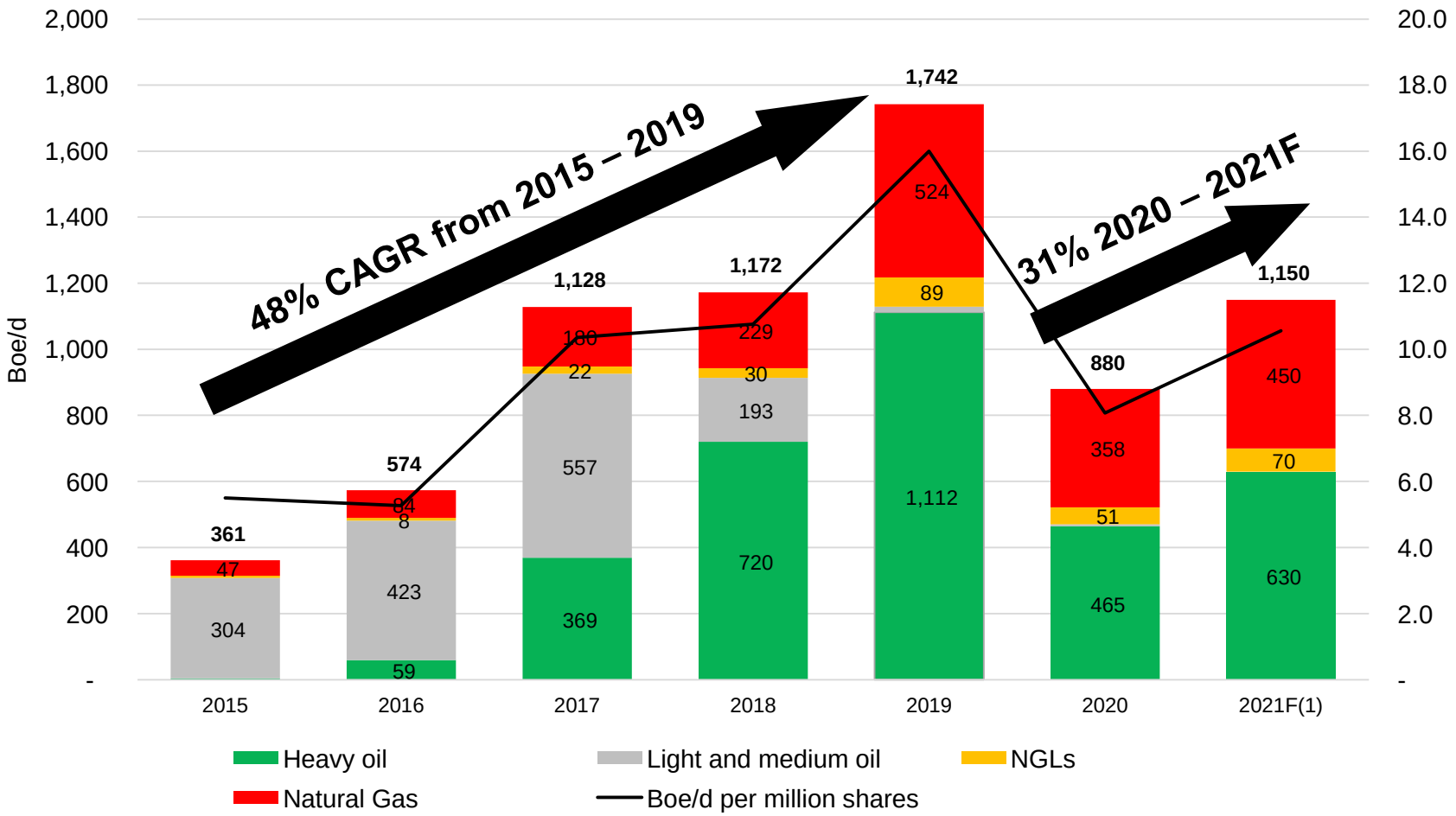
David Burghardt	President & CEO
Tavis Carlson	VP Finance, CFO
Rob Pinckston	VP Exploration
Travis Stephenson	VP Engineering
Jeff Mazurak	VP Operations
Craig Stayura	VP Land

Directors

David Burghardt
John Chambers
Darren Gee
Robert Maitland
John McAleer, Chairman

*Footnotes included at the end of presentation

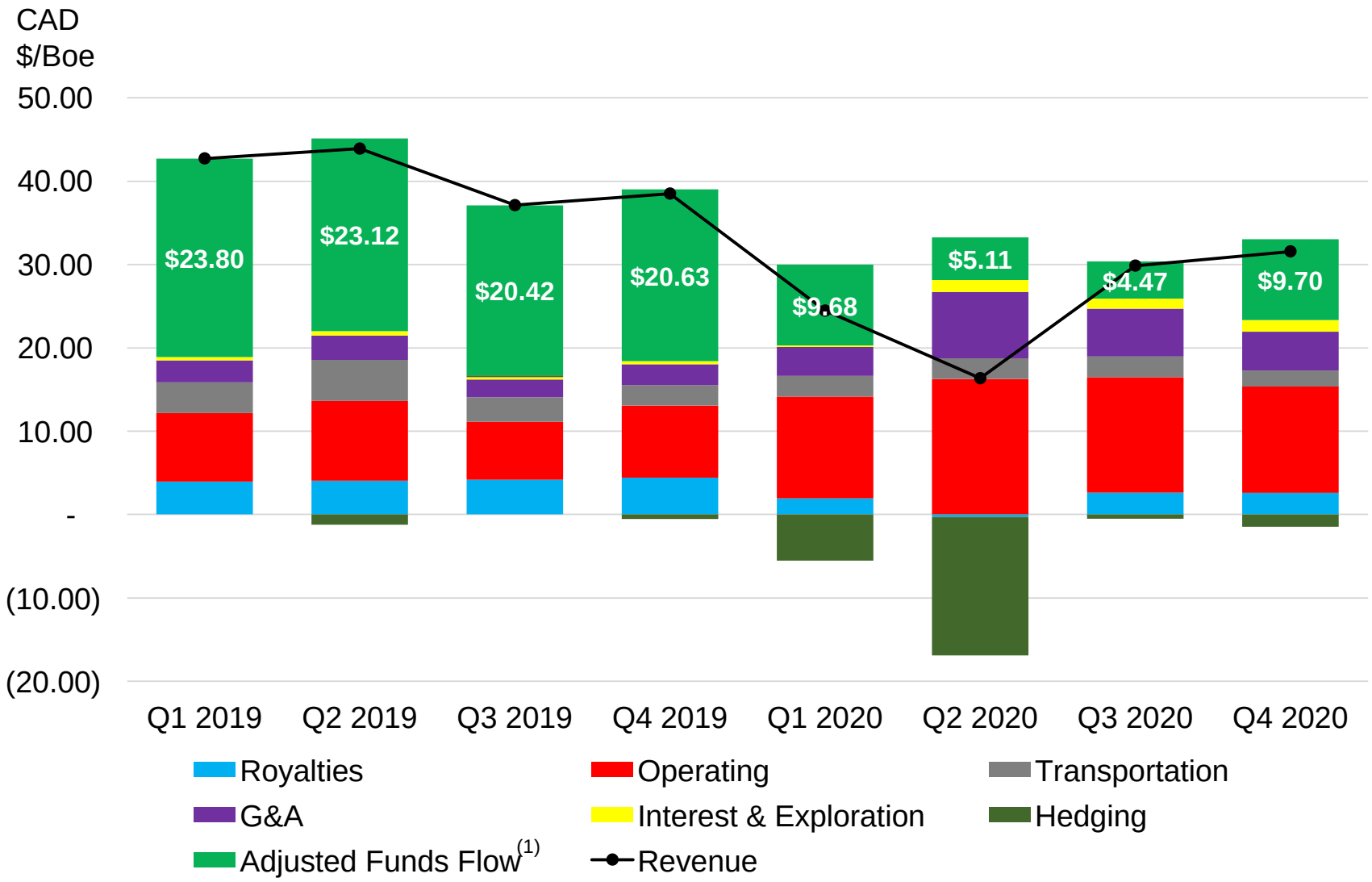
Annual Production Profile



2020 production impacted by oil price crash, industry wide shut-ins and halt in capital spending from COVID-19.

*Footnotes included at the end of presentation

Revenue & Adjusted Funds Flow



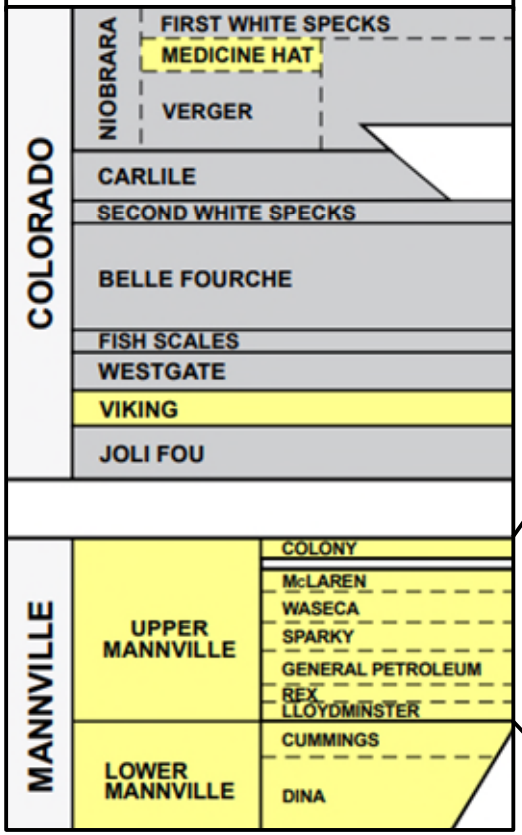
*Footnotes included at the end of presentation

Altura Stratigraphic Focus

altura ENERGY INC.

East-Central Plains

Leduc – Woodbend

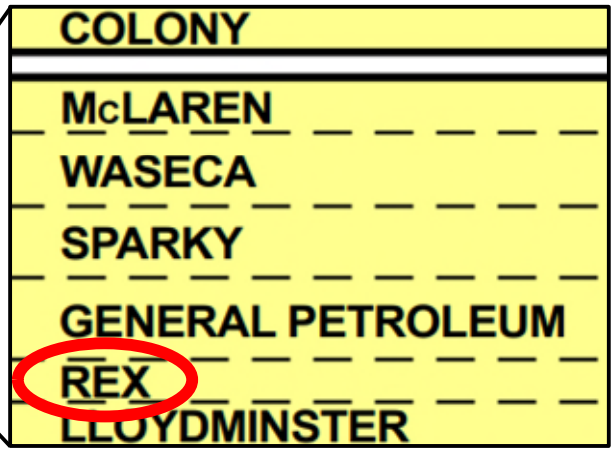


Entice

Pekisko Exploration
1,600 – 1,750m TVD
20 – 35°API oil

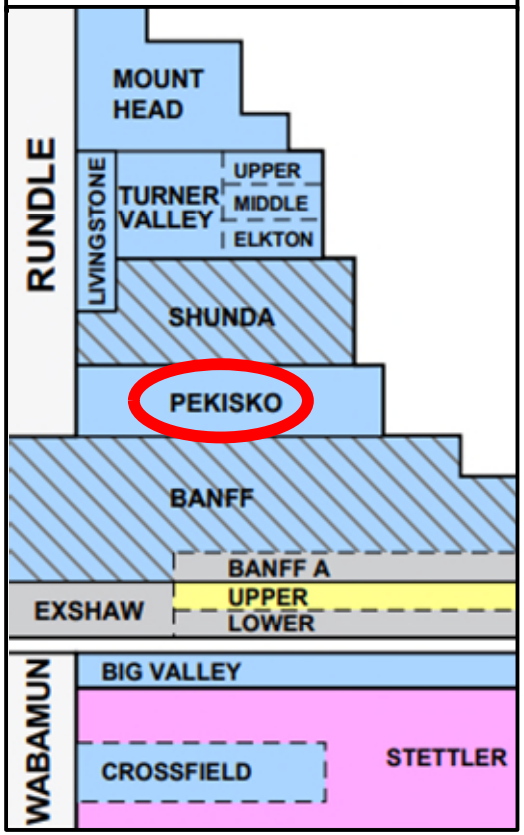
Leduc–Woodbend

Rex Development
~1,300m TVD
17°API oil



Southern Plains

Entice

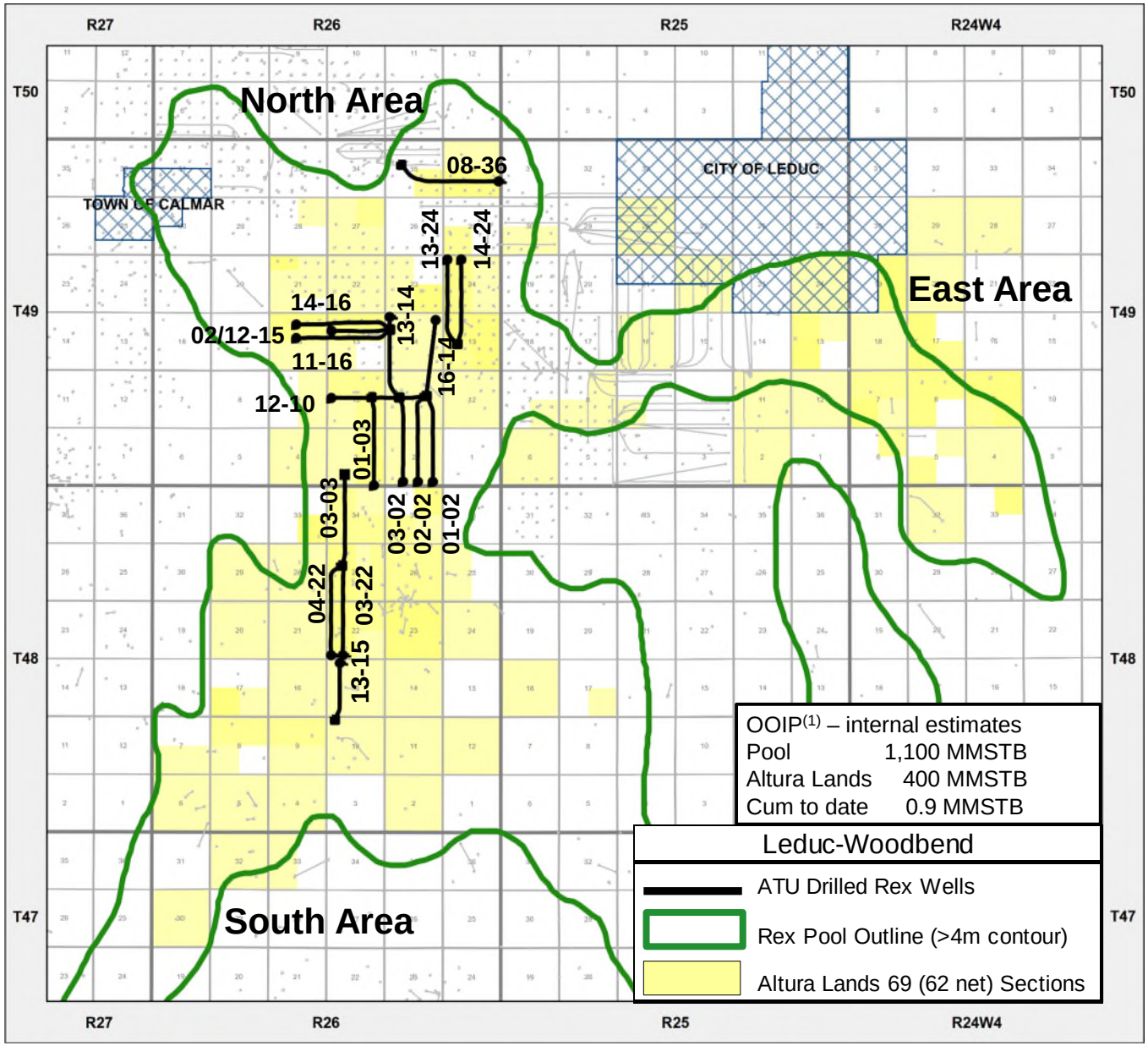


Leduc-Woodbend

Concept	• Early stage, large resource, development play with year-round drilling access • Targeting the Rex member of the Upper Mannville formation at 1,300m TVD • Oil quality 17°API with in-situ viscosity ~35cp
Land	• 44,000 gross acres (40,000 net acres) • 89% average operated working interest • 64% Crown & 36% Freehold tenure
Development	• 1,100 MMbbl pool OOIP(1) • 400 MMbbl on Altura's land • Inventory of 107 drilling opportunities(2) • >115% IRR and 1.0 Year Payout assuming WCS US$45/bbl
Next Technical Steps	• Drill a 2 mile horizontal Rex well • Test the eastern extension of the Rex pool • Test waterflood potential on 400 meter inter-well spacing with unstimulated injector

*Footnotes included at the end of presentation

Leduc-Woodbend Resource Play

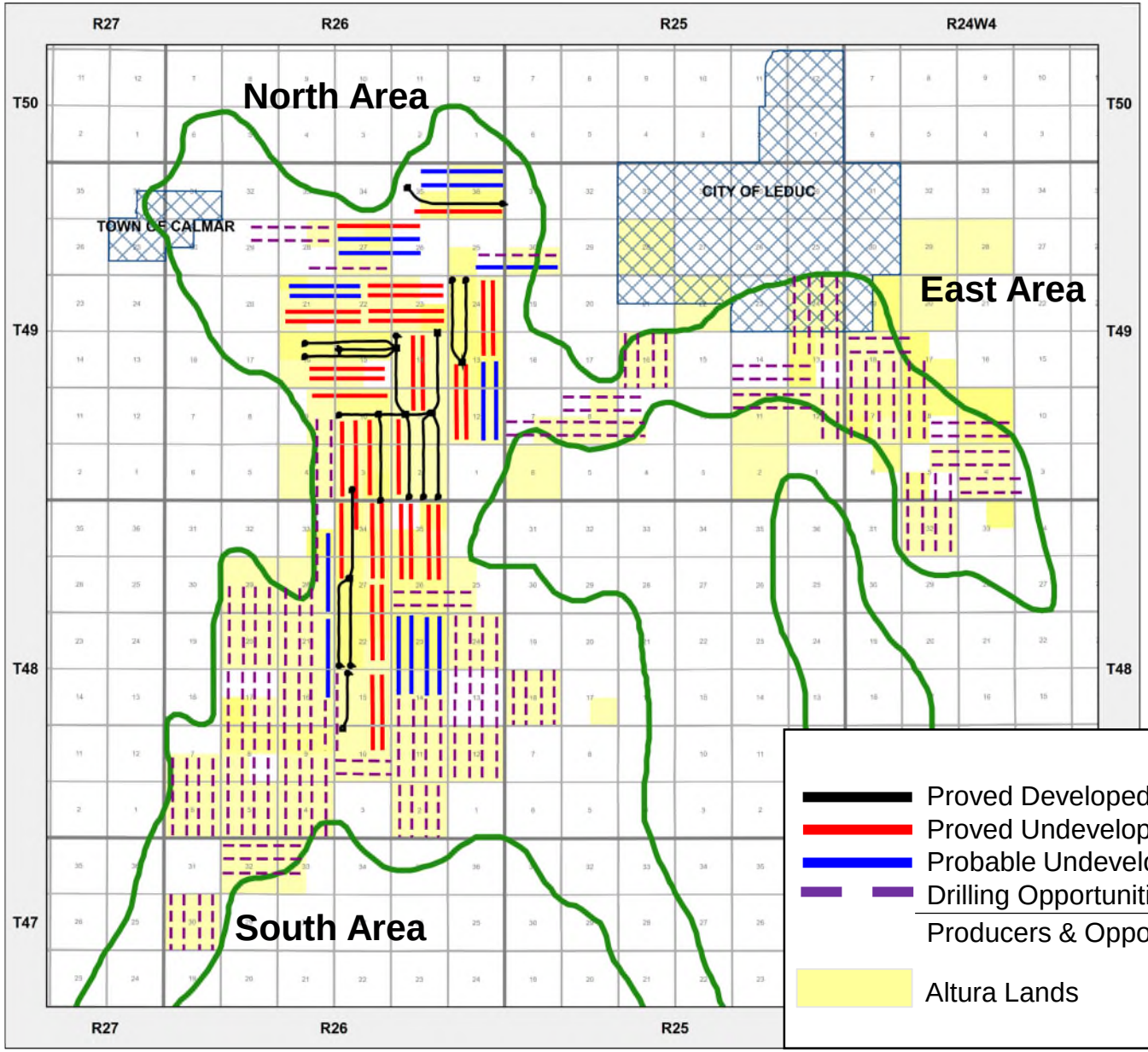


- Targeting the Rex formation, 17˚ API heavy oil at 1,300mTVD
- Approximately 900 vertical wellbore penetrations through the Rex provide excellent geologic control and reservoir definition
- Wells are completed as single leg multi-stage fracture stimulations (Hz MSF) with optimized frac interval density
- Waterflood potential exists to enhance recovery

Large resource in early-stage development

*Footnotes included at the end of presentation

Leduc-Woodbend Drilling Inventory



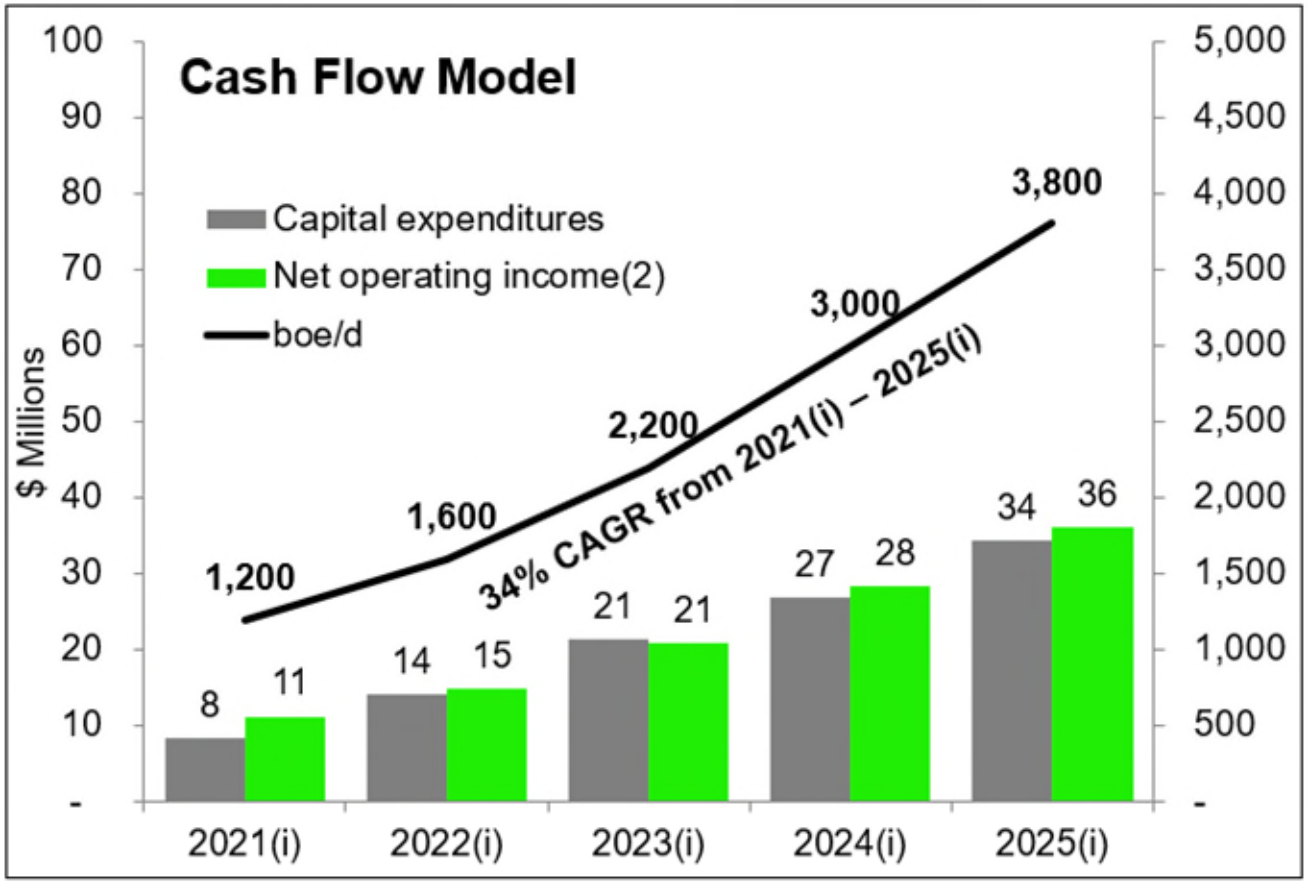
- Current inventory is based on 1.5 mile wells and 400m inter-well spacing
- Over 60% of the inventory is un-booked
- Potential to down space to 200m inter-well spacing
- Waterflood potential exists to enhance recovery

	Gross	Net
Proved Developed	16	14
Proved Undeveloped (“PUD”)	32	25
Probable Undeveloped (“PB”)	15	12
Drilling Opportunities(1)	104	67
Producers & Opportunities	167	118

Altura Lands

*Footnotes included at the end of presentation

Leduc-Woodbend Development Potential



KEY ASSUMPTIONS	2021(i)	2022(i)	2023(i)	2024(i)	2025(i)
WTI (US$/bbl)	60.93	60.00	60.00	60.00	60.00
WCS Differential (US$/bbl)	(11.98)	(15.00)	(15.00)	(15.00)	(15.00)
FX (CAD/USD)	0.79	0.78	0.78	0.78	0.78
WCS (CAD$/bbl)	62.01	57.69	57.69	57.69	57.69
Royalty Rate (%)	9%	9%	10%	10%	10%
Operating & Trans Costs ($/boe)	13.01	11.47	11.22	11.08	10.87
Debt/Cash Flow Ratio	0.4	0.3	0.4	0.3	0.3
Debt ($MM)	3	4	7	9	10
New Wells Drilled (37.7 net)	2.7	5.3	7.9	9.6	12.3

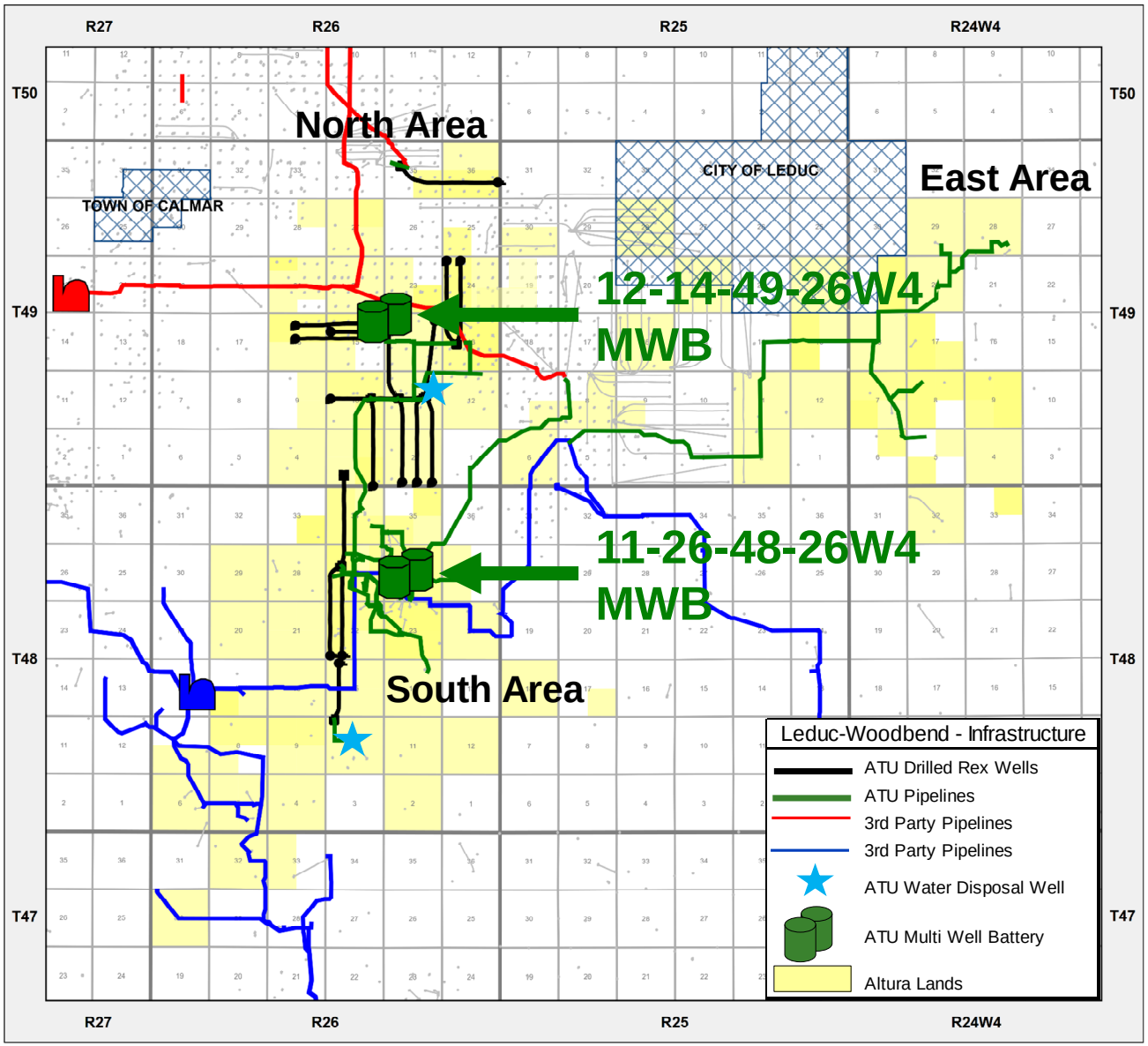
Leduc-Woodbend asset has the well inventory and drilling flexibility to self fund growth within cash flow and maintain a debt/cash flow ratio <0.5

Leduc-Woodbend development potential[(1)] derived by utilizing, among other assumptions, historical Altura production performance and pricing and cost assumptions included in the Key Assumptions table. Provided for illustration purposes only and assumptions are subject to change based on a variety of factors.

(i) denotes illustrative purposes

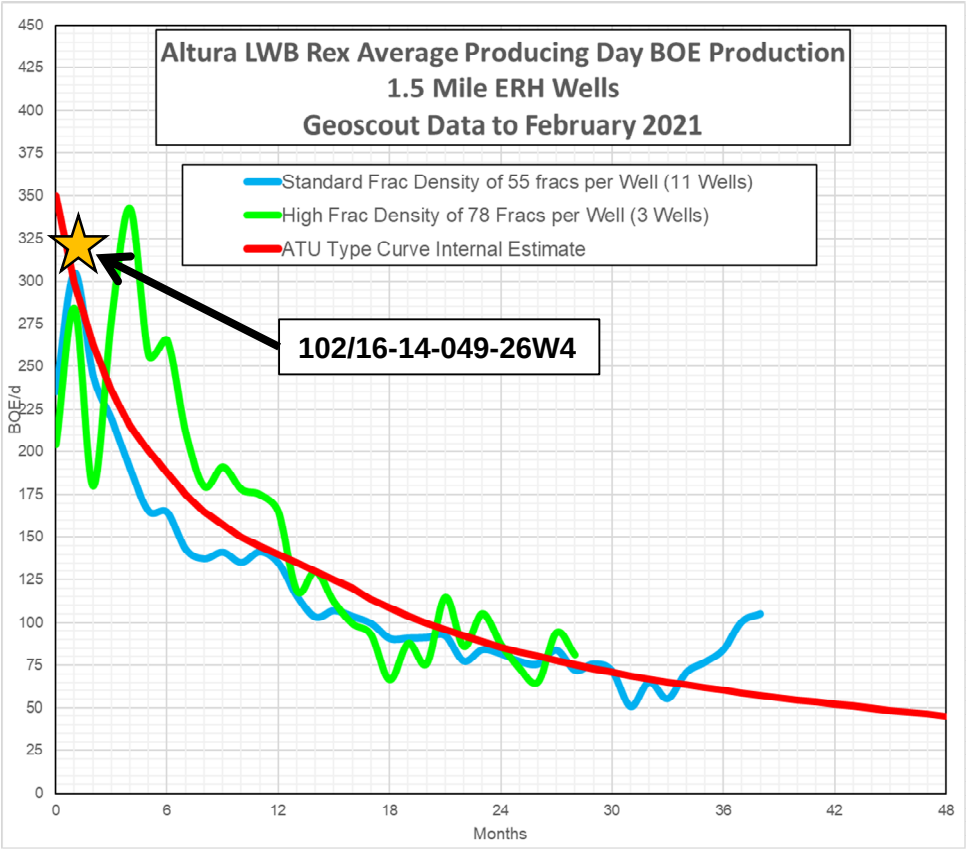
*Footnotes included at the end of presentation

Leduc-Woodbend Infrastructure



- Infrastructure in place to allow development of entire pool with minimal spending on pipelines and facilities
- All Rex wells have an emulsion gathering system and a separate casing gas gathering system to MWBs
- Gas is processed at 3rd party gas plants and clean oil is trucked to multiple sales terminals
- 12-14-49-26W4 MWB
  - Oil treating, booster compression, water injection
  - Capacity 2,500 bbl/d oil (7,500 Bbl/d total fluid), 4.5 MMcf/d gas
- 11-26-48-26W4 MWB
  - Oil treating, booster compression, water injection
  - Capacity 2,000 bbl/d oil (8,000 Bbl/d total fluid), 1.2 MMcf/d gas

Leduc-Woodbend Rex Economics



Future development will focus on drilling extended reach horizontal (ERH) 1.5+ mile long wells with high frac density of 78 fracs per well to maximize well productivity and capital efficiencies.

LWB Frac Economics 1.5-Mile Hz MSF w/ High Frac Density of 78 Fracs (2/3 Crown, 1/3 Freehold) (1) (2)			
WTI Pricing	**$US50/Bbl**	**$US60/Bbl**	**$US70/Bbl**
DCET Capital	$2.3 MM	$2.3 MM	$2.3 MM
1st Month IP Rate	350 Boe/d	350 Boe/d	350 Boe/d
1st Year Avg Rate	214 Boe/d	214 Boe/d	214 Boe/d
EUR	216 Mboe	226 Mboe	235 Mboe
NPV10BT	$0.8 MM	$2.0 MM	$3.1 MM
Payout (yrs)	**1.7**	**1.0**	**0.7**
IRR (%)	**46**	**117**	**236**
F&D	$10.55/Boe	$10.05/Boe	$9.68/Boe
Operating Cost*	$8.43/Boe	$8.43/Boe	$8.43/Boe
Operating Netback*	$22.58/Boe	$30.44/Boe	$37.98/Boe
Recycle Ratio	**2.1**	**3.0**	**3.9**
Liquids Weighting	67%	67%	67%

* First year averages

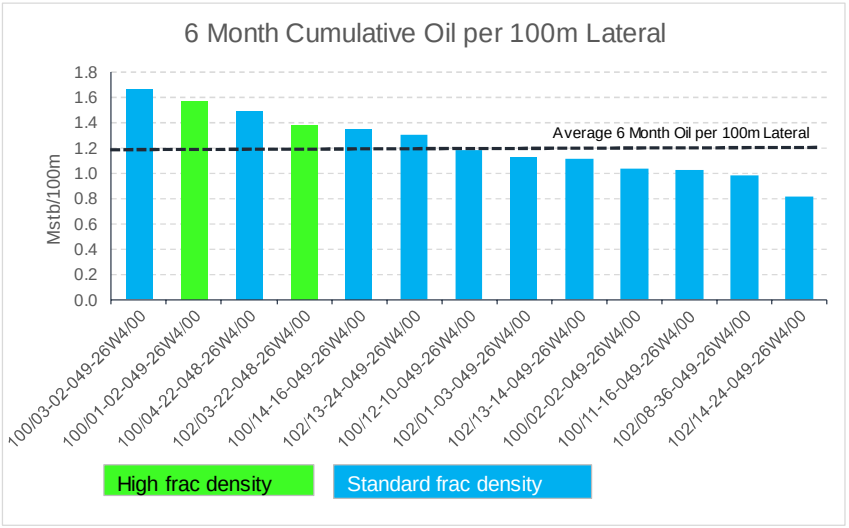
Refer to slide 22 for Price Forecast details

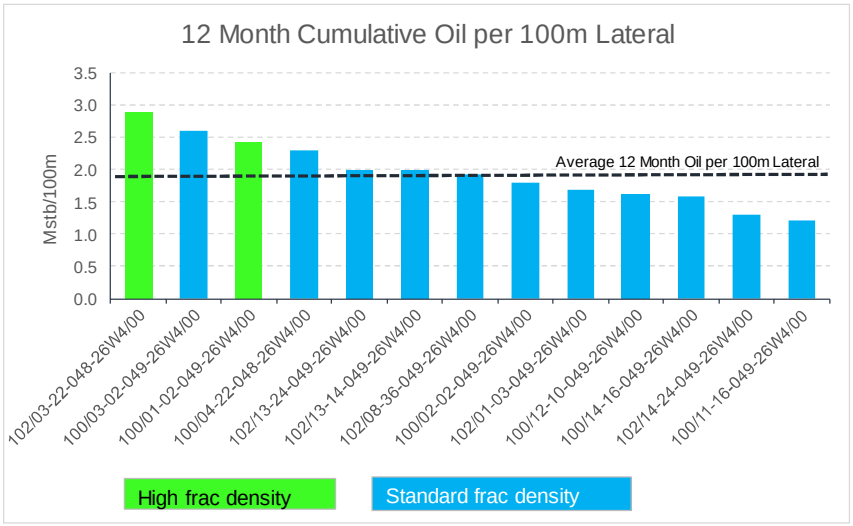
Well economics drive profitable, multi-year drilling programs

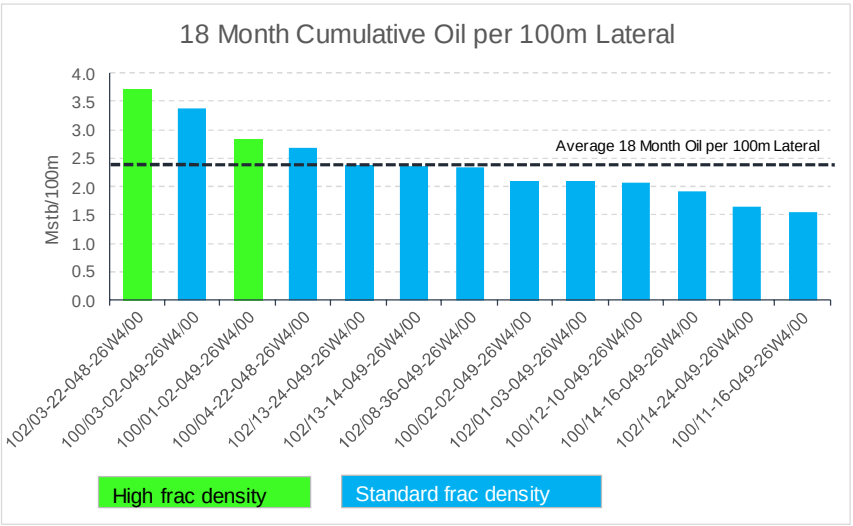
*Footnotes included at the end of presentation

Rex Completion Intensity

2016	2018	2019+
1 mile Hz, Standard Frac Density of 55 fracs per well, 20 tonnes per frac	1.5 mile Hz, Standard Frac Density of 55 fracs per well, 15 tonnes per frac	1.5-2 mile Hz, High Frac Density of 78 fracs per well, 12 tonnes per frac

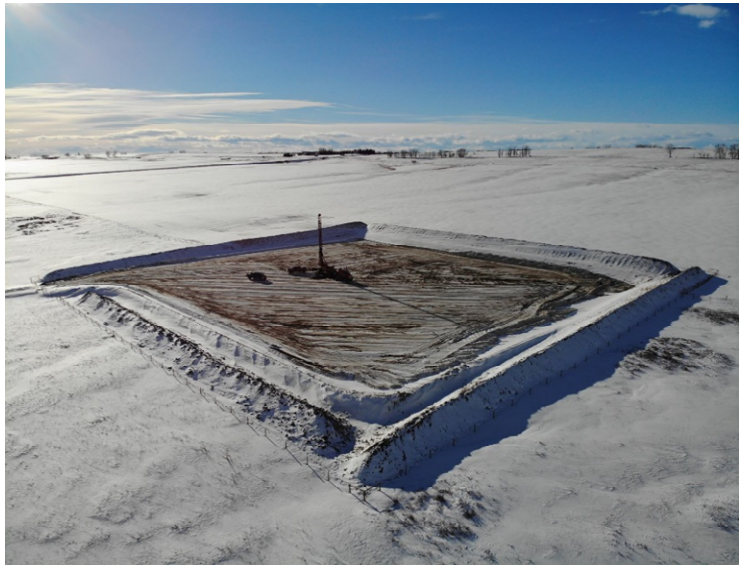




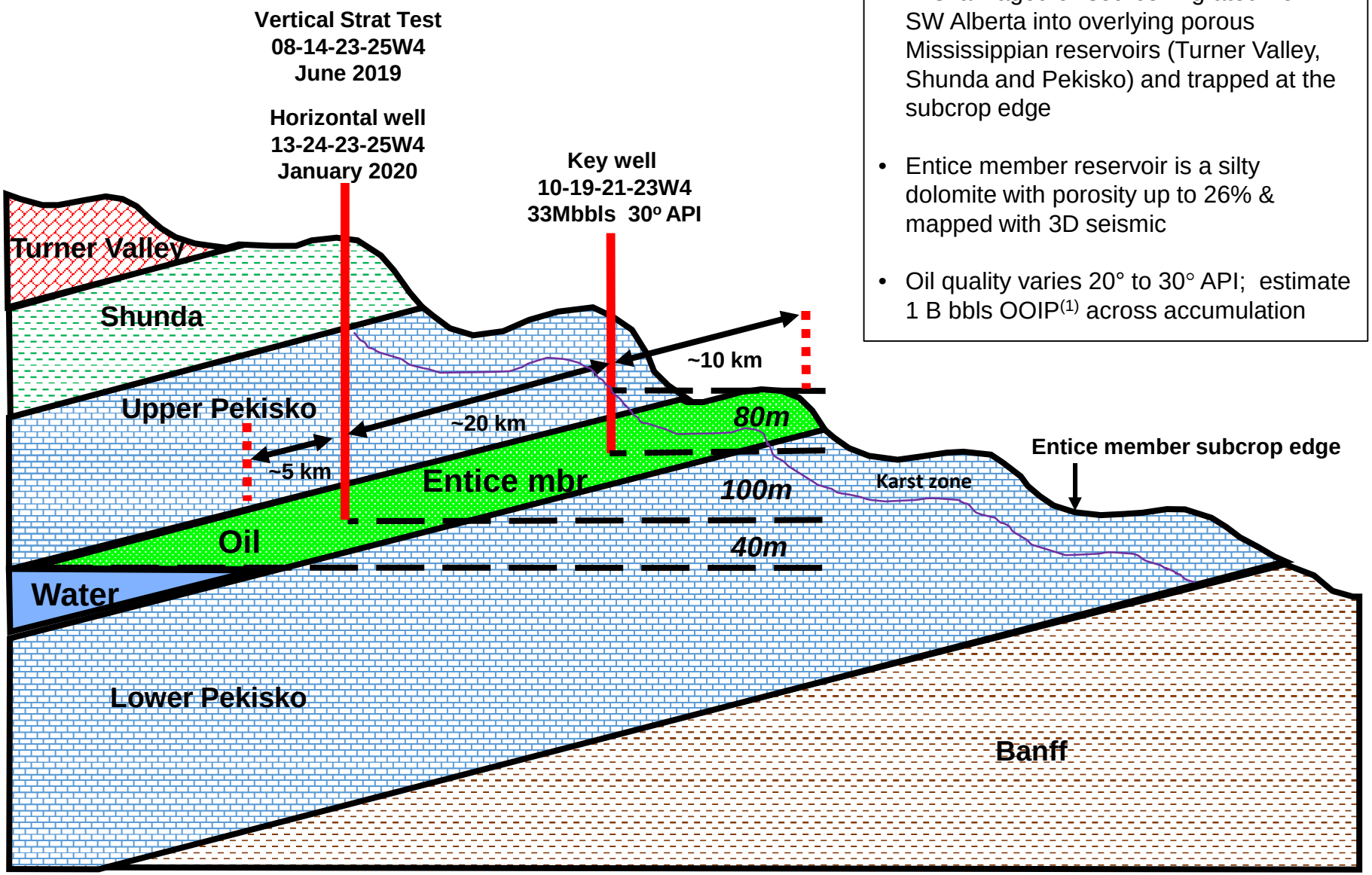


Entice

Concept	• Early stage, large resource, exploration play with year-round drilling access • Targeting the Entice member of Pekisko formation 1,600 – 1,750m TVD • Oil quality ranges from 20 – 30°API across the play • 89 gross (82 net) sections of land
Key Well	• 10-19-21-23W4 vertical well • Drilled & completed in 1973 • Produced 33Mbbls of 30° API oil
Altura Test Wells	• Drilled vertical stratigraphic test at 08-14-23-25W4 in June 2019 • Re-entered 08-14 and drilled follow up horizontal well to 13-24-23-25W4 in January 2020
Next Technical Steps	• Resume 13-24-23-25W4 production test • Re-enter vertical well that is 100 meters structurally up dip of 13-24 • Further to re-entry results, assess drilling a follow up horizontal well



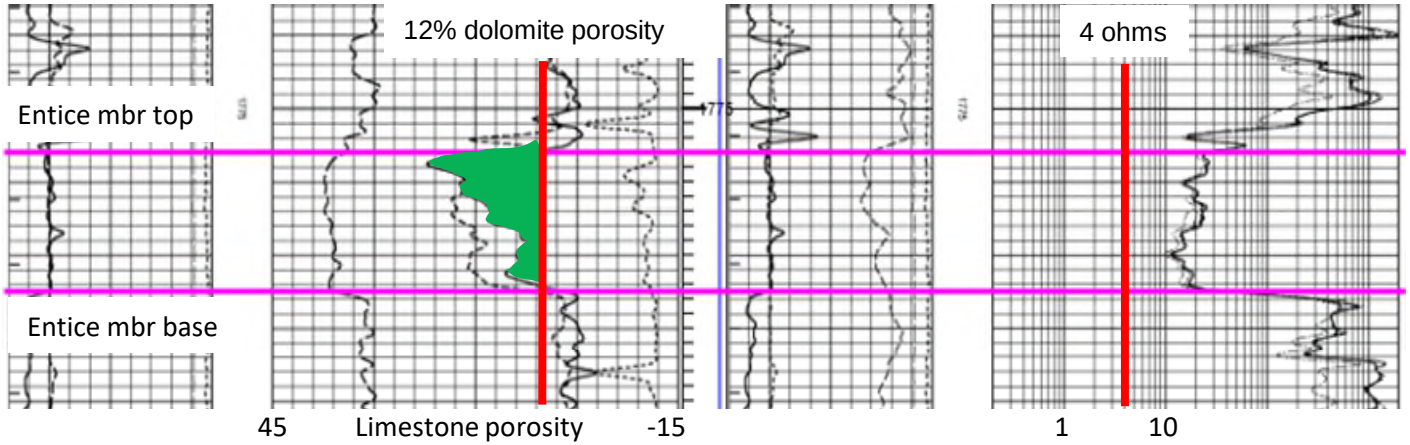
Entice Member Schematic



- Exshaw aged oil source migrated from SW Alberta into overlying porous Mississippian reservoirs (Turner Valley, Shunda and Pekisko) and trapped at the subcrop edge
- Entice member reservoir is a silty dolomite with porosity up to 26% & mapped with 3D seismic
- Oil quality varies 20° to 30° API; estimate 1 B bbls OOIP(1) across accumulation

Entice Member Log Results

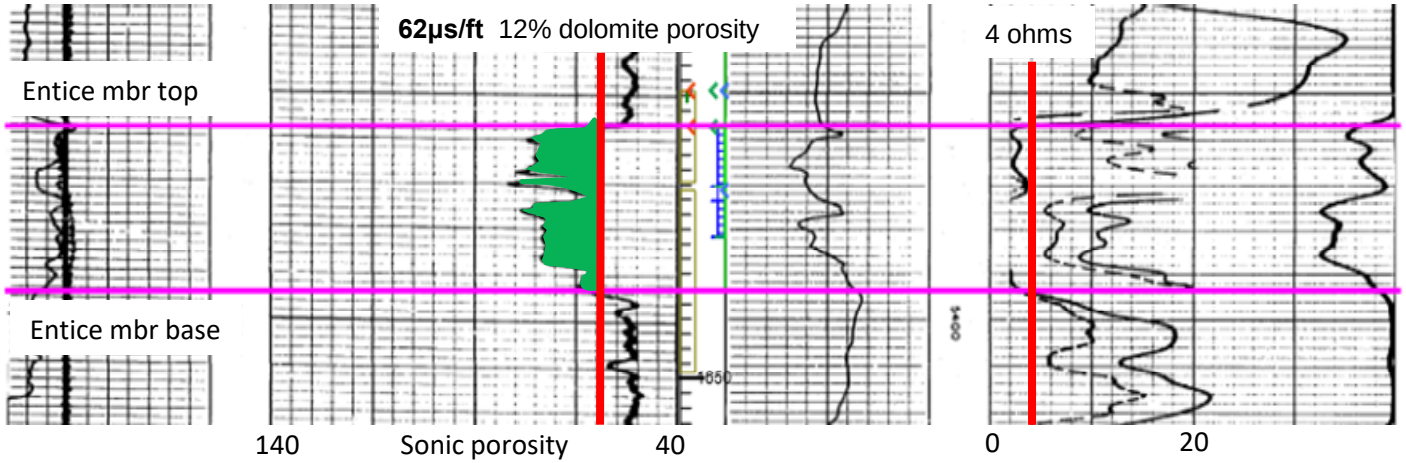
08-14-23-25W4 ATU stratigraphic test



Log results

- Gross 9.5 meter zone
- Geometric average porosity of 16.6%
- Permeability of 0.59 mD (1.11 mD arithmetic)
- This well is ~20 km west from 10-19-21-23W4

10-19-21-23W4 Analog well cum 33Mbbls 30º API



Completion results

- Perforated and acidized in 1973; produced for 4 months at an average rate of 26 bopd (no water). Shut in until 1983.
- Frac in 1983 with 10/20 sand and only placed 2.4t; produced for 3 months at an average rate of 16 bopd. Shut-in until 1996.
- On production from 1996 to 2014 w/ IP(3) 19 bopd and abandoned in 2017.

2021 Outlook

- Complete 1 (0.9 net) Leduc-Woodbend Rex hz well in Q1 2021
- Drill and complete 2 (1.8 net) Leduc-Woodbend Rex hz wells with high frac density of 78 fracs per well in H2 2021
- Resume Entice 13-24-23-25W4 production test, evaluate vertical well recompletion and assess drilling a follow-up horizontal well
- Target annual production of 1,150 boepd (31% increase over 2020)
- Maintain a strong balance sheet at < 1.0x debt/CF

Footnotes

Slide 3	(1)	Adjusted funds flow was $0.8 million for Q4 2020. See Non-GAAP Measures in the disclaimer section of this presentation
	(2)	Net debt was $3.9 million as at December 31, 2020. See Non-GAAP Measures in the disclaimer section of this presentation
	(3)	The Corporation's Liability Management Rating ("LMR") with the Alberta Energy Regulator ("AER") was 5.08 at April 3, 2021. The LMR reflects the results of a comparison of the Corporation's deemed assets to its deemed liabilities and is updated monthly. An LMR rating less than 1.0 would require the Corporation to pay a deposit to the AER
	(4)	The Corporation's undiscounted, un-escalated Asset Retirement Obligation (ARO) was $5.4 million ($1.7 million inflated at 2% and discounted at 10%) as at December 31, 2020
	(5)	See Disclaimers regarding Original Oil in Place. Net OOIP is the portion of Pool OOIP that is mapped on Altura lands
	(6)	See Drilling Locations in the disclaimer section of this presentation
	(7)	Market capitalization is based on Altura's April 21, 2021 closing share price of $0.155 per share
	(8)	Enterprise value equals market capitalization plus net debt
	(9)	Q4 2020 production consisted of 468 bbls/d of heavy oil, 48 bbls/d of NGLs and 2,402 Mcf/d of natural gas
Slide 4	(1)	Average production for 2020 was 880 boe/d and forecasted production for 2021 is expected to range between 1,100 to 1,150 boe per day as disclosed in Altura's January 29, 2021 press release
Slide 5	(1)	Adjusted funds flow per boe is a Non-GAAP measure. See Non-GAAP Measures in the disclaimer section of this presentation
Slide 7	(1)	See Disclaimers regarding Original Oil in Place. Net OOIP is the portion of Pool OOIP that is mapped on Altura lands
	(2)	See Drilling Locations in the disclaimer section of this presentation
Slides 8 and 14	(1)	See Disclaimers regarding Original Oil in Place. Net OOIP is the portion of Pool OOIP that is mapped on Altura lands
Slide 9	(1)	See Drilling Locations in the disclaimer section of this presentation
Slides 10	(1)	See FOFI disclosure information in the disclaimer section of this presentation
	(2)	See Non-GAAP Measures in the disclaimer section of this presentation
Slide 12	(1)	Assumes January 2021 on production date. See Appendix slide 21 for Oil Price Forecast details
	(2)	The type curve and 2P EUR has been developed by a qualified reserves evaluator (QRE) and in accordance with the Canadian Oil and Gas Evaluation (COGE) Handbook. The QRE is a company employee, a professional member of APEGA and has over 18 years of relevant industry and evaluation experience. Operating netback is a Non-GAAP measure. See Non-GAAP Measures in the disclaimer section of this presentation
	(3)	The analogous production information comes from public domain production data when available and company production data when the public domain data is not available
Slide 17	(1)	Altura's capital program for 2021 totals $6 million and includes drilling 2 (1.8 net) and completing 3 (2.7 net) wells as disclosed in Altura's January 29, 2021 press release
Slide 24	(1)	Operating netback, operating netback after realized gain on financial instruments and adjusted funds flow per boe are Non-GAAP measures. See Non-GAAP Measures in the disclaimer section of this presentation

Disclaimers

FORWARD-LOOKING STATEMENTS This presentation contains “forward-looking statements.” The use of any of the words "expect", "anticipate", "budget", "forecast", "continue", "estimate", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "strategy" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this presentation contains forward-looking information and statements pertaining to: 2021 drilling plans and capital expenditure guidance, development of Leduc-Woodbend, including (without limitation) the Leduc-Woodbend development potential from 2021 to 2025, estimated operational results, including relating to costs, expenses, production, revenue, rates of return, time to payout, debt and cash flow.

Statements relating to reserves and resources are also 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 is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resource.

Forward-looking statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ materially from those reflected in the statements. Forward-looking statements are based on the estimates and opinions of Altura’s management at the time the statements are made. Although Altura believes that the expectations reflected in these forward-looking statements are reasonable, such statements are subject to known or unknown risks and uncertainties that may cause actual results to differ materially from those anticipated.

Altura has no obligation to update these forward-looking statements should circumstances or management’s estimates or opinions change. Investors should be aware that Altura’s future performance is subject to a wide range of risk factors including:

- the continued performance of Altura’s oil and gas properties in a manner consistent with its past experiences;
- that Altura will continue to conduct its operations in a manner consistent with past operations;
- the return of industry conditions to pre-COVID-19 levels;
- unanticipated operating results or production declines;
- public health crises, such as the recent outbreak of COVID-19 and the related economic disruption that can result in volatility in financial markets, disruption to global supply chains, and the ability to directly and indirectly staff the Corporation’s day to day operations;
- volatility in market prices for crude oil, natural gas and other hydrocarbons;
- economic conditions in Canada, North America and internationally;
- industry conditions (including changes in laws and regulations);
- the results of exploration and development drilling by Altura;
- imprecision in reserve and resource estimates;
- unexpected change in the production and growth potential of Altura’s assets; and,
- Altura’s ability to access sufficient capital.

All of these factors are beyond Altura’s control and may have a material negative effect on Altura’s performance.

FOFI DISCLOSURE This presentation contains information that may be considered to be future-oriented financial information and (or) financial outlook information (collectively, “FOFI”) about Altura’s prospective results of operations and production, royalty rates, operating costs, transportation costs, net operating income and net debt, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs and the assumptions outlined in the Non-GAAP measures section below. FOFI contained in this presentation was approved by management as of the date of this presentation and was provided for the purpose of providing further information about Altura’s anticipated future business operations, and such information may not be appropriate for other purposes. Altura disclaims any intention or obligation to update or revise any FOFI contained in this presentation, whether as a result of new information, future events or otherwise, unless required pursuant to applicable law. Readers are cautioned that the FOFI contained in this presentation should not be used for purposes other than for which it is disclosed herein.

OIL AND GAS ADVISORY “Boe” means barrel of oil equivalent on the basis of 6 mcf of natural gas to 1 Bbl of oil. Boe's may be misleading, particularly if used in isolation. A Boe conversion ratio of 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. In addition, 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 on a 6:1 basis may be misleading as an indication of value. The estimated values of the future net reserves of the reserves disclosed in this presentation do not represent the market value of such reserves. The estimates of reserves and future net reserve for individual properties may not reflect the same confidence level as estimates of reserves and future net reserve for all properties due to the effects of aggregation.

Disclaimers Continued

NON-GAAP MEASURES This document contains the terms ”net operating income”, “adjusted funds flow”, “adjusted funds flow per boe”, “net debt”, “operating netback”, and “operating netback after realized gain on financial instruments” which do not have a standardized meaning prescribed by International Financial Reporting Standards (“IFRS” or, alternatively, “GAAP”) and therefore may not be comparable with the calculation of similar measures by other companies. Net operating income is calculated by revenue and subtracting royalties, operating costs and transportation costs. Altura considers net operating income to be a key measure of performance as it demonstrates the property’s ability to generate the necessary funds for sustaining capital and future growth through capital investment. Adjusted funds flow is calculated by taking net income or loss before taxes and adding back items, including transaction costs, and certain non-cash items including stock-based compensation; accretion expense on decommissioning obligations; depletion, depreciation and amortization; impairment; unrealized gain or loss on financial instruments; and gain or loss on dispositions. Altura considers adjusted funds flow to be a key measure of performance as it demonstrates the Corporation's ability to generate the necessary funds for sustaining capital, future growth through capital investment, and to repay debt. Management believes that such a measure provides a useful assessment of Altura’s business on a continuing basis by eliminating certain non-cash charges, transaction costs, if any. Altura calculates operating netback on a per boe basis as petroleum and natural gas sales less royalties, operating and transportation costs. Operating netback after realized gain on financial instruments is operating netback less realized gains on financial instruments. Management feels that operating netback is a key industry benchmark and a measure of performance for Altura that provides investors with information that is commonly used by other crude oil and natural gas producers. The measurement on a per boe basis assists management and investors with evaluating operating performance on a comparable basis. Management views net debt as a key industry benchmark and measure to assess the Corporation's financial position and liquidity. Net debt is calculated as current assets less current liabilities, excluding the fair value of financial instruments, less the current portion of lease liabilities and less the current portion of the decommissioning liability. Additional information relating to these non-GAAP measures, including the reconciliation between “adjusted funds flow” and “net income”, can be found in the Corporation's most recent management's discussion and analysis which is available on SEDAR at www.sedar.com.

WELL ECONOMICS The Corporation has presented certain well economics based on historic performance of wells drilled by the Corporation based on different commodity pricing sensitivities. Such well economics are not intended to provide an estimate of future performance of wells or an estimate of reserves or resources.

DRILLING LOCATIONS This presentation discloses drilling locations in three categories: (i) proved locations; (ii) probable locations; and (iii) potential drilling opportunities. Proved locations and probable locations, which are sometimes collectively referred to as "booked locations", are derived from the Corporation’s most recent independent reserves evaluation as of December 31, 2020 and account for drilling locations that have associated proved reserves or probable reserves, as applicable. Potential drilling opportunities are internal estimates based on the Corporation’s prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and Altura’s internal review. Potential drilling opportunities do not have attributed reserves or resources. The Corporation has, based on the December 31, 2020 reserve report and management’s current internal assessment, 24.6 net proved locations, 12.0 net probable locations and 67.0 net potential drilling opportunities. Potential drilling opportunities have specifically been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves data on prospective acreage and geologic formations. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, crude oil and natural gas prices, costs, actual drilling results and other factors. While certain of the potential drilling opportunities have been derisked by drilling existing wells in relative close proximity to such potential drilling opportunities, the majority of other potential drilling opportunities 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 reserves, resources or production.

ORIGINAL OIL IN PLACE (OOIP) For the purpose of this presentation, Original Oil in Place ("OOIP") means Discovered Petroleum Initially In Place ("DPIIP") as at December 31, 2020. DPIIP is derived by Altura’s internal Qualified Reserve Evaluators ("QRE") and prepared in accordance with National Instrument 51-101 and the Canadian Oil and Gas Evaluations Handbook ("COGEH"). DPIIP, as defined in COGEH, is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of DPIIP includes production, reserves and Resources Other Than Reserves (ROTR). The OOIP/DPIIP and potential recovery rate estimates are as at December 31, 2020 and are based on current recovery technologies and have been prepared by Altura’s internal QRE. There is significant uncertainty as to the ultimate recoverability and commercial viability of any of the resource associated with the OOIP/DPIIP estimates, and as such a recovery project cannot be defined for this volume of OOIP/DPIIP at this time.

Appendix

Reserves & Hedging

December 31, 2020 Reserves (1)						
Reserve Category	**Light Crude and Medium Crude Oil (Mbbl)**	**Heavy Crude Oil (Mbbl)**	**Conventional Natural Gas (MMcf)**	**Natural Gas Liquids (Mbbl)**	**Total (Mboe)**	**NPV BT10% (2) ($M)**
Proved Producing	164.5	562.8	3,439.0	100.3	1,400.8	10,604.1
Proved Non-Producing	11.4	83.5	252.7	7.3	144.4	1,391.5
Proved Undeveloped	-	2,559.0	8,034.1	233.0	4,131.1	13,565.6
Total Proved (1P)	176.0	3,205.4	11,725.8	340.6	5,676.3	25,561.2
Probable	67.3	2,439.2	12,491.8	362.8	4,951.3	31,887.2
Total Proved + Probable (2P)	**243.3**	**5,644.7**	**24,217.6**	**703.4**	**10,627.6**	**57,448.5**

(1) Evaluated by McDaniel & Associates Consultants ("McDaniel") as at December 31, 2020. Net present value of future net revenue does not represent the fair market value of the reserves.
(2) NPV BT10% values are based on the average of the published price forecasts for McDaniel, GLJ Petroleum Consultants Ltd., and Sproule Associates Ltd. at January 1, 2021.

Hedge Portfolio	Q2 2021	Q3 2021	Q4 2021	Jan 2022	Feb 2022
Oil					
Volumes hedged (Bbls/d)	200	200	200	200	125
Average WCS Fixed Price Swap (CAD$/Bbl)	$35.73	$36.70	$38.70	$51.00	$55.50
Natural Gas					
Volumes hedged (GJ/d)	1,000	1,668	1,000	1,000	750
Average AECO (5A) Fixed Price Swap (CAD$/GJ)	$2.46	$2.56	$2.55	$2.72	$2.87

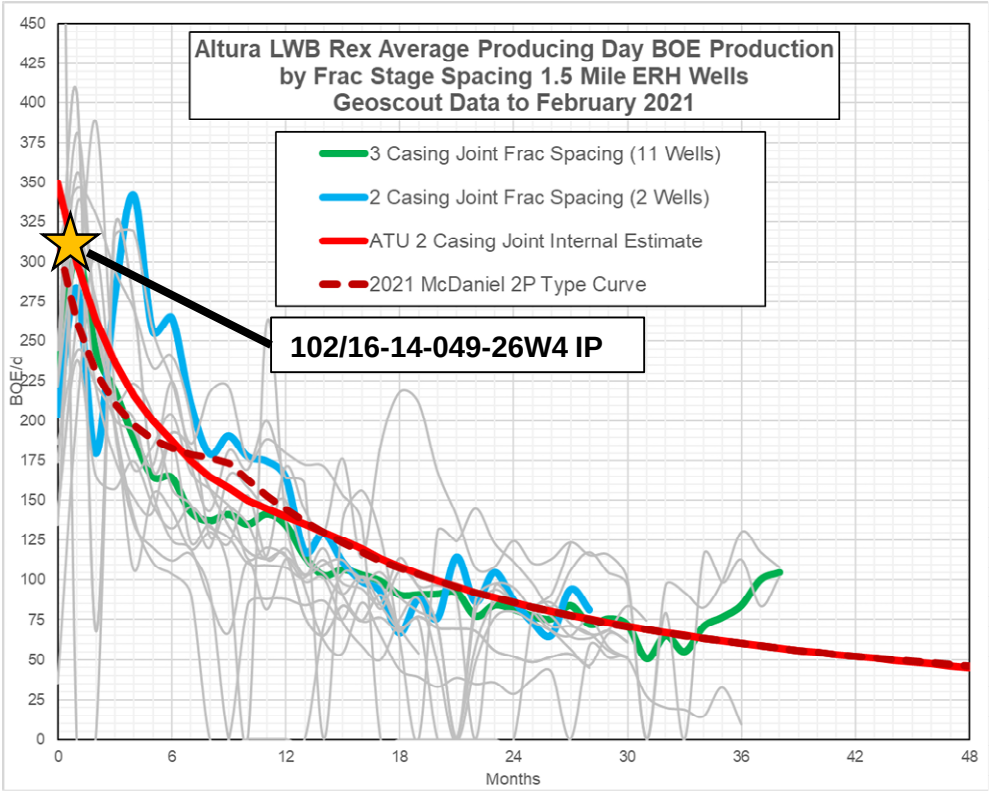
WCS Price Forecasts for Economics Slide 12

WCS US$30/Bbl	WTI US$/Bbl	WTI-WCS Differential US$/Bbl	WCS US$/Bbl	WCS CAD$/Bbl	F/X CAD/USD	Natural Gas CAD$/GJ
2020	50.00	15.00	35.00	44.87	0.78	2.56
2021	50.00	15.00	35.00	44.87	0.78	2.56
2022	50.00	15.00	35.00	44.87	0.78	2.56
2023	50.00	15.00	35.00	44.87	0.78	2.56
2024	50.00	15.00	35.00	44.87	0.78	2.56
>2025	50.00	15.00	35.00	44.87	0.78	2.56

WCS US$40/Bbl	WTI US$/Bbl	WTI-WCS Differential US$/Bbl	WCS US$/Bbl	WCS CAD$/Bbl	F/X CAD/USD	Natural Gas CAD$/GJ
2020	60.00	15.00	45.00	57.96	0.78	2.56
2021	60.00	15.00	45.00	57.96	0.78	2.56
2022	60.00	15.00	45.00	57.96	0.78	2.56
2023	60.00	15.00	45.00	57.96	0.78	2.56
2024	60.00	15.00	45.00	57.96	0.78	2.56
>2025	60.00	15.00	45.00	57.96	0.78	2.56

WCS US$50/Bbl	WTI US$/Bbl	WTI-WCS Differential US$/Bbl	WCS US$/Bbl	WCS CAD$/Bbl	F/X CAD/USD	Natural Gas CAD$/GJ
2020	70.00	15.00	55.00	70.51	0.78	2.56
2021	70.00	15.00	55.00	70.51	0.78	2.56
2022	70.00	15.00	55.00	70.51	0.78	2.56
2023	70.00	15.00	55.00	70.51	0.78	2.56
2024	70.00	15.00	55.00	70.51	0.78	2.56
>2025	70.00	15.00	55.00	70.51	0.78	2.56

Leduc-Woodbend Rex Economics



Future development will focus on drilling extended reach horizontal (ERH) 1.5+ mile long wells with 2 casing joint frac spacing to maximize well productivity and capital efficiencies.

LWB 2 Casing Joint Well Economics 1.5-Mile Hz MSF (2/3 Crown, 1/3 Freehold) (1) (2)			
WTI Pricing	**$US50/Bbl**	**$US60/Bbl**	**$US70/Bbl**
DCET Capital	$2.3 MM	$2.3 MM	$2.3 MM
1st Month IP Rate	350 Boe/d	350 Boe/d	350 Boe/d
1st Year Avg Rate	214 Boe/d	214 Boe/d	214 Boe/d
EUR	216 Mboe	226 Mboe	235 Mboe
NPV10BT	$0.8 MM	$2.0 MM	$3.1 MM
Payout (yrs)	**1.7**	**1.0**	**0.7**
IRR (%)	**46**	**117**	**236**
F&D	$10.55/Boe	$10.05/Boe	$9.68/Boe
Operating Cost*	$8.43/Boe	$8.43/Boe	$8.43/Boe
Operating Netback*	$22.58/Boe	$30.44/Boe	$37.98/Boe
Recycle Ratio	**2.1**	**3.0**	**3.9**
Liquids Weighting	67%	67%	67%

* First year averages

Refer to slide 22 for Price Forecast details

Well economics drive profitable, multi-year drilling programs

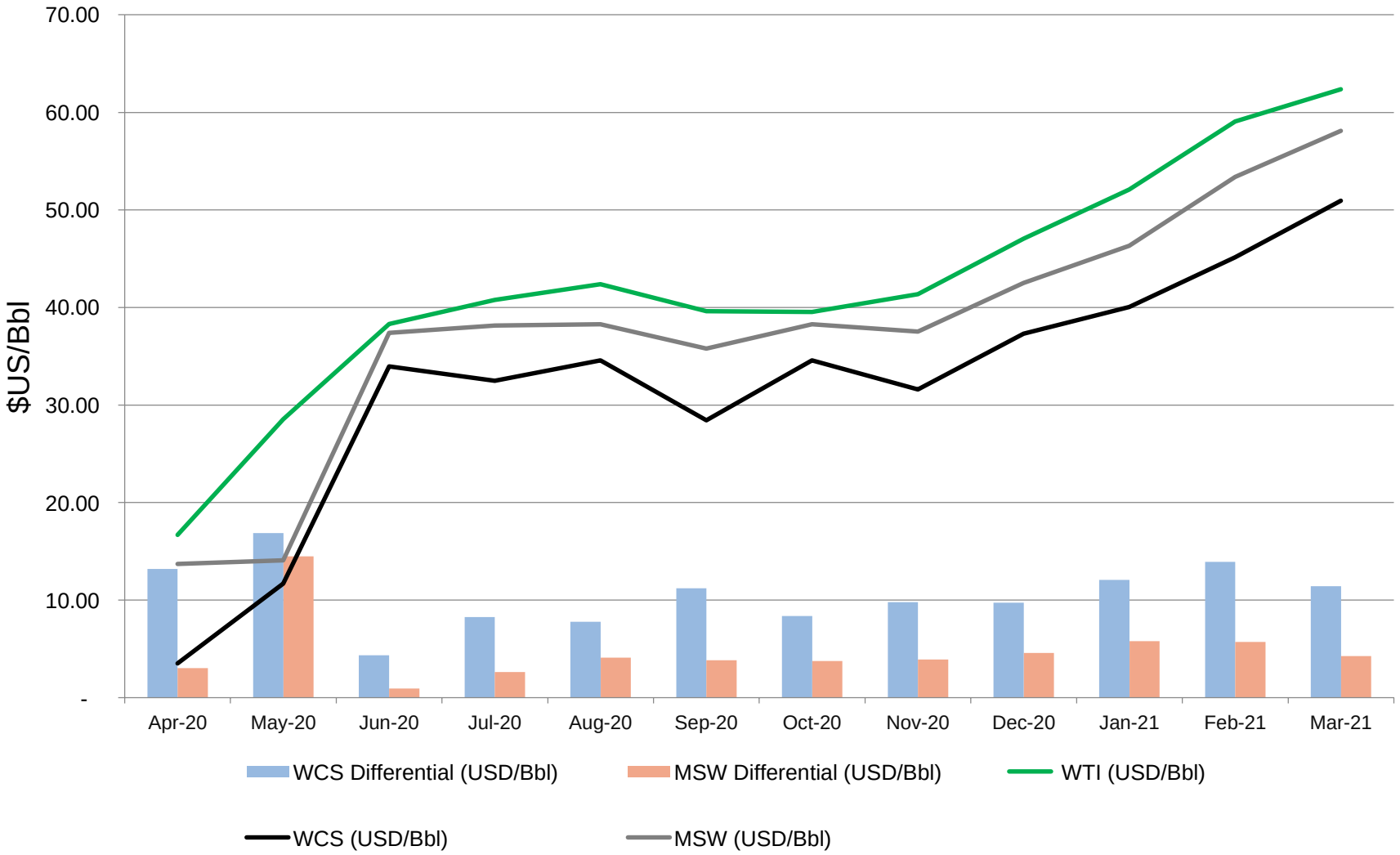
*Footnotes included at the end of presentation

Historical Summary

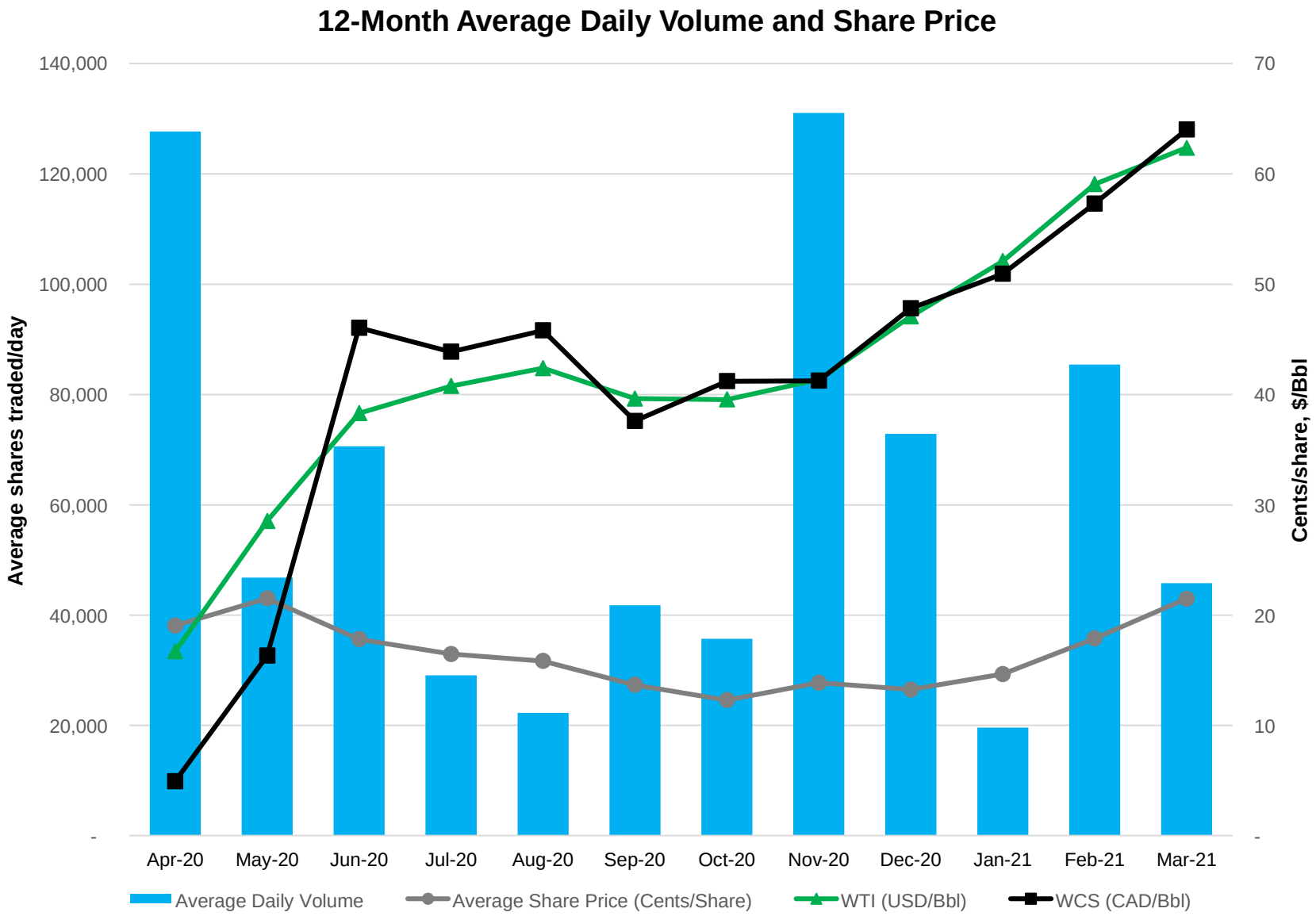
	Q4'19	Q1'20	Q2'20	Q3'20	Q4'20
Heavy crude oil (bbls/d)	881	667	213	512	468
Light crude & medium crude oil (bbls/d)	-	8	-	16	-
Natural gas (Mcf/d)	3,406	2,926	1,154	2,118	2,402
NGLs	113	87	30	38	48
Average Production Boe/d	1,561	1,250	435	919	919
Crude oil and NGL weighting	64%	61%	56%	62%	56%
$/Boe:					
PNG Revenue	$38.50	$24.46	$16.36	$29.87	31.56
Royalties	($4.43)	($1.96)	$0.28	($2.63)	($2.61)
Operating	($8.63)	($12.19)	($16.27)	($13.85)	($12.75)
Transportation	($2.45)	($2.49)	($2.46)	($2.51)	($1.93)
Operating Netback[(1)]	22.99	$7.82	($2.09)	$10.88	14.27
Realized gain on financial instruments	$0.53	$5.53	$16.60	$0.51	1.48
Operating Netback after realized gain on financial instruments[(1)]	$23.52	$13.35	$14.51	$11.39	$15.75
G&A	($2.52)	($3.50)	($7.98)	($5.71)	($4.66)
Interest Expense	($0.37)	($0.17)	($1.42)	($1.21)	($1.39)
Adjusted Funds Flow[(1)]	$20.63	$9.68	$5.11	$4.47	$9.70

*Footnotes included at the end of presentation

Historical Canadian Oil Differentials



Trading History



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