Creating Sustainable Value

April 2022 – Enercom Dallas

See Disclaimers and Forward-Looking Statements attached

tamarack valley ENERGY ltd.

Disclaimers

Forward Looking Statements: Certain information included in this presentation constitutes forward-looking information under applicable securities legislation. Forward-looking information typically contains statements with words such as “anticipate”, “believe”, “expect”, “plan”, “intend”, “estimate”, “propose”, “project” or similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information in this presentation may include, but is not limited to, statements about: our corporate strategy, objectives, strength, focus and updated five year plan and the anticipated benefits thereof; the proposed acquisition of all of the issued and outstanding common shares of Crestwynd Exploration Ltd. (“Crestwynd”) pursuant to which the Company will further establish its position as a leading operator in the Clearwater area (the “Acquisition”), including the terms, timing and anticipated benefits and strategic rationale of such Acquisition; the increased capacity under the Company’s credit facilities, the extension of the revolving facility and the transition to a sustainability linked lending facility and the terms thereof, including sustainability performance targets; future intentions with respect to return of capital including dividends and share buybacks, including annual shareholder return potential; net debt reduction and debt targets; Tamarack's intention to return free funds flow to shareholders; the dividend policy; the granting of any special dividends or any share buybacks or other supplements to the base dividend; statements regarding plans or expectations for the declaration of future dividends and the amount thereof; Tamarack’s commitment to ESG principles and Indigenous relationships, including as disclosed in the Company’s 2021 Sustainability Report; Tamarack’s liquidity and financial position, the factors contributing thereto, the impact thereof and plans relating thereto; and Tamarack’s 2022 capital budget and guidance and capital program, including the timing and level capital expenditures; future production levels, including annual average production; oil and liquids weighting and changes thereto; development opportunities; drilling locations; economics and payouts of our wells; corporate decline rate and improvements thereto with greater exposure to assets under waterflood; application of EOR; hedging positions and targets; future waterflood potential, plans, outlook, estimates and forecasts; future land and seismic investments; additional consolidation opportunities; and future commodity prices including sustaining breakeven prices and exchange rates. Statements relating to “reserves” 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. Without limitation of the foregoing, future dividend payments, if any, and the level thereof, is uncertain, as the Company's dividend policy and the funds available for the payment of dividends from time to time is dependent upon, among other things, commodity prices, free funds flow financial requirements for the Company's operations and the execution of its growth strategy, fluctuations in working capital and the timing and amount of capital expenditures, debt service requirements and other factors beyond the Company's control. Further, the ability of Tamarack to pay dividends will be subject to applicable laws (including the satisfaction of the solvency test contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness, including its credit facility.

Forward-looking information is based on a number of factors and assumptions concerning Tamarack, Crestwynd and the assets to be acquired pursuant to the Acquisition which have been used to develop such information, but which may prove to be incorrect. In addition to other factors and assumptions which may be identified in this presentation, assumptions have been made regarding and are implicit in, among other things, satisfaction or waiver of the closing conditions to the Acquisition, receipt of required regulatory approvals for the completion of the Acquisition (including approval of the Toronto Stock Exchange), the success of future drilling, development and completion activities, the performance of existing wells, the performance of new wells, the performance of EOR projects, the availability and performance of facilities and pipelines, the geological characteristics of Tamarack’s properties, including the assets to be acquired pursuant to the Acquisition, the successful application of drilling, completion and seismic technology, prevailing weather and break-up conditions and access to our drilling locations, commodity prices, price volatility, price differentials and the actual prices received for the Company’s products, royalty regimes and exchange rates, the application of regulatory and licensing requirements, the availability of capital, labour and services, our ability to complete planned capital expenditures within budgeted cost estimates, the ability to market our and gas successfully, our ability to integrate assets and employees acquired through acquisitions, the creditworthiness of industry partners and our ability to acquire additional assets. Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions which have been used. Although Tamarack believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because Tamarack can give no assurance that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), incorrect assessment of the value of acquisitions, failure to realize the benefits of acquisitions, constraint in the availability of services, commodity price and exchange rate fluctuations, changes in legislation (including but not limited to tax laws, royalty regimes and environmental legislation), adverse weather or break-up conditions and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures. Production forecasts are directly impacted by commodity prices and the actual timing of our capital expenditures. Actual results may vary materially from forecasts due to changes in interest rates, oil differentials, exchange rates and the timing of expenditures and production additions. In addition, the Company cautions that current global uncertainty with respect to the spread of the COVID-19 virus and its effect on the broader global economy may have a significant negative effect on the Company. While the precise impact of the COVID-19 virus on the Company remains unknown, rapid spread of the COVID-19 virus and variants may continue to have a material adverse effect on global economic activity, and may continue to result in volatility and disruption to global supply chains, operations, mobility of people and the financial markets, which could affect interest rates, credit ratings, credit risk, inflation, business, financial conditions, results of operations and other factors relevant to the Company. These and other risks are set out in more detail in Tamarack’s annual information form for the year ended December 31, 2020 (the “AIF”) and Tamarack’s management’s discussion and analysis for the period ended September 30, 2021 (the “MD&A”) . The AIF and MD&A can be accessed on Tamarack’s website at www.tamarackvalley.ca or under Tamarack’s profile on www.sedar.com. Forward-looking information is 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 anticipated by the proposed management and described in the forward-looking information. The forward-looking information contained in this presentation is made as of the date hereof and the proposed management undertakes no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, unless required by applicable securities laws. The forward-looking information contained in this presentation is expressly qualified by this cautionary statement.

Disclaimers *(Oil and Gas Advisories)*

FOFI Disclosure: This presentation contains future-oriented financial information and financial outlook information (collectively, “FOFI”) about Tamarack’s updated five year plan, including generating sustainable long-term growth in free funds flow, dividends and share buybacks, prospective results of operations and production, debt, net debt, debt targets, cash flow, adjusted funds flow, free funds flow breakeven, half-cycle returns, long-term free funds flow growth, balance sheet strength, cash costs, ARO, netbacks, corporate netbacks, operating netbacks, operating costs, corporate decline rate, tax pools, capital structure and components thereof, including pro forma the Acquisition and the increased capacity under the Company’s credit facilities, 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-IFRS 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 Tamarack’s anticipated future business operations. Tamarack 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.

Reserves Disclosure: All reserve references in this presentation are to gross reserves as at the effective date of the applicable evaluation. Gross reserves are Tamarack’s total working interest reserves before the deduction of any royalties and including any royalty interests of Tamarack. The recovery and reserve estimates of Tamarack’s 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. The reserve estimates contained herein were derived from (i) a reserves assessment and evaluation prepared by GLJ Ltd., a qualified independent reserves evaluator, dated February 8 ,2021 with an effective date of December 31, 2020; (ii) in the case of the assets acquired pursuant to the acquisitions completed in March 2021, an internal estimate prepared by the Company’s internal Qualified Reserve Evaluators, with an effective date of March 1, 2021; (iii) in the case of the assets acquired pursuant to the acquisition completed on June 1, 2021, an internal estimate prepared on April 7, 2021 by the Company’s internal Qualified Reserve Evaluators, with an effective date of June 1, 2021; (iv) in the case of the Clearwater assets acquired on August 31, 2021, an internal estimate prepared by the Company’s internal Qualified Reserve Evaluators, with an effective date of June 1, 2021; and (v) in the case of the assets to be acquired pursuant to the Acquisition, an internal estimate prepared on November 30, 2021 by the Company’s internal Qualified Reserve Evaluators, with an effective date of February 1, 2022, in each case prepared in accordance with National Instrument 51-101 (“NI 51-101”) and the most recent publication of the Canadian Oil and Gas Evaluations Handbook (the “COGE Handbook”). It should not be assumed that the present worth of estimated future cash flow presented herein represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Tamarack’s 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. References in this presentation to peak rates, IRR, initial 30 day production rates (IP30), initial 90 day production rates (IP90) and other short-term production rates 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. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production of Tamarack. Analogous Information: In this presentation, the Company has provided certain information on the prospectivity and the production rate of wells on properties adjacent to the Company's/Crestwynd's acreage which is "analogous information" as defined by applicable securities laws. 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 the COGE Handbook. Regardless, estimates by engineering and geotechnical practitioners may vary and the differences may be significant. The Company believes that the provision of this analogous information is relevant to the Company's activities and forecasting, given its property ownership in the area (including as a result of the Acquisition); however, readers are cautioned that there is no certainty that the forecasts provided herein based on analogous information will be accurate. Type Curves: Certain type curves disclosure presented herein represents estimates of the production decline and ultimate volumes expected to be recovered from wells over the life of the well. 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. BOE Disclosure: The term barrels of oil equivalent (“BOE”) may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel of natural gas to barrels of oil equivalence is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All BOE conversions in the report are derived from converting gas to oil in the ratio mix of six thousand cubic feet of gas to one barrel of oil. OOIP Disclosure: The term original-oil-in-place (“OOIP”) is equivalent to total petroleum initially-in-place (“TPIIP”). TPIIP, as defined in the COGE Handbook, is that quantity of petroleum that is estimated to exist in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered. A portion of the TPIIP is considered undiscovered and there is no certainty that any portion of such undiscovered resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of such undiscovered resources. With respect to the portion of the TPIIP that is considered discovered resources, there is no certainty that it will be commercially viable to produce any portion of such discovered resources. A significant portion of the estimated volumes of TPIIP will never be recovered.

bbls	barrels	WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
bbls/d	barrels per day	AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada’s Alberta System
boe/d	barrels of oil equivalent per day	IFRS	International Financial Reporting Standards as issued by the International Accounting Standards Board
GJ	gigajoule	ROR	rate of return

mmcf/d	million cubic feet per day	P3	proved + probable + possible reserves
BOPD	barrels of oil per day	ERH	extended reach horizontal
NAV	net asset value	EUR	estimated ultimate recovery
TTM	trailing twelve months	FX	foreign exchange
EOR	Enhanced Oil Recovery	ESG	Environmental, Social and Governance

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Non-IFRS Measures: Certain financial measures referred to in this presentation, such as net debt, adjusted funds flow, free funds flow, free funds flow breakeven, field level free funds flow, year-end net debt to Q4 annualized adjusted funds flow, market capitalization, enterprise value and capital efficiency are not prescribed by IFRS. Tamarack uses these measures to help evaluate its financial, operating performance, and liquidity and leverage. These non-IFRS financial measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers. Net debt is calculated as long-term debt plus working capital surplus or deficit adjusted for risk management contracts. 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; unrealized gain or loss on foreign exchange; unrealized gain or loss on cross-currency swap; and gain or loss on dispositions. Free funds flow (formerly referred to as free adjusted funds flow) is calculated as adjusted funds flow less capital expenditures, excluding acquisitions and dispositions. Free funds flow breakeven (formerly referred to as free adjusted funds flow breakeven) is determined by calculating the minimum WTI price in US/bbl required to generate free funds flow equal to zero sustaining current production levels and all other variables held constant. Field level free funds flow is calculated as free funds flow before the effect of interest and general & administrative expenses. Debt adjusted free funds flow yield is calculated as free funds flow, adjusted for growth (to add back capital in excess of maintenance and ARO capital and to remove the adjusted funds flow associated with growth volumes), plus finance costs, the sum of which is divided by enterprise value. Year-end net debt to Q4 annualized adjusted funds flow is calculated as net debt divided by the annualized adjusted funds flow for the most recently completed quarter. Market capitalization is calculated as shares outstanding multiplied by the closing market price of the shares on the day referenced. Enterprise value is calculated as market capitalization less net debt. Capital efficiency is calculated as capital expenditures for a project or period divided by the incremental production attributable to the expenditures.

This presentation contains metrics commonly used in the oil and natural gas industry, such as operating netbacks (calculated on a per unit basis as oil, gas and natural gas liquids revenues less royalties, hedging gains (losses) and operating costs), operating field netback or OFN (total petroleum and natural gas sales, less royalties and net production and transportation expenses) NPV-10 (meaning the net present value (net of capex) of net income discounted at 10%), RLI (calculated by dividing reserves volumes by estimated production), EUR (meaning estimated ultimate recovery, an approximation of the quantity of oil or gas that is potentially recoverable or has already been recovered from a reserve or well), internal rate of return ("IRR") (a rate of return measure used to compare the profitability of an investment and represents the discount rate at which the net present value of costs equals the net present value of the benefits. The higher a project's IRR, the more desirable the project), adjusted funds flow (determined as gross oil, natural gas and natural gas liquids revenues including realized gains on commodity risk management contracts, less the following: royalties, operating costs, transportation costs, general and administrative costs and interest expense), free funds flow (calculated by subtracting adjusted funds flow in a period by the capital expenditures spent during that same period) and recycle ratio (measured by dividing the operating netback for the applicable period by finding and development cost per boe for the year, which is intended to compare netback from existing reserves to the cost of finding new reserves and may not accurately indicate the investment success unless the replacement reserves are of equivalent quality as the produced reserves), finding and development costs (calculated as the sum of field capital plus the change in future development capital (“FDC”) for the period divided by the change in reserves that are characterized as development for the period) and finding, development and acquisition costs (calculated as the sum of field capital plus acquisition capital plus the change in FDC for the period divided by the change in total reserves, other than from production, for the period). These terms have been calculated by management and do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare Tamarack’s operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this presentation, should not be relied upon for investment or other purposes.

Drilling Locations: This presentation discloses drilling locations two categories: (i) booked locations; and (ii) un-booked locations. Booked locations are proved and probable locations derived from an internal evaluation using standard practices as prescribed in the most recent publication of the COGE Handbook and account for drilling locations that have associated proved and/or probable reserves, as applicable. Un-booked locations are internal estimates and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Un-booked locations do not have attributed reserves or resources. Of the approximately 1,337 (1,245.7 net) drilling locations identified herein, including in respect of the Acquisition, 308 (290.2 net) are proved locations, 236 (219.8 net) are probable locations and 793 (735.7 net) are unbooked locations. Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

US Registration: This presentation is not 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 be any sale of the securities in any state in which such offer, solicitation or sale would be unlawful.

Corporate Snapshot (TSX: TVE)

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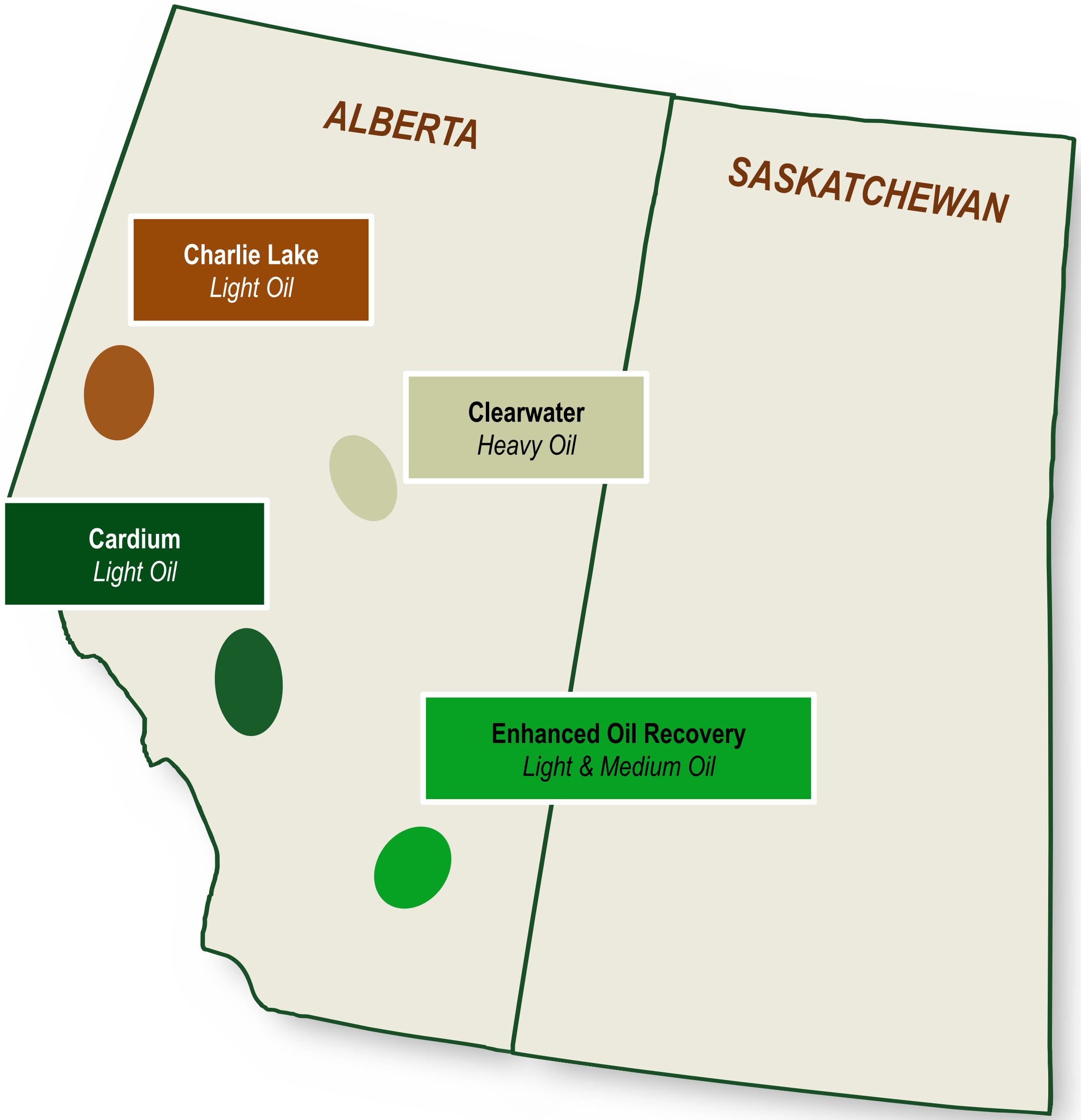
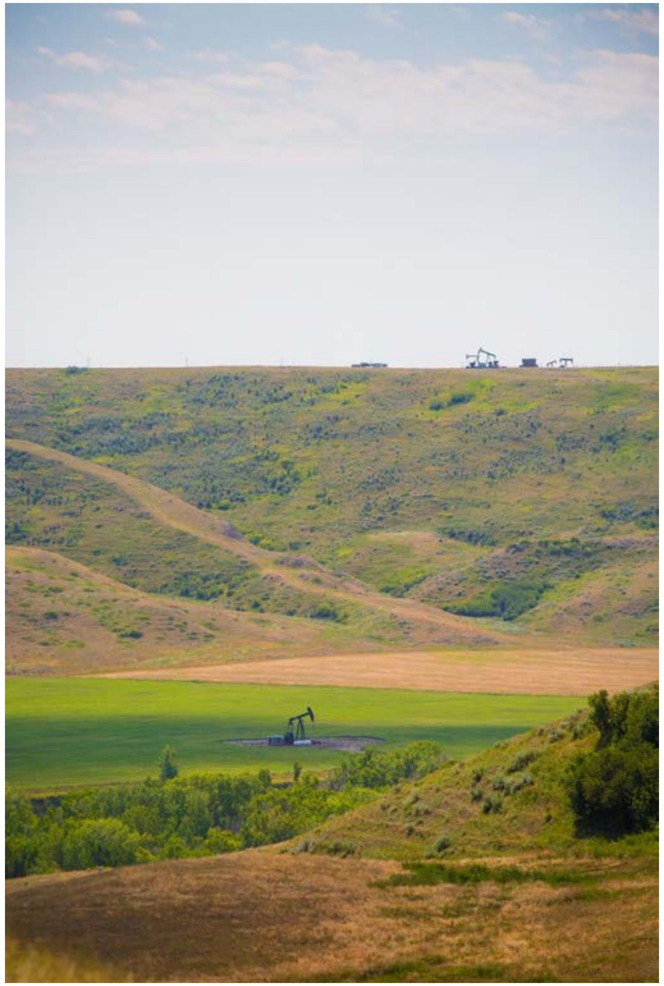
Corporate/Market Summary	Tamarack
Market Capitalization ($MM)	$2,177
Net Debt[(1),(2)] ($MM)	$563
Enterprise Value[(1)] ($MM)	$2,805
Tax Pools[(3)] ($MM)	$1,004

2022 Capital Budget and Guidance[(4)]	2022 Full Year
Average Production[(5)] (boe/d)	45,000 – 46,000
Capital Expenditures ($MM)	$250 – $270
Royalties	18% – 20%
Transportation ($/boe)	$2.00 – $2.10
Operating Costs ($/boe)	$8.50 – $8.70
G&A ($/boe)	$1.30 – $1.35
Sustaining FFF Breakeven[(1)] (US$/bbl WTI)	~$35.00



Q4 & Year End 2021 Highlights



Strategic Acquisitions

- *Closed $0.7 billion in acquisitions across 2021*
- *Added >1,000 quality locations, including Clearwater & Charlie Lake plays*

Financial Flexibility

- *Increased credit facilities to $600 million and transitioned to an SLL(2)*
- *Delivered 0.9x debt to Q4 annualized adjusted funds flow(1) at YE2021*

Optimized Production

- *Q4/21 average production of 40,384 boe/d(3) (69% liquids)*
- *2021 full year average production of 34,562 boe/d(4) (69% liquids)*

Free Funds Flow(1)

- *Generated record free funds flow(1) of $82.4 million in Q4*
- *Record FFF(1) growth to $149 million for full year 2021*

Capital Execution

- *Invested $191.2 million in E&D capital to drill 106 (101.8 net) wells in 2021*

Tamarack delivered on commitments through the completion of transformational strategic acquisitions, effective operational and capital execution and exceptional financial discipline

Tamarack Strategic Principles – Original

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Sustainable Returns Focused Strategy with Repeatable and Predictable Long-Life Resource Plays in the WCSB

Strategic Principles	Tactical Execution
Low Leverage & Balance Sheet Strength	**BALANCE SHEET STRENGTH AND RISK MANAGEMENT** • <0.7x 2022 YE net debt to Q4 annualized adjusted funds flow at US$70 WTI budget pricing[1] • Consistent hedging policy to manage exposure to commodity price volatility
Inventory Resiliency & Decline Rate	**BALANCED MULTI-PLAY PORTFOLIO WITH LEADING ECONOMIC DRILLING INVENTORY** • Diverse multi-play asset portfolio enables flexibility • Added >1,000 locations through a successful acquisition strategy over the past year
Free Funds Flow[1] Generation	**LOW FREE FUNDS FLOW BREAKEVEN[1] AND DECLINE RATE DRIVE STABLE FFF[1]** • Attractive corporate decline rate supported by waterfloods and highly sustainable oil production reduce Tamarack's free funds flow breakeven[1] to ~US$35/bbl WTI • Economic assets and inventory runway support free funds flow[1] growth
Prudent Approach to Return of Capital and Strategic M&A	**LOW LEVERAGE & STABLE FFF[1] GENERATION SUPPORT RETURN OF CAPITAL** • Excess free funds flow[1] and decreased leverage enable return of capital optionality • Disciplined deployment of capital to strategic M&A aligned with free funds flow[1] accretion • Base dividend declarations YTD with outlook for an enhanced dividend and/or NCIB mid-2022
Strong Commitment to ESG	**FOCUS ON ENVIRONMENT, INDIGENOUS PARTNERSHIPS, AND ETHICAL GOVERNANCE** • 39% reduction target in Scope 1 and 2 emissions intensity by 2025 (over 2020 baseline) • ARO spend exceeds annual voluntary targets set by the Alberta Energy Regulator • Commitment to continued indigenous partnerships and workforce participation (6% by 2025)

Capital Allocation Optionality Delivers Sustainability

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Portfolio that can deliver near-term and long-term free funds flow[(1)]

Waterflood Management	Sustaining Capital Modest Growth	Economic Growth
Low Decline, Stable Production Base	*Highly Economic Inventory that Sustains Meaningful Production While Generating Significant Free Funds Flow[(1)]*	*Highly Economic Production Growth*
Veteran Viking Light Oil *Eyehill Sparky Medium Oil* *Slave Point and Penny Light Oil*	*Charlie Lake Light Oil Wells* *Viking Primary Oil Wells* *Cardium/Falher Wells*	*Nipisi Clearwater Oil Wells* *Jarvie Clearwater Oil Wells*
~25%	*~40%*	*~35%*

Capital Allocation Across a Portfolio of High Quality, Long-Life Oil Assets that Delivers Production and Free Funds Flow[(1)] per Share Growth

Percent of 2022 Capital Program

Positioned for Strong Financial Flexibility

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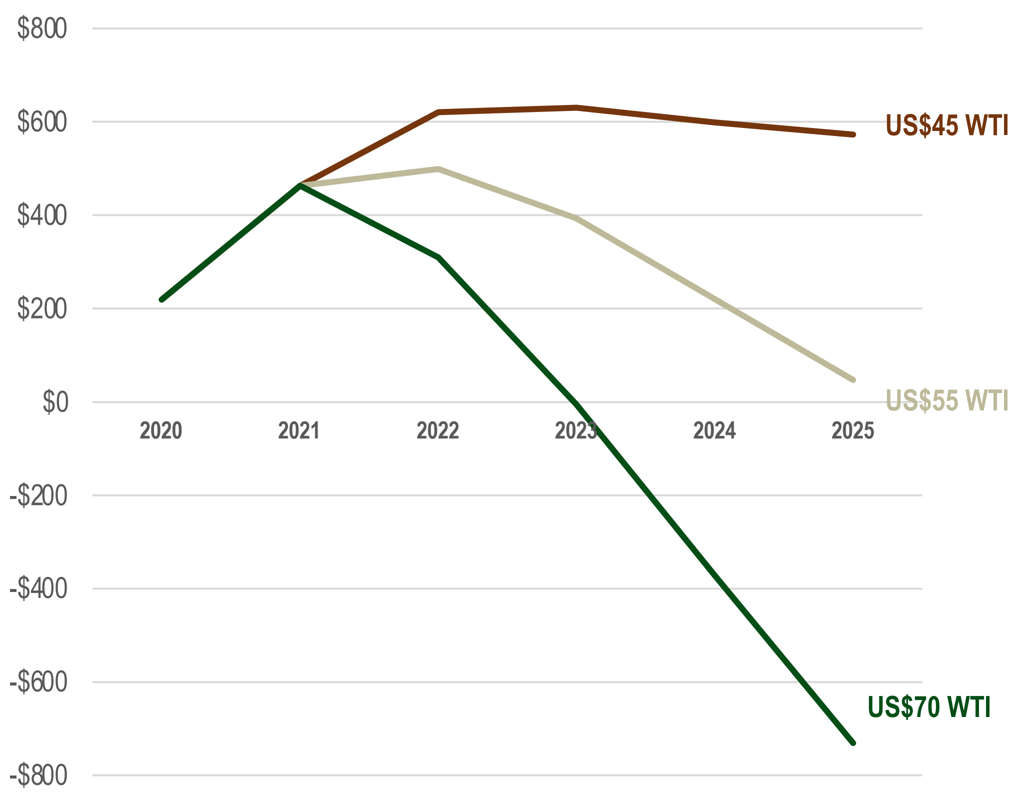
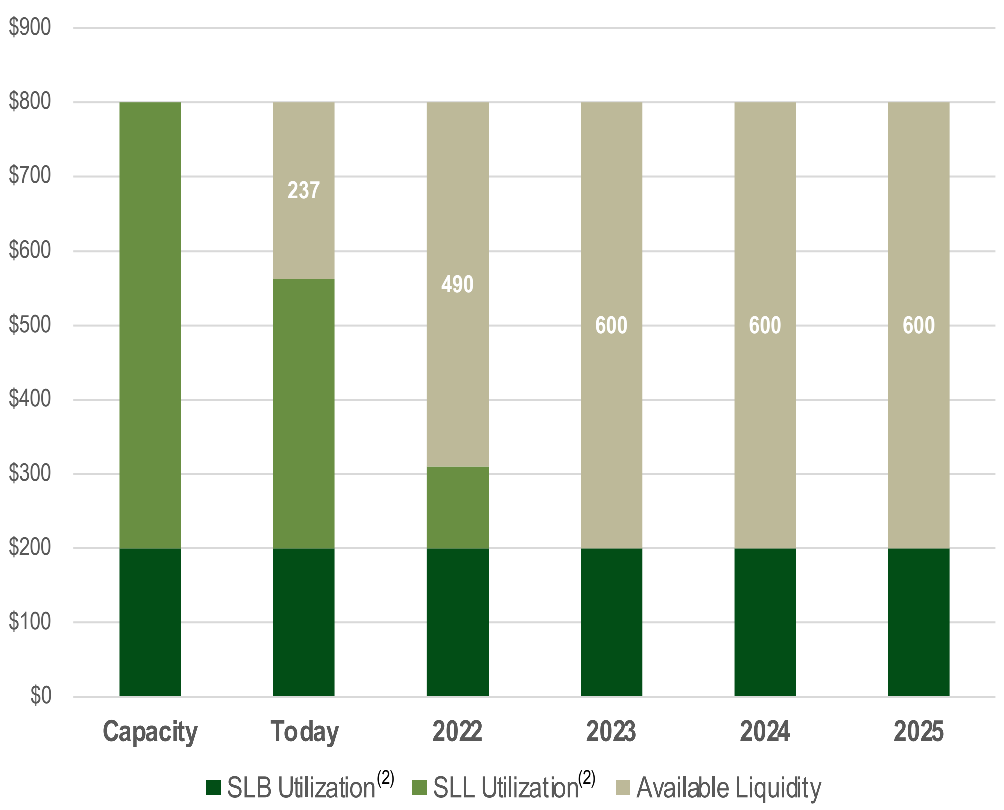
Net Debt[1] Profile ($ millions)



Liquidity and Debt Utilization ($ millions)

US$70 WTI



Sustainability-Linked Lending & Notes

Strengthening Our Commitment to Responsible Energy Production

All of Tamarack's debt has been converted to **sustainability-linked debt** and includes:

- A $600 million revolving **sustainability-linked lending facility** (**SLL**) with a lending syndicate – 3 KPIs with potential annual penalty or benefit
- $200 million notes issued as **sustainability-linked bonds** (**SLB**) that trade in the open market – 2 KPIs with step-up interest penalty in 2026

KPIs and SPTs selected strongly align with Tamarack's **existing priority topics and commitments**

Key Performance Indicator	Tamarack Priority	UN Sustainable Development Goal	2020 Baseline	SLL ($600 million)		SLB ($200 million)	
				Sustainability Performance Target	Penalty/ Benefit	Sustainability Performance Target	Penalty
Scope 1 and 2 emissions intensity		13 CLIMATE ACTION	37.5 kg CO_2e/boe	**39%** reduction by 2025	**+/- 0.025%** +/- $0.75MM over 5 years	**39%** reduction by 2025	**+ 0.75%** $1.0 MM in 2026
Decommissioning Management – ARO spend		15 LIFE ON LAND	5.6%	**150%** of the regulatory target spend annually	**+/- 0.015%** +/- $0.45MM over 5 years		
Indigenous representation in the workforce		10 REDUCED INEQUALITIES	3.5%	**>6.0%** by 2025 with a minimum 2 FTE additions each year	**+/- 0.010%** +/- $0.30MM over 5 years	**>6.0%** representation by 2025	**+ 0.25%** $0.50MM in 2026
Total Potential Penalty					**$1.5MM**		**$1.5MM**

5-Year Plan Anchors Long Term Sustainability

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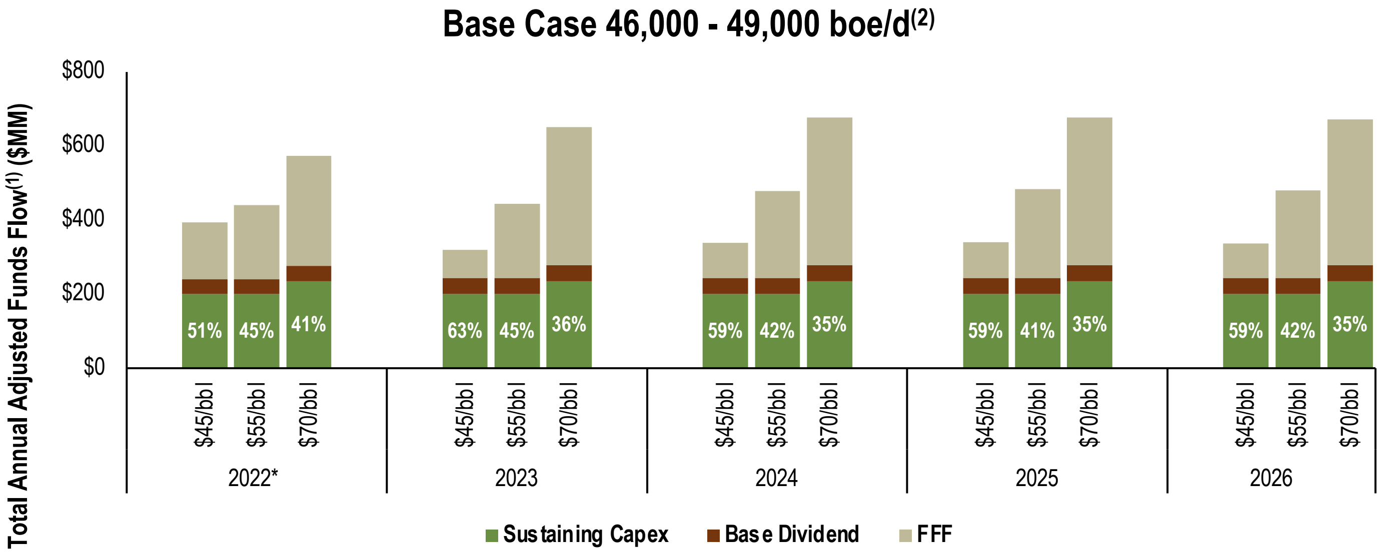
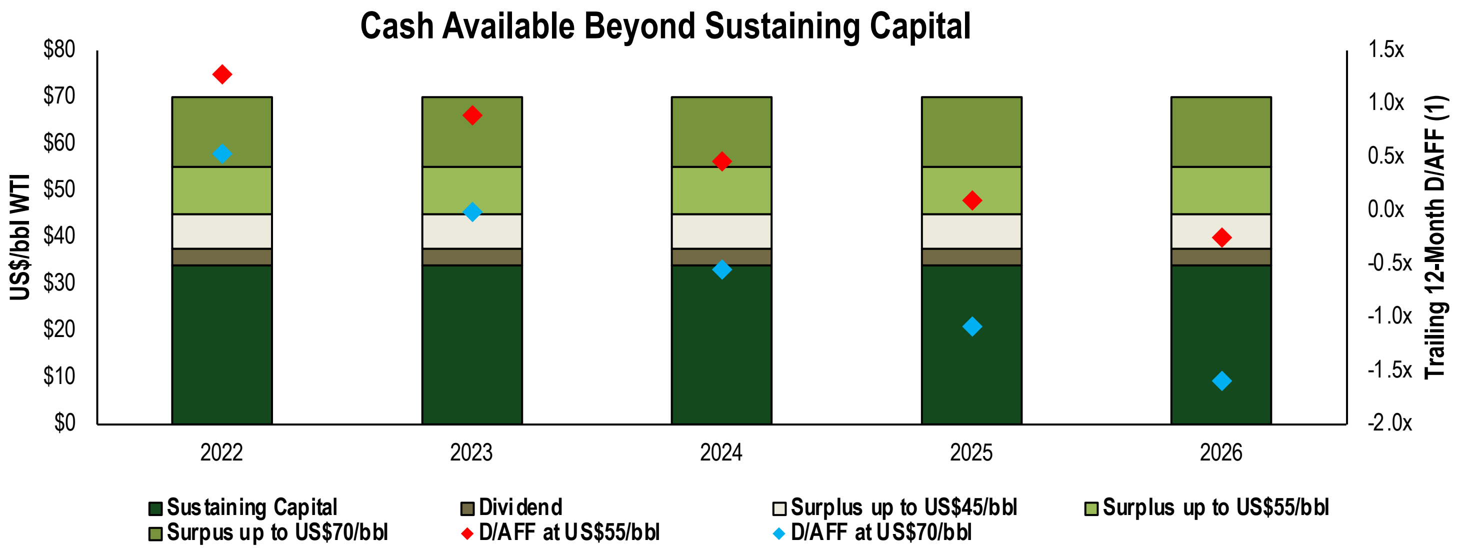
5-Year Plan Overview *(BTAX US$55/bbl WTI & $2.50/GJ AECO)*	
E&D Capital Spending	**$1.1B - $1.3B** *($240MM - $270MM/yr)*
Corporate FFF[(1)] Generation	**$1.1B - $1.2B** *($180MM - $240MM/yr)*
Free Funds Flow Breakeven[(1)]	**~US$35/bbl WTI** *(includes Base Dividends)*
Sustaining Capital as % of Adjusted Funds Flow[(1)]	**40% - 45%**
Target Long-term Leverage	**0.5x – 1.0x D/AFF[(1)]**





Transformative 2021 Enhances Focused Inventory

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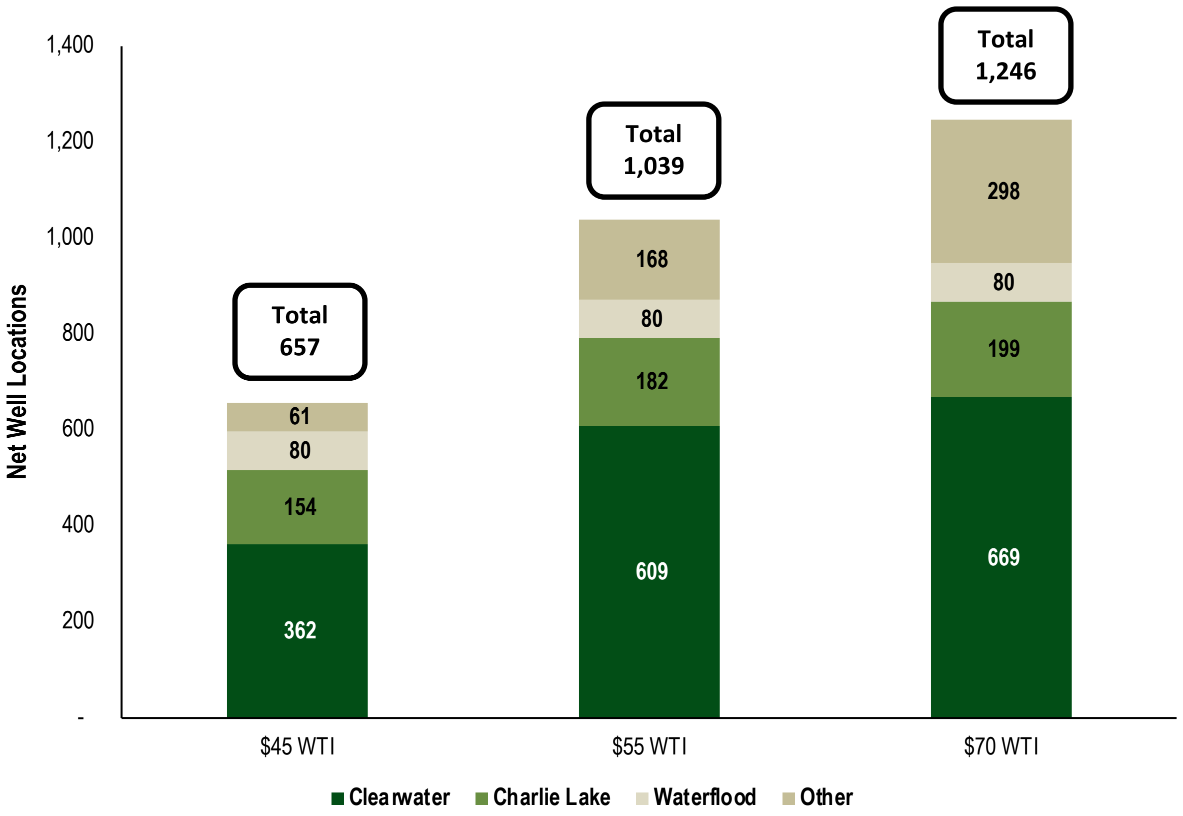
Balancing Duration with Free Funds Flow[1] Growth

Inventory of Net Locations[2]

(assumes payout <18 months)



Drilling 90 – 100 wells per year

HIGHLY ECONOMIC INVENTORY SUPPORTS LONG TERM SUSTAINABILITY

- Strategic inventory management
  - Retain multiple years of high-graded drilling inventory
  - Continue to de-risk future locations to offset annual drilling
  - Combination of high PIR waterflood projects with quick payout Charlie Lake and Clearwater inventory
- Ability to further increase free funds flow[1] by ~5% by adding <2% production annually
- Base case development implies inventory of >10 years[3]

Flexibility to enhance total shareholder return through return of capital, incremental organic growth or M&A opportunities

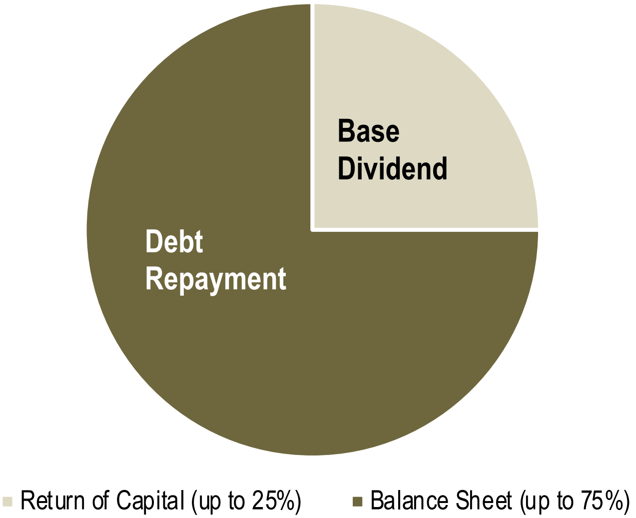
Framework for Returning Capital to Shareholders

Sustaining Capital & Base Dividend Protected Down to US$35/bbl WTI

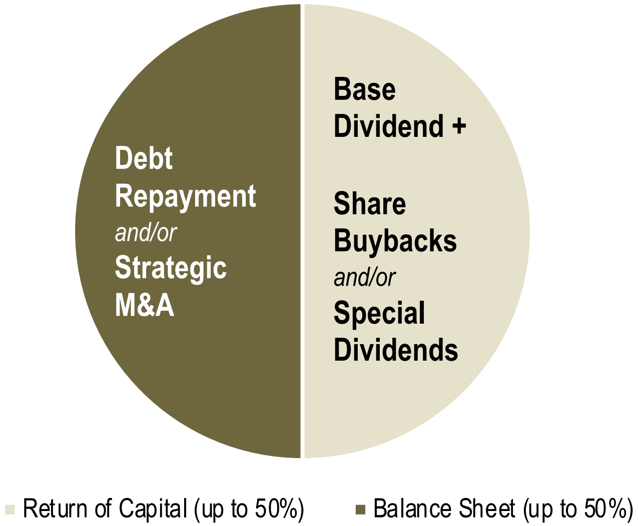
Delivering Enhanced Returns to Shareholders

Free Funds Flow[1] Allocation

Net Debt[1] ≥$375MM



Net Debt[1] $325MM-$375MM[2]

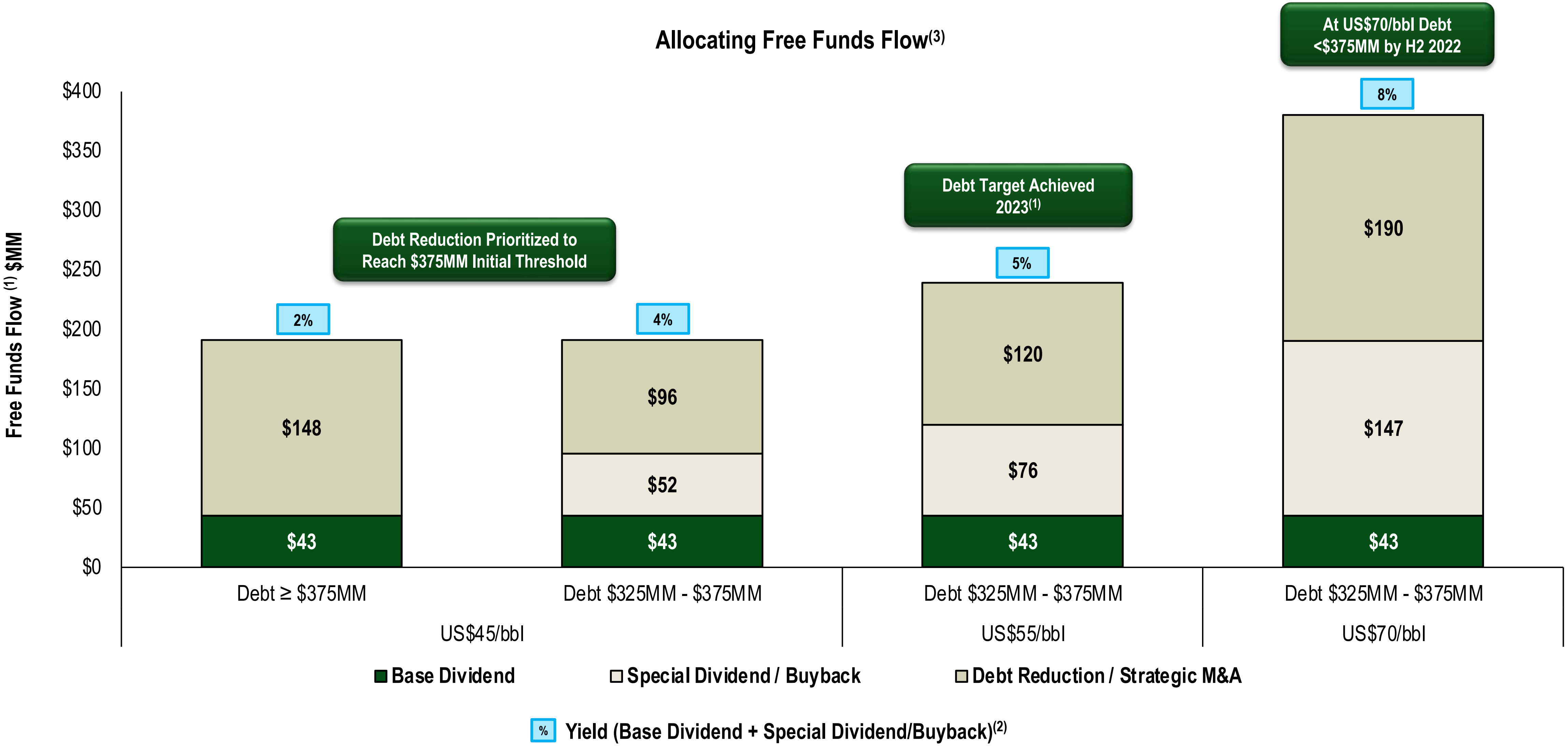


Continuing to Build for the Future w/ 10+ Years of Drilling Inventory

Sustaining Capital Reinvestment Requires <50% of Free Funds Flow[1]

Illustrating Annual Shareholder Return Potential

Strip Pricing Enables Enhanced Return in mid-2022



Positioned in the Top FFF[(1)] Oil Plays in North America

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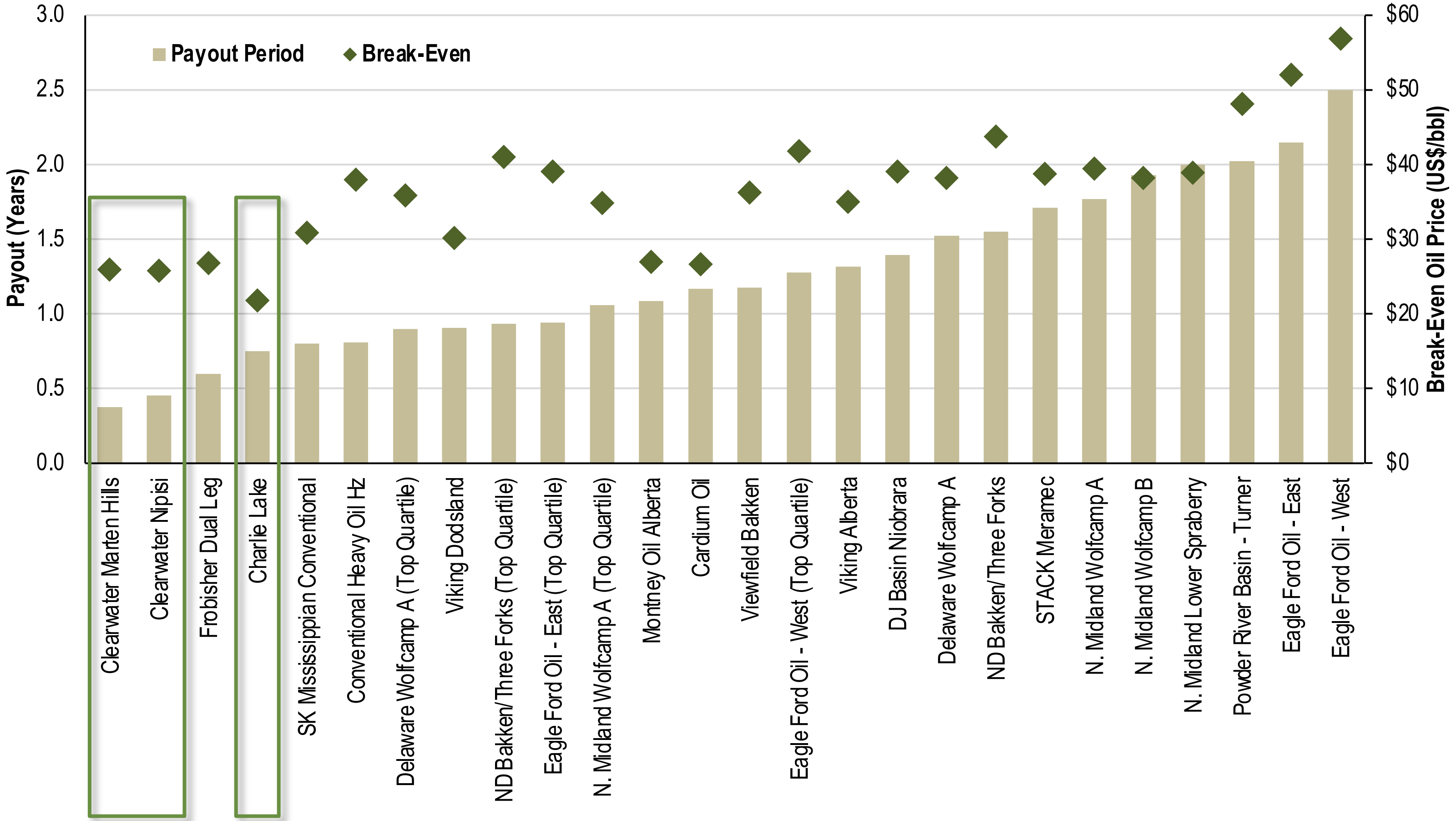
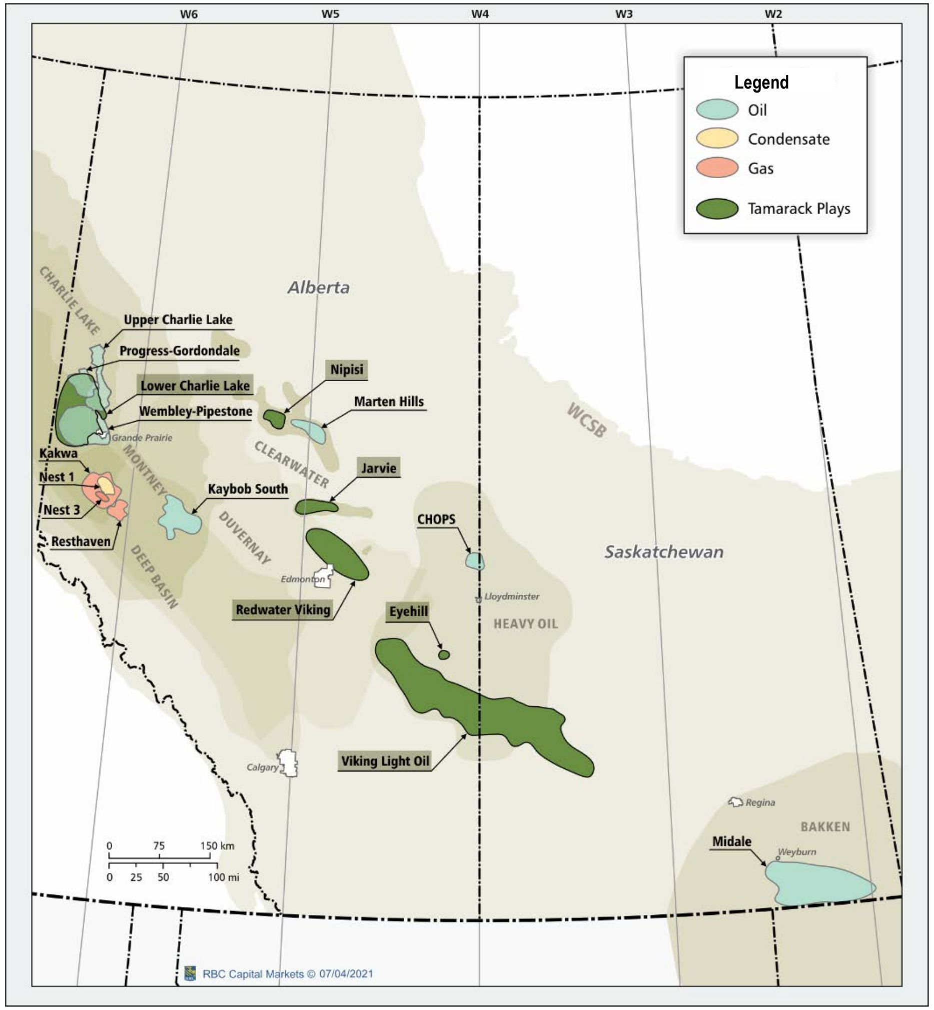
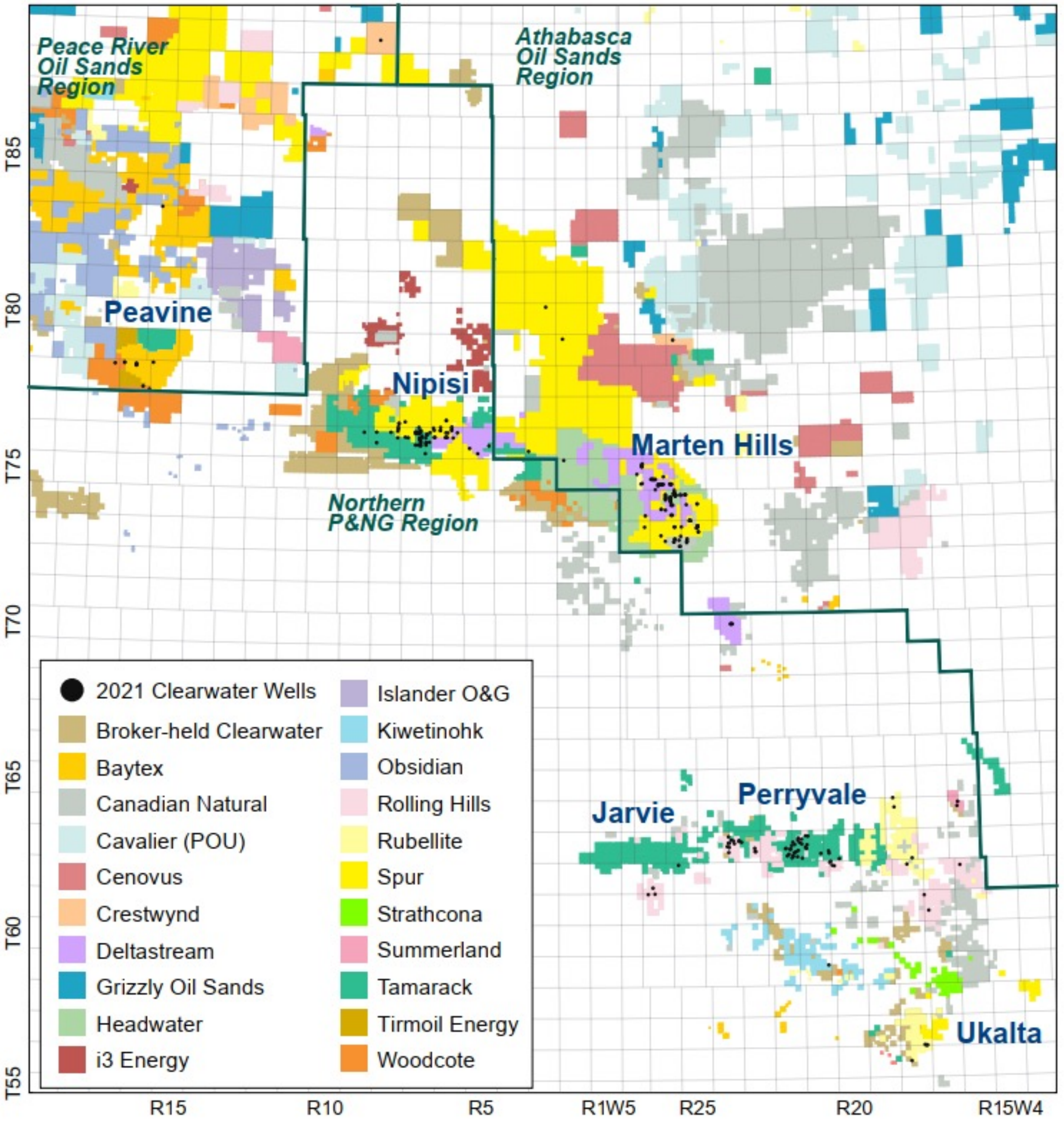
North American Payout Period & Half-Cycle Breakeven by Play





Source: Peters & Co. Limited estimates based on US$70/B WTI, US$3.50/Mcf NYMEX and C$3.25/Mcf AECO prices.

Clearwater Fairway



Source: Peters & Co. Limited and geoSCOUT

Tamarack Clearwater Land Holdings	
Peavine	**29.5** net section in conjunction with the Peavine Metis Settlement strategic land arrangement
Nipisi	**162.3** net sections through corporate and asset acquisitions in 2020 and 2021
West Marten Hills	**38.4** net sections in West Marten Hills in the early stage of development
South Clearwater	**268.0** net sections in South Clearwater including Jarvie, Perryvale and Ukalta
Total Clearwater	**498.2** net sections in the Clearwater fairway

Nipisi & West Marten Hills

Derisking acreage to enhance development inventory

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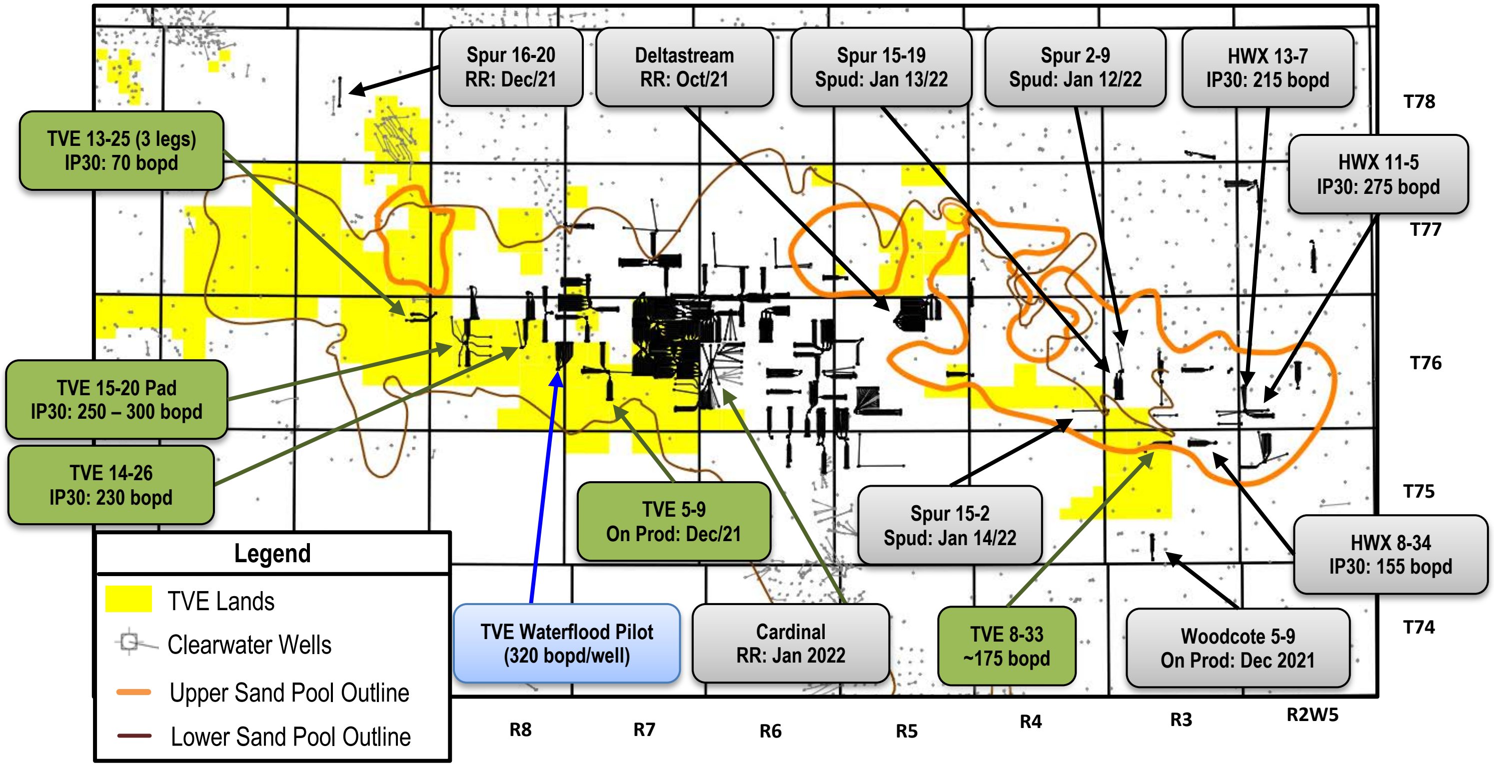
West Marten Hills

Increased Activity	Multiple sands tested by TVE & regional competitors
Derisking Results	IP30 rates of 155 – 275 bopd Oil gravity upper ~19◦ API range

West Nipisi

Increased Activity	Spur 16-20 offsetting TVE's northern lands
Derisking Results	IP30 rates of 250 – 300 bopd Oil gravity ~19◦ API
Waterflood Pilot	TVE to commence injection Q2/22 12 additional waterflood wells planned for '22



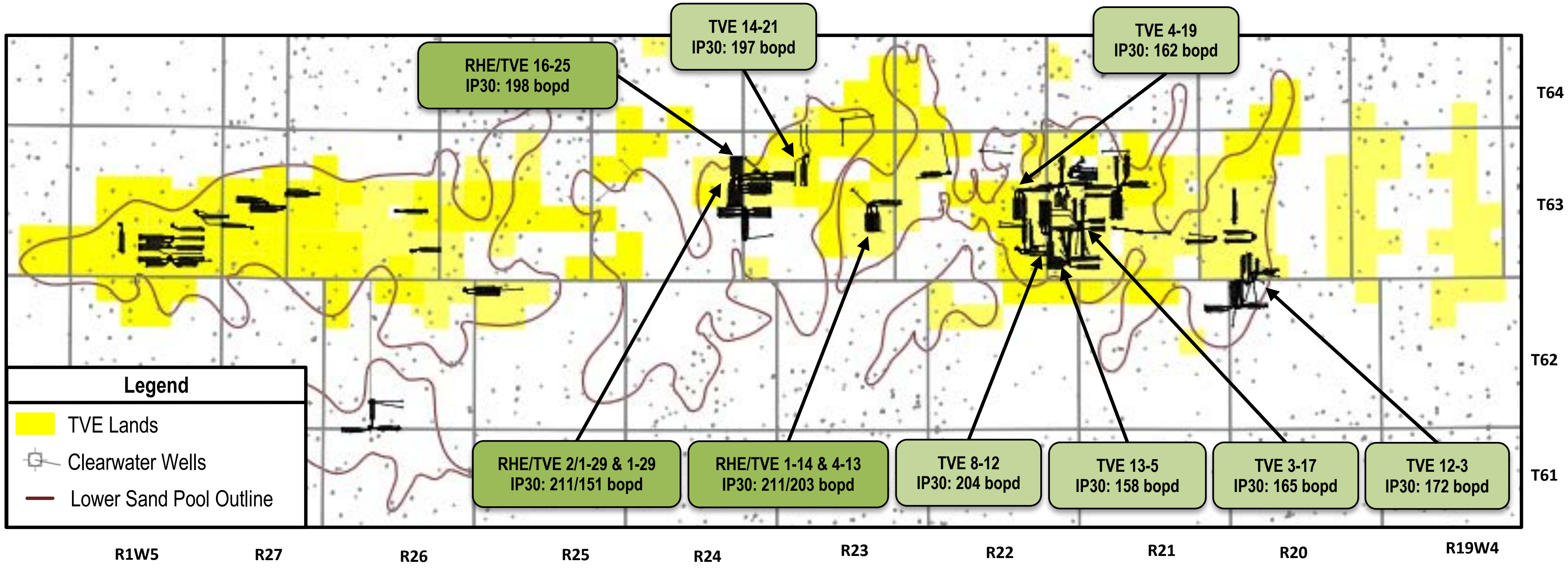
200.7 net Clearwater sections
41 net booked locations(1)
>310 net unbooked locations(1)

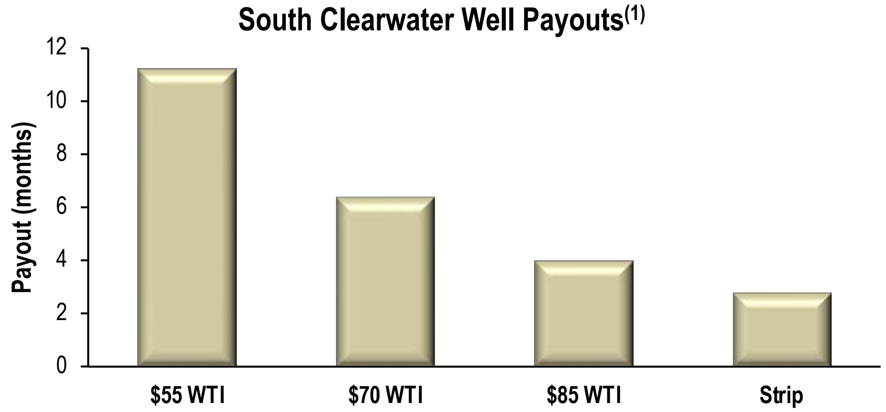
Southern Clearwater

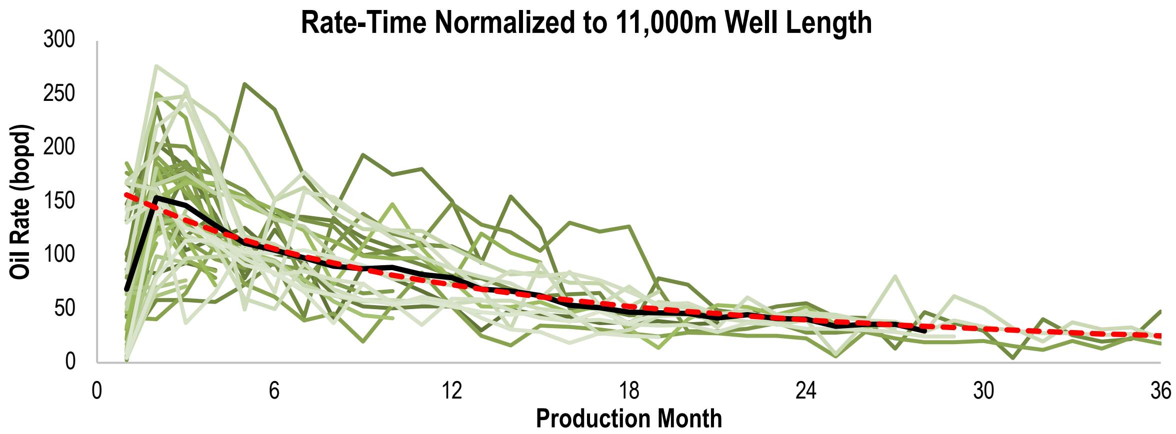
Achieving payout[1] in ~4 months at US$85/bbl to drive free funds flow[2]

Southern Clearwater

Dominant Position	268 net Clearwater sections
Long-term Inventory[3]	112 net booked wells 190 net unbooked wells
Low Cost Structure	Free funds flow breakeven[2] <$35/boe







Clearwater Waterflood Potential

Leveraging promising results from offsetting competitor pilots

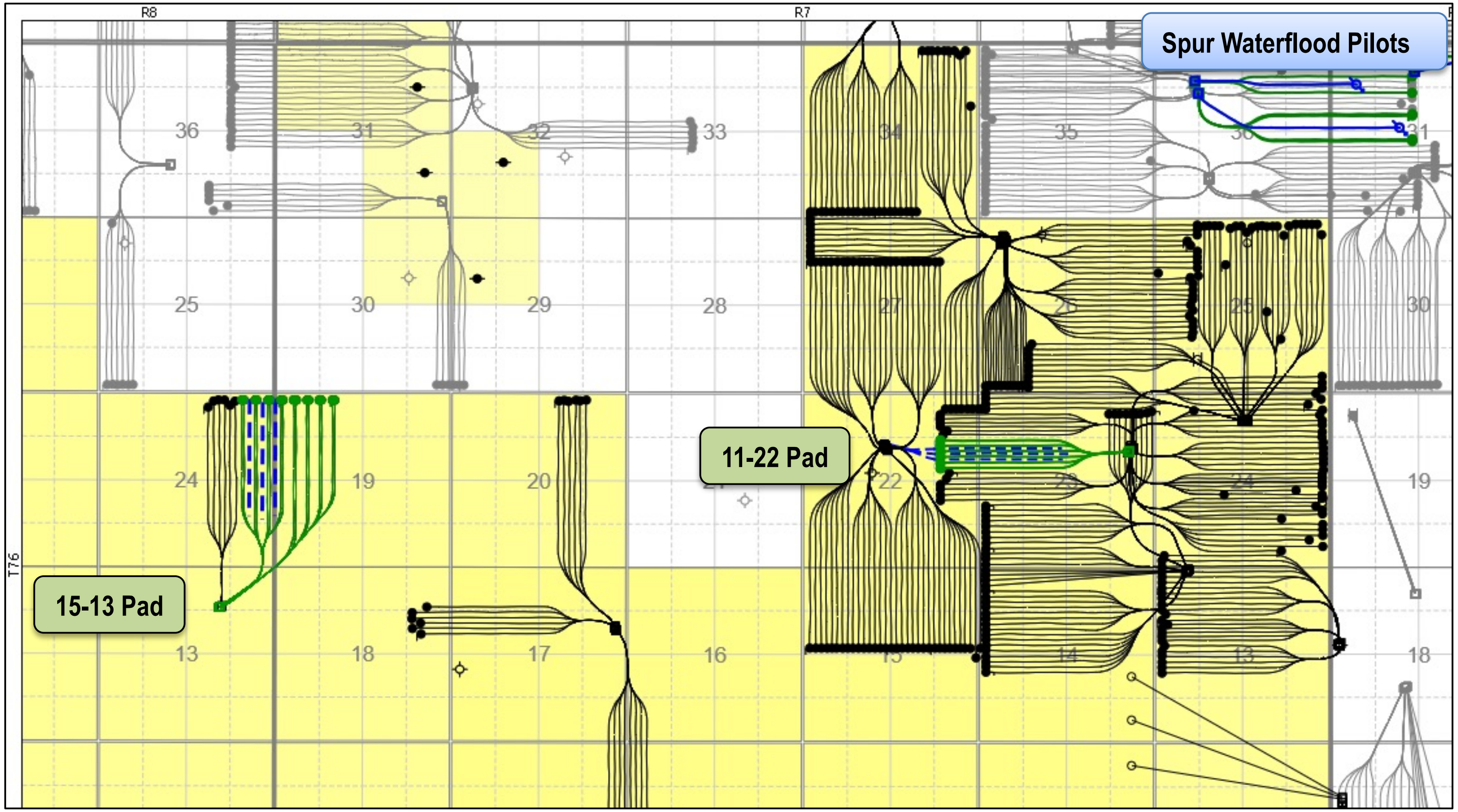
15-13 Pad Pilot

- 2 x 8-leg producers onstream Q4-2021
- Staggered leg spacing (“two-step”) allows for water injection corridors while maintaining near-term productivity
- 3 x single leg injectors drilled Q1-2022 will maximize appraisal information

11-22 Pad Pilot

- Multi-lateral injector trial in primary development region in H2-2022
- Appraisal of well spacing and interlocking multi-lateral layout

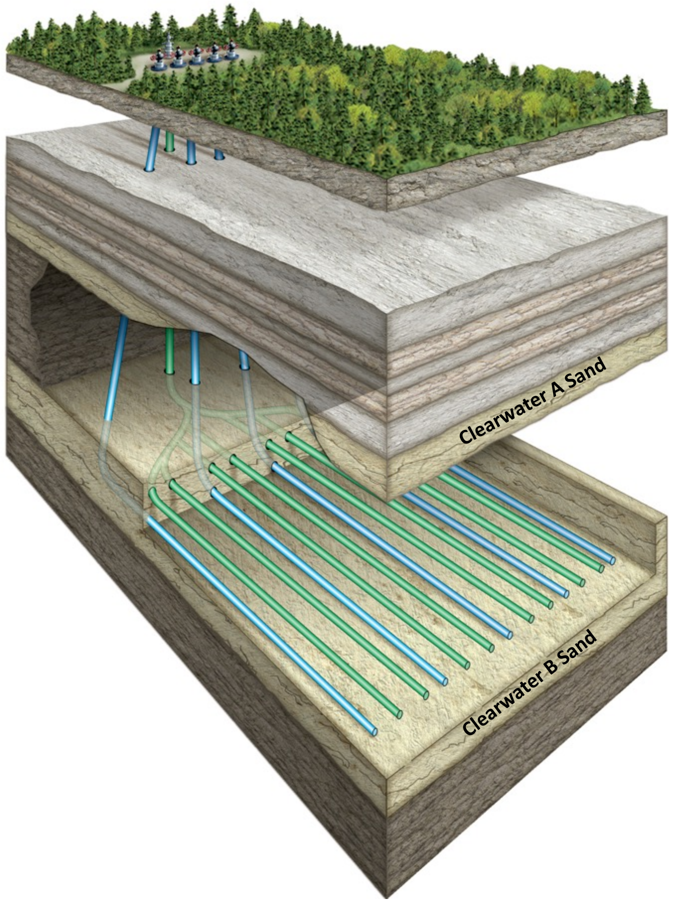
Upcoming Tamarack Nipisi EOR Pilots



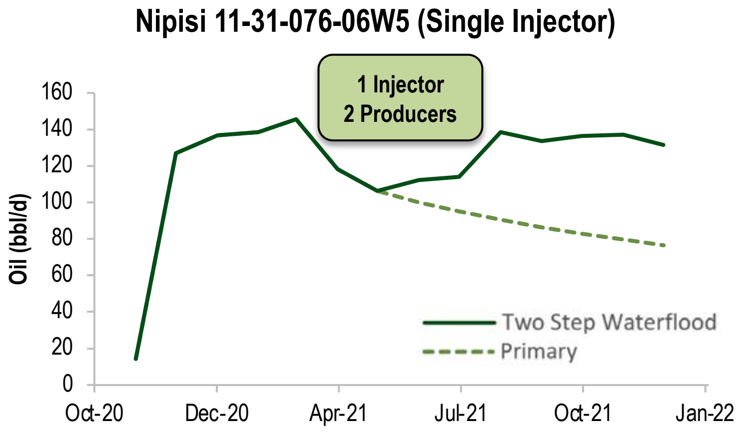
Nipisi Waterflood Design

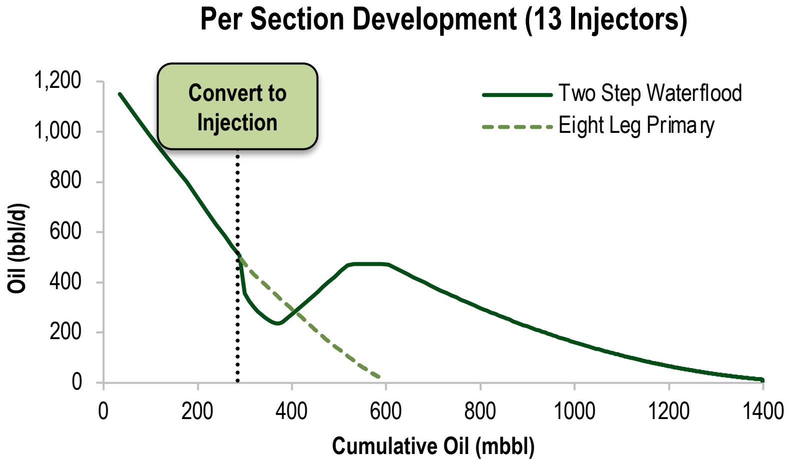
Substantial fairway has been delineated and is ready for development

"Two Step" Waterflood Design

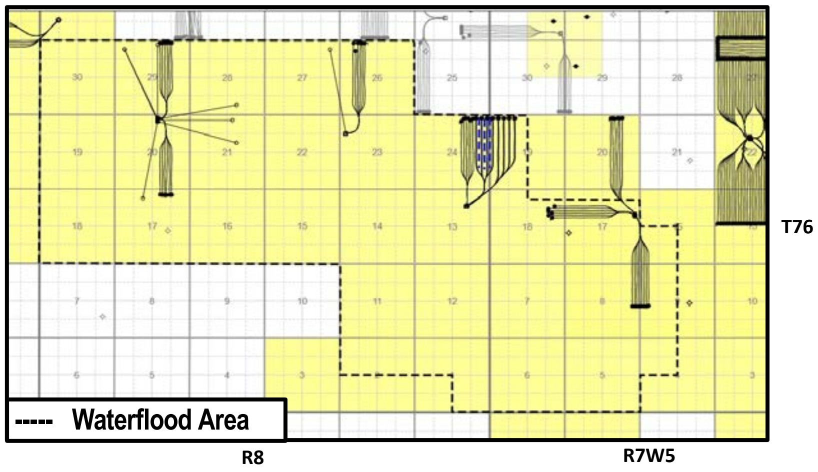


"Two Step" Waterflood Pilot





Potential Waterflood Development Area



Per Developed Section (50m Spacing)	Capex ($MM)	NPV10 ($MM)[1]
Primary	5.1	19.4
Waterflood	10.1	25.9

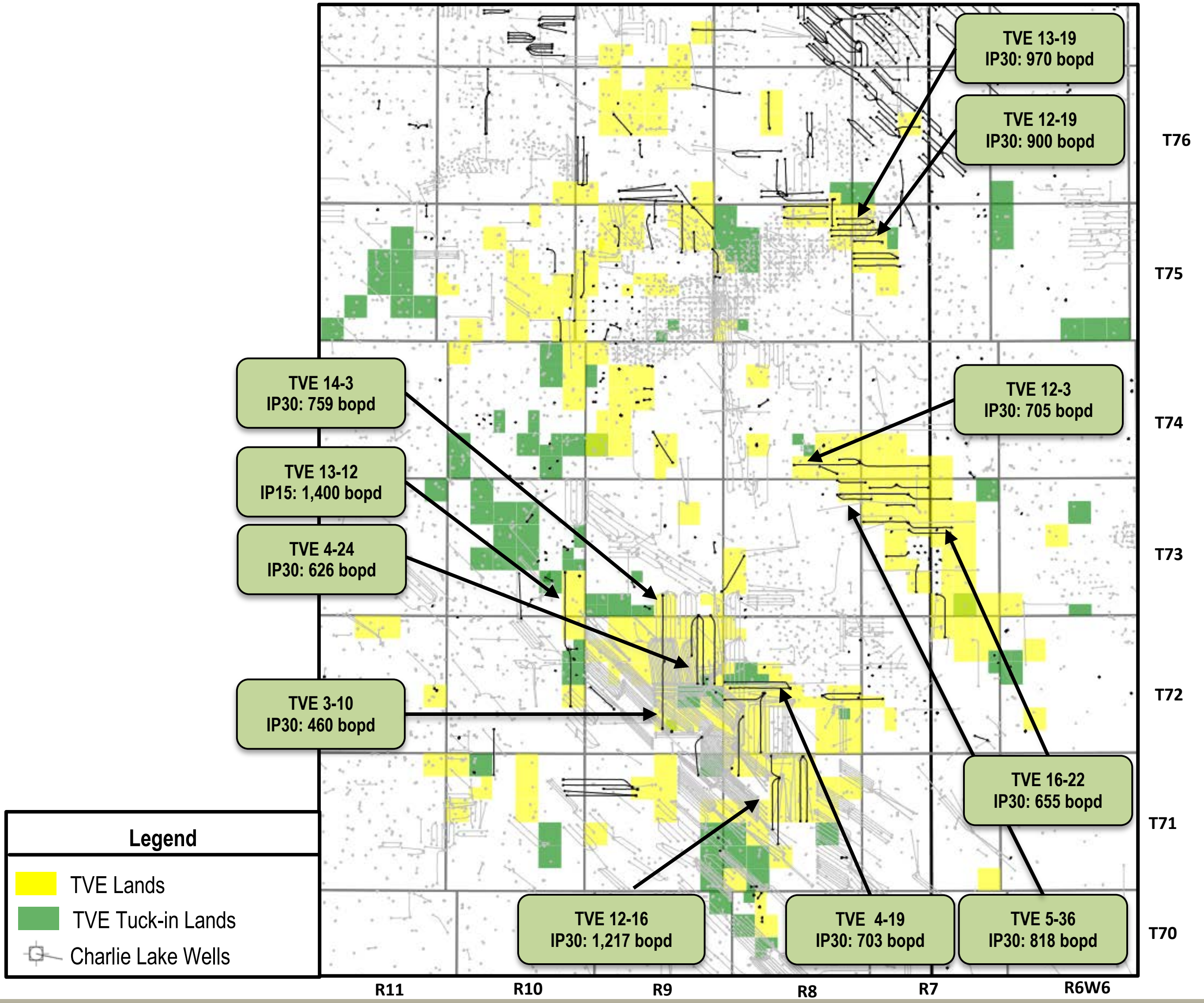
1. Based on US$70/bbl WTI

Charlie Lake Development

Continuing to Increase Our Presence With Added Lands & Prolific Wells

Charlie Lake	
Expanded Footprint	2021 tuck-ins added 35.9 net sections and 63 net Hz locations[(1)]
Unlocking Inventory	Drilling our first Upper Charlie Lake well at Saddle Hills
Step Out Success	Pipestone wells delivering IP rates of 460 – 1,400 bopd
Infrastructure Ownership	Ownership interest in key gas plants
Capacity for Growth	Processing and egress contracts to facilitate long-term development

326.5 net Charlie Lake sections
96.4 net booked locations[(1)]
150.0 net unbooked locations[(1)]



Tamarack's Waterflood Assets

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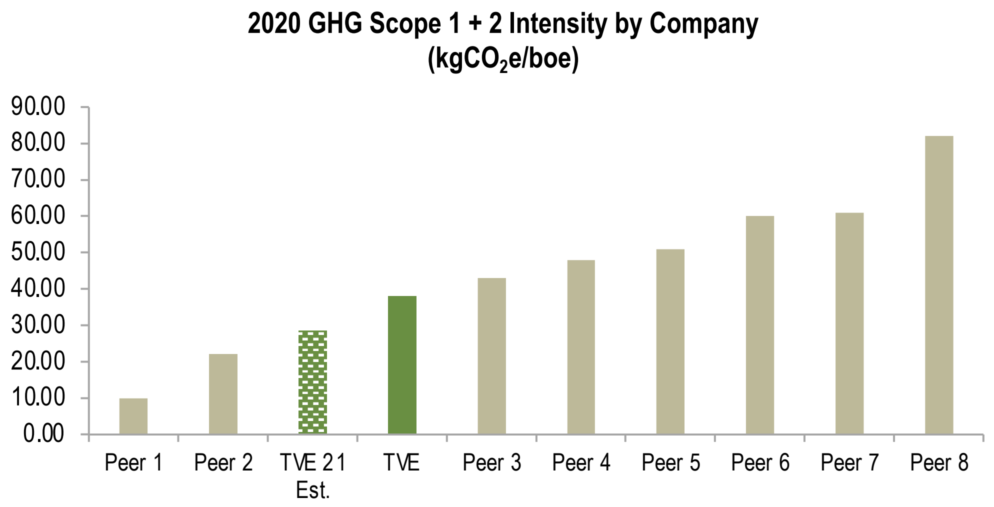
Improving corporate declines with increasing exposure to assets under waterflood

Asset	Total Area Prod.	Prod. Under Waterflood	Total Asset OOIP[1]	Est. Recovery to Date[2]	Est. Ultimate Recovery[2]	Injection Start	% of P+P Reserves	Current Initiatives
Veteran Viking *Light Oil*	3,500 bbl/d	2,300 bbl/d under active waterflood	900 to 1,000 MMbbl	2%	17%	2018	44%	Focus on new linedrive pattern development in North Veteran (including pipeline infrastructure) and start injection on first East Consort stepout injection pattern during 2022
Eyehill Sparky *Medium Oil*	1,800 bbl/d	1,350 bbl/d under active waterflood	200 MMbbl	2%	15%	2014	54%	Continue to increase make-up water supply, complete 5 injector conversions and add 9 new Sparky producers during 2022
Penny Barons *Light Oil*	850 bbl/d	850 bbl/d (entire pool)	60 MMbbl	15%	21%	2001	100%	Actively managing injection for optimal area-based recovery factors, additional infill locations identified
Nipisi Slave Point *Light Oil*	475 bbl/d	475 bbl/d (entire pool)	40 MMbbl	8%	20%	2013	100%	Identify injector conversions to improve waterflood performance, evaluate opportunities for infill producers after injection optimization
Nipisi Clearwater *Medium Oil*	5,500 bbl/d	Injection starting in 1-2 months	15 to 20 MMbbl per section in selected areas	<1%	Up to 20% in selected areas	2022	-	Two-step producers onstream Q4-2021 in single-leg injection pilot area, 3 injectors to be drilled in Q1-2022 (single legs) and 1 in Q2-2022 (multilateral) within 2 pilot focus areas

~5,000 bbl/d under waterflood at <u>0% decline</u> (~20% of Tamarack's pro forma oil production)

Tamarack Sustainability Results

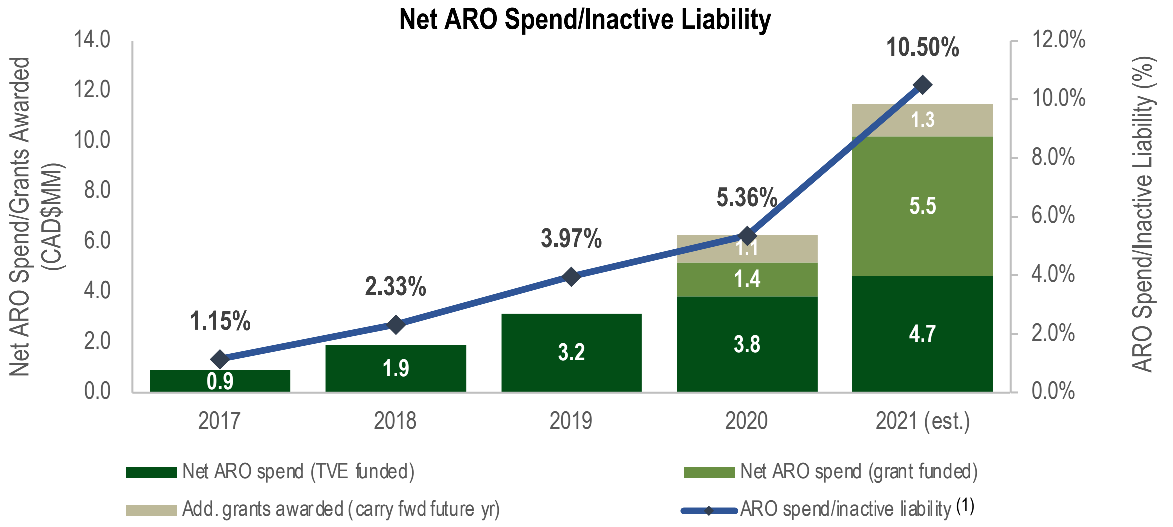
Emissions Intensity



Peers Include: ARC, Baytex, Cenovus, CNRL, Crescent Point, Enerplus, Suncor, Whitecap

TVE is forecasting a Scope 1 +2 emissions intensity of 28.5 $kgCO_2e$/boe for 2021

Land Management



*Understanding and managing risks enables sustainability and ESG to **drive profit** and **enhance future value***

Sustainability Initiatives at Tamarack

Indigenous Engagement

Tamarack is **committed to** the **principles of UNDRIP** and participating in reconciliatory activities. 2021 year-to-date projects include:

- Furthered **workforce participation** goals – team members include three Indigenous women in head office
- **Cultural initiatives** (interactive educational tools for teens)
- **Economic opportunities** and **employment** for First Nations individuals and businesses
- **Indigenous site rehabilitation program support** for indigenous business opportunities and reduction of environmental liabilities

Tamarack is **actively engaging** with **Treaty 8 Nations** in the Nipisi area and the **Kainai Nation** in the Lethbridge area.

Environmental Initiatives

To ensure achievement of long-term goals and targets, Tamarack undertakes regular initiatives including:

Nipisi Gas Conservation	***60 → 28 kgCO_2e/boe*** *through process modifications and gas conservation in the new Nipisi asset*
Operational Efficiency Reviews	***↓~6,000 tCO_2e annually*** *through the removal of six booster compressors in the Westerose asset*
Eyehill Fresh Water Reductions	***100% utilization*** *of non-freshwater in Eyehill for EOR and completion on a go forward basis*
Area Based Abandonment	***85 gross wells*** *abandoned through efficient area-based programs designed to maximize efficiency*
Increasing Leg Count in Multileg Wells	***6 → 8 legs*** *in multileg horizontals enables more efficient drainage with less surface land disturbance*

Investment Summary

Track record of meeting and exceeding estimates

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Sustainable Returns Focused Strategy to Grow Production and Free Funds Flow[(1)] per Share

Management team that has demonstrated its ability to execute and capitalize on opportunities

Stable Base Production and AFF[(1)]

45,000 – 46,000 boe/d
<US$35 WTI free funds flow breakeven[(1)]

Economic Oil Weighted Inventory

Highly economic oil plays focused in the Charlie Lake and Clearwater with EOR in Viking & Sparky

Optionality

Commodity exposure, exploration upside and decline management through waterflood

Balance Sheet Strength and Risk Management

Low leverage and consistent hedging

Leading ESG Practices

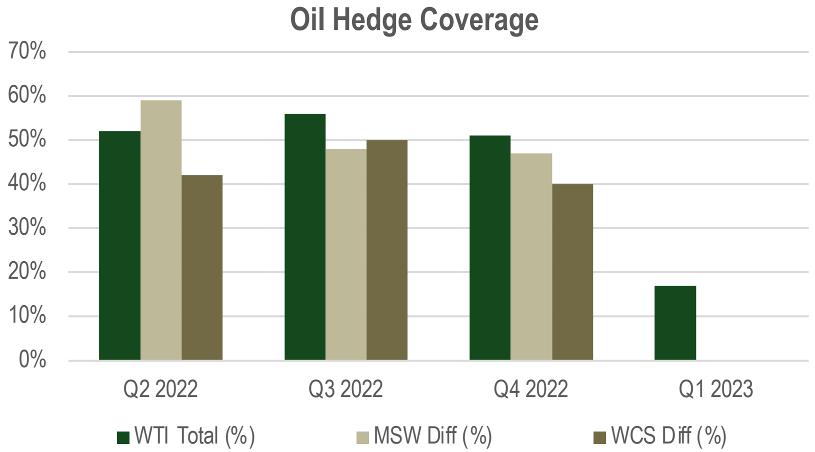
Indigenous partners, low GHG intensity and responsible ARO management

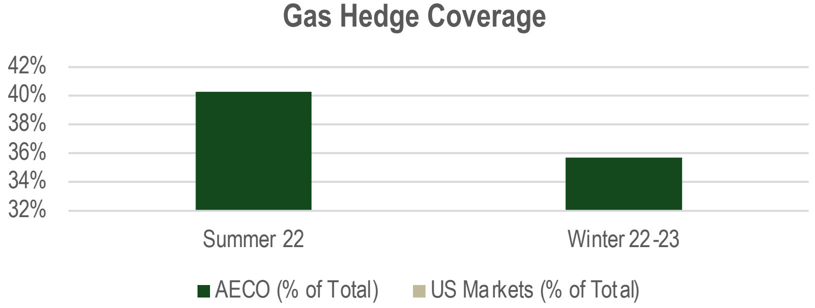
APPENDIX

Risk Management – Current Hedges[1]

Enhancing certainty with flexibility to capture upside value

53%
Oil price protection in 2022[2]





	Q2 2022	Q3 2022	Q4 2022	Q1 2023
WTI Put				
Volume (bbls/d)	**9,000**	**4,750**	**4,250**	**1,000**
Average Put/Premium (USD/bbl)	$62.48 $3.68	$55.75 $3.00	$56.43 $3.18	$60.00 $3.27
WTI 2-way collar				
Volume (bbls/d)	**4,250**	**11,750**	**12,000**	**4,500**
Average Put/Call/Premium (USD/bbl)	$55.35 $90.46 $2.12	$58.87 $95.15 $1.95	$57.48 $106.18 $1.95	$56.67 $117.52 $2.00
WTI 3-way collar (reverse)				
Volume (bbls/d)	**2,500**	**1,250**	**750**	
Average Put/Call/Sold Put/Premium (USD/bbl)	$54 $70 $73 $2	$55 $70 $73 $2	$55 $70 $74 $2	
Edm Par Diff				
Volume (bbls/d)	**10,500**	**8,000**	**8,000**	
Average Fixed Price (USD/bbl)	($3.66)	($3.60)	($3.60)	
WCS Diff				
Volume (bbls/d)	**5,000**	**7,500**	**5,500**	
Average Fixed Price (USD/bbl)	($11.82)	($12.00)	($12.09)	

Crestwynd	Q2 2022
WTI fixed price	
Volume (bbls/d)	
Average Fixed Price (CAD/bbl)	
WTI 2-way collar	
Volume (bbls/d)	**500**
Average Put/Call (CAD/bbl)	$75.00 $96.01
WCS Diff	
Volume (bbls/d)	**500**
Average Fixed Price (CAD/bbl)	($14.85)

	Summer 22	Winter 22-23
AECO 5A fixed price		
Volume (GJ/d)	**30,000**	**10,000**
Average Price (CAD/GJ)	$2.44	$3.85
AECO 7A collars		
Volume (GJ/d)		**15,000**
Average Put/Call (CAD/GJ)		$3.37 $5.17

2022 Budget Highlights

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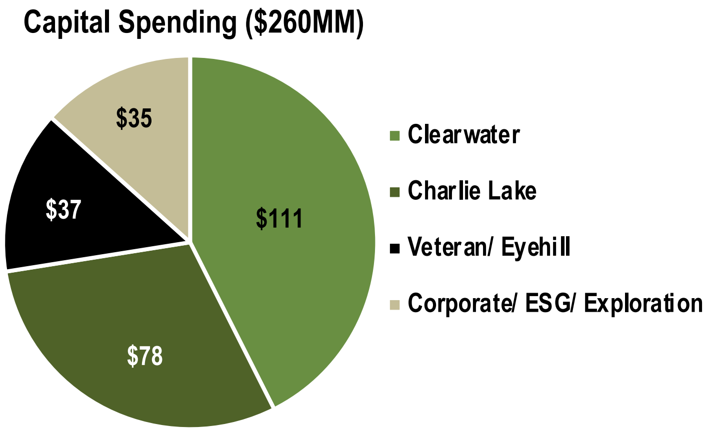

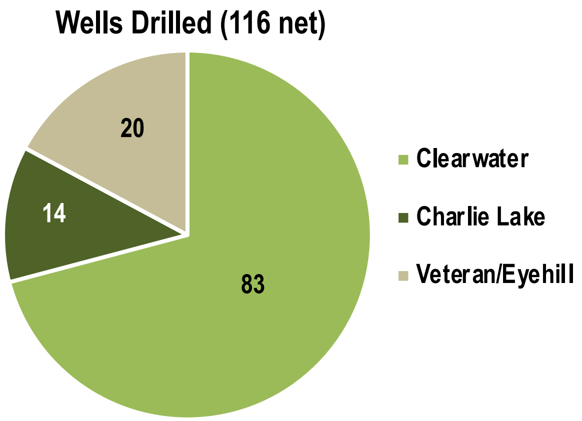

Focused Capital Deployment	• *Investing $250MM to $270MM of annual capital* • *Drilling 126 (116 net) wells targeting the Clearwater, Charlie Lake & Waterflood projects*
Optimized Production	• *Drilling activity drives volumes of 45,000 – 46,000 boe/d (73-75% liquids)* • *Allocating 25% of capital to low decline EOR initiatives in the Nipsi Clearwater, Veteran and Eyehill areas*
Sustainable Free Funds Flow(1)	• *Capital program funded through <50% of adjusted funds flow(1)* • *Sustaining free funds flow breakeven(1) ~US$35/bbl inclusive of base dividend*
Supporting Return of Capital	• *Maintain a strong balance sheet to underpin financial flexibility* • *Initial dividend to be paid Feb 15 as part of the return of capital framework*
ESG Commitment	• *Allocating $7.5MM to ARO spending* • *Investing $3.5MM in gas conservation infrastructure & emissions reductions*

Return of Capital Strategy

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Sustainable Base Dividend

- Predicated on up to 25% of free funds flow[(1)] at US$55 WTI and $2.50/GJ AECO
    - Sustaining capital + base dividend is fully fundable down to US$35/bbl WTI and would represent only 37% payout on current strip
- Up to 75% for debt repayment, strategic M&A and ESG initiatives

Sustainable Base Dividend Growth

- The base dividend would target small annual growth aligned with earnings and macro economic outlook

+

Enhanced Return to Shareholders

- Long-term debt target of $325MM - $375MM threshold TVE plans to return up to 50% of the **PRIOR QUARTER** free funds flow[(1)] **INCLUDING BASE DIVIDENDS** to shareholders
- **Tactical share buybacks (pending approval of NCIB by the TSX) and/or special dividends**
    - Evaluating buyback vs. special dividend: consideration of intrinsic value, FFF[(1)] yield, relative market valuation and macro conditions
- **Remaining 50% of free funds flow directed to the balance sheet for future M&A and or other opportunities**
- Enhanced returns evaluated in the context of overall market conditions

The long-term net debt[(1)] target of $325MM - $375MM predicated on 1.0x D/AFF[(1)] at US$45/bbl WTI

Corporate Information

Executive

Brian Schmidt (Aakaikkitstaki)	President & Chief Executive Officer
Steve Buytels	VP Finance & Chief Financial Officer
Kevin Screen	Chief Operating Officer
Martin Malek	VP Engineering
Christine Ezinga	VP Corporate Planning & Business Development
Scott Shimek	VP Production & Operations

Board of Directors

John Rooney (1,3,4)	Chairman
Brian Schmidt (Aakaikkitstaki)	President & Chief Executive Officer
Jeff Boyce (1,2)	Independent Director
Ian Currie (2,4)	Independent Director
John Leach (1,2)	Independent Director
Marnie Smith (1,3)	Independent Director
Robert Spitzer (2,3)	Independent Director

1. Member of Audit Committee of the Board of Directors
2. Member of the Reserves Committee of the Board of Directors
3. Member of the Governance & Compensation Committee of the Board of Directors
4. Member of the Environment, Safety & Sustainability Committee

Independent Reserve Evaluator

GLJ Petroleum Consultants

Auditors

KPMG LLP

Legal Counsel

Stikeman Elliott LLP

Banking Syndicate Lead

National Bank of Canada

Head Office

Jamieson Place
Suite 3300, 308 - 4th Ave S.W.
Calgary, AB T2P 0H7

Phone: 403.263.4440

www.tamarackvalley.ca

Investor Contact Information

Brian Schmidt
President & Chief Executive Officer

or

Steve Buytels
VP Finance & Chief Financial Officer

Notes

Page 5

1. See Disclaimers – “Specified Financial Measures”; free funds flow and free funds breakeven were formerly referred to as free adjusted funds flow and free adjusted funds flow breakeven respectively
2. Year-end 2021 pro forma the cash costs of the Crestwynd acquisition
3. Tax pools as at year-end 2021
4. 2022 pricing assumptions: WTI US$70/bbl, MSW/WTI differential of US$4.00/bbl, WCS/WTI differential of US$14.00/bbl, AECO at $3/GJ and exchange rate of 1.28
5. Comprised of 16,750-17,250 bbl/d light and medium oil, 13,000-13,250 bbl/d heavy oil, 3,750-4,000 bbl/d NGL and 69,000-71,000 mcf/d natural of

Page 6

1. See Disclaimers – “Specified Financial Measures”; free funds flow was formerly referred to as free adjusted funds flow
2. Sustainability Linked Loan (SLL)
3. Comprised of 18,487 bbl/d light and medium oil, 5,616 bbl/d heavy oil, 3,899 NGL and 74,291 mcf/d natural gas
4. Comprised of 15,670 bbl/d light and medium oil, 4,613 bbl/d heavy oil, 3,408 NGL and 65,226 mcf/d natural gas

Page 7

1. See Disclaimers – “Specified Financial Measures”; free funds flow and free funds breakeven were formerly referred to as free adjusted funds flow and free adjusted funds flow breakeven respectively

Page 8

1. See Disclaimers – “Specified Financial Measures”; free funds flow and free funds breakeven were formerly referred to as free adjusted funds flow and free adjusted funds flow breakeven respectively

Page 9

1. See Disclaimers – “Specified Financial Measures”;
2. Sustainability Linked Bond (SLB) and Sustainability Linked Loan (SLL)

Page 11

1. See Disclaimers – “Specified Financial Measures”; FFF – Free Funds Flow; AFF – Adjusted Funds Flow; D/AFF – Net debt to annual adjusted funds flow; free funds flow and free funds breakeven were formerly referred to as free adjusted funds flow and free adjusted funds flow breakeven respectively
2. Comprised of 18,000-19,000 bbl/d light and medium oil, 8,500-9,000 bbl/d heavy oil, 3,300-3,500 bbl/d NGL and 67,000-70,000 mcf/d natural gas

Page 12

1. See Disclaimers – “Specified Financial Measures”; free funds flow was formerly referred to as free adjusted funds flow
2. See “Oil and Gas Advisories – Drilling Locations” – locations not updated for changes to reserve categories at year-end
3. At US$55/bbl WTI & $2.50/GJ AECO flat pricing

Notes

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Page 13
1. See Disclaimers – "Specified Financial Measures"; free funds flow was formerly referred to as free adjusted funds flow

Page 14
1. At US$55/bbl WTI & $2.50/GJ AECO
2. Annual yield is calculated as (base dividend plus partial year special dividend where relevant) divided by current market capitalization including shares to be issued with the Crestwynd acquisition
3. See Disclaimers – "Specified Financial Measures"; free funds flow was formerly referred to as free adjusted funds flow

Page 15
1. See Disclaimers – "Specified Financial Measures"; FFF – Free Funds Flow; free funds flow and free funds breakeven were formerly referred to as free adjusted funds flow and free adjusted funds flow breakeven respectively

Page 17
1. See "Oil and Gas Advisories – Drilling Locations"

Page 18
1. See "Oil and Gas Advisories"
2. See Disclaimers – "Specified Financial Measures"; free funds flow was formerly referred to as free adjusted funds flow
3. See "Oil and Gas Advisories – Drilling Locations"

Page 21
1. See "Oil and Gas Advisories – Drilling Locations"

Page 22
1. See "Oil and Gas Advisories"
2. See "Oil and Gas Advisories"

Page 25
1. See Disclaimers – "Specified Financial Measures"; FFF – Free Funds Flow; AFF – Adjusted Funds Flow; D/AFF – Net debt to annual adjusted funds flow; free funds flow and free funds breakeven were formerly referred to as free adjusted funds flow and free adjusted funds flow breakeven respectively

Page 27
1. As at March 2, 2022
2. For Q2 through Q4 2022, including Crestwynd

Page 28
1. See Disclaimers – "Specified Financial Measures"; free funds flow and free funds breakeven were formerly referred to as free adjusted funds flow and free adjusted funds flow breakeven respectively

Page 29
1. See Disclaimers – "Specified Financial Measures"; FFF – Free Funds Flow; AFF – Adjusted Funds Flow; D/AFF – Net debt to annual adjusted funds flow; free funds flow and free funds breakeven were formerly referred to as free adjusted funds flow and free adjusted funds flow breakeven respectively