Tamarack Valley Energy Announces Year-End 2022 Reserves & Financial Results and Provides Operational Update

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CALGARY, March 1, 2023 - Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") is pleased to announce its a
financial and operating results for the three months and year ended December 31, 2022 and the results of Tamarack's
independent oil and gas reserves evaluation as of December 31, 2022 (the "Reserve Report"), prepared by Tamarack's
independent qualified reserves evaluator, GLJ Ltd. ("GLJ"). Selected reserves, financial and operating information is ou
below. Selected financial and operating information should be read with Tamarack's audited annual consolidated financ
statements and related management's discussion and analysis for the three and twelve months ended December 31, 2
are available on SEDAR at www.sedar.com and on Tamarack's website at www.tamarackvalley.ca. The Company's An
Information Form (AIF) for the year ended December 31, 2022 is available on SEDAR and the Company's website.

Message to Shareholders

2022 represented a year of continued transformation and operational execution as we drove towards the goal of reposi
business into the most profitable oil plays in North America. Tamarack completed and integrated three material Clearwa
acquisitions, positioning the Company as a major producer in the Clearwater oil play. Furthermore, the divestment of tw
assets contributed to the strategic rationalization of our asset portfolio moving forward. Together with our ongoing base
development, our net $1.7 billion of 2022 acquisition and disposition (A&D) transactions resulted in a year over year fou
production increase of 59% while also achieving an uplift in our corporate liquids weighting from 69% (Q4 2021) to 82%

2022 was a record year for financial performance with $727.1 million of adjusted funds flow(1) and $268.5 million of free
(1) (excluding acquisition expenditures), which enabled the return of capital to shareholders and established a strong fin
position that provided a foundation for the accretive and transformational 2022 acquisitions. During the year, we initiate
capital framework with our inaugural base dividend and subsequent 50% growth of monthly dividends through the year
$0.0083/share to $0.0125/share. This increase was enabled by the highly accretive Clearwater acquisitions which stren
free funds flow(1) outlook in the corporate five-year plan.

Operational execution was an important success factor in 2022, with fourth quarter production averaging 64,344 boe/d(
our guidance range of 62,000-64,000 boe/d(2), despite unexpected downtime due to the extreme cold weather in Decem
Capital expenditures(3) of $125 million during the fourth quarter came in at the low end of our $125 to $135 million guida

Our 2022 Reserve Report highlights the significant growth, and a shift in profitability, of our reserves, which was driven
development of our Clearwater and Charlie Lake assets. Overall, Tamarack saw a material increase in our reserve port
242.2 MMboe and $5.0 billion(4) on a total proved plus probable (TPP) basis representing a 33% and 68% increase ove
respectively. The year-end 2022 reserves added through acquisition exceeded our original internal reserves estimates,
most notable increase seen for the Deltastream Energy Corp. ("Deltastream") acquisition assets which outperformed es
27% on a proved developed producing (PDP) basis and 12% on a TPP basis.

Along with the transformation of the business operations, Tamarack also underwent a significant transition in capital str
the move away from reserve based into covenant lending and the addition of long-term fixed priced debt. As part of this
Tamarack was able to further demonstrate environmental, social and governance (ESG) leadership through the additio
sustainability targets on the new bond issuances (SLB) and the amended revolving facility (SLL).

2022 Financial and Operating Highlights

- Achieved fourth quarter production volumes of 64,344 boe/d(2) and yearly production volumes of 48,283 boe/d(2) i
  representing a 59% and 40% increase respectively compared to the same periods in 2021.
- Generated adjusted funds flow(1) of $196.7 million for the quarter ($0.36/share basic and diluted) and $727.1 milli
  year ended December 31, 2022 ($1.58/share basic and $1.57/share diluted).
- Generated free funds flow(1), excluding acquisition expenditures, of $268.5 million and net income of $345.2 millio
  year.
- Initiated a return of capital framework with our inaugural monthly base dividend and subsequent monthly dividend
  50% through the year. Collectively, paid or accrued $55.3 million to shareholders through dividends on Tamarack
  shares, including: $0.0083/share for the first five months of 2022; $0.01/share for all dividends declared between
  2022 and October 15, 2022; and $0.0125/share for all dividends declared on November 15, 2022 and after.

- Invested $125.3 million in Q4 towards exploration and development (E&D) capital expenditures, excluding acquis expenditures, and $458.6 million during the full year 2022, which contributed to the drilling of 84 (84.0 net) Clearw wells, 18 (17.2 net) Charlie Lake oil wells, 16 (16.0 net) Deltastream Clearwater oil wells, 13 (13.0 net) Viking oil w two (2.0 net) West Central oil wells.
- Exited the year with $1,357 million of net debt(1). Tamarack will prioritize debt repayment through 2023 to enable reduction and advancement in the Company's enhanced shareholder return framework.

2022 Reserve Highlights

The ongoing positive impact of Tamarack's drilling program combined with Clearwater acquisitions contributed significa reserves in 2022, further enhancing the long-term resiliency and sustainability of free funds flow(1) for the Company mo forward. Key highlights of the Company's proved developed producing (PDP), total proved (TP) and total proved plus p (TPP) reserves from the Reserve Report are highlighted below.

- Increased PDP reserves 35% to 75.7 MMboe, TP reserves 30% to 135.1 Mmboe and TPP reserves 33% to 242.2 2022, relative to year-end 2021.
- Realized before-tax net present value (NPV) of reserves, discounted at 10% (NPV10), of $1.8 billion on a PDP ba billion on a TP basis and $5.0 billion on a TPP basis, evaluated using three independent reserve evaluators avera pricing and foreign exchange rates as at January 2023.
- Recognized finding and development costs (F&D), including the change in future development capital (FDC), of $ $31.59/boe and $37.05/boe for PDP, TP and TPP respectively, which reflects an increase in FDC, due to an incre number of future drilling locations and cost inflation, of $34 million, $375 million and $622 million for the respective For comparative purposes, F&D costs before increases in FDC were $18.64/boe, $21.60/boe and $22.27/boe, res
- Realized a 27% increase for PDP reserves and a 12% increase for TPP reserves, on the acquired Deltastream as the internally estimated reserves at acquisition, driven by strong base production and new drill performance in H2
- Maintained modest booking of Clearwater waterflood reserves, with only 3% of total Clearwater reserves under w TPP Reserves in the area surrounding our successful Nipisi waterflood pilot are greater than 2x the primary recov estimates.

Financial & Operating Results

	Three months ended December 31,			Year ended December 31,		
	2022	2021	% change	2022	2021	% c
($ thousands, except per share)						
Total oil, natural gas and processing revenue	423,760	243,184	74	1,459,154	701,051	108
Cash flow from operating activities	227,889	118,647	92	805,377	297,894	170
Per share - basic	$ 0.42	$ 0.29	45	$ 1.75	$ 0.84	108
Per share - diluted	$ 0.42	$ 0.29	45	$ 1.73	$ 0.83	108
Adjusted funds flow(1)	196,746	124,080	59	727,061	340,259	114
Per share - basic	$ 0.36	$ 0.31	16	$ 1.58	$ 0.96	65
Per share - diluted	$ 0.36	$ 0.30	20	$ 1.57	$ 0.94	67
Net income	50,441	140,448	(64)	345,198	390,508	(12)
Per share - basic	$ 0.09	$ 0.35	(74)	$ 0.75	$ 1.10	(32)
Per share - diluted	$ 0.09	$ 0.34	(74)	$ 0.74	$ 1.08	(31)
Net debt (1)	(1,356,570)	(463,284)	193	(1,356,570)	(463,284)	193
Capital expenditures(1),(3)						

125,276

41,671

201

458,577

191,159

140

Weighted average shares outstanding (thousands)						
Basic	545,118	406,061	34	460,345	353,642	30
Diluted	549,062	413,944	33	464,276	360,779	29
Share Trading						
High	$ 5.60	$ 3.95	42	$ 6.48	$ 3.95	64
Low	$ 3.92	$ 3.08	27	$ 3.28	$ 1.25	162
Average daily share trading volume (thousands)	3,419	3,290	4	3,773	2,888	31
Average daily production						
Light oil (bbls/d)	17,382	18,487	(6)	17,423	15,670	11
Heavy oil (bbls/d)	31,328	5,616	458	15,768	4,613	242
NGL (bbls/d)	4,241	3,899	9	3,888	3,408	14
Natural gas (mcf/d)	68,355	74,291	(8)	67,221	65,226	3
Total (boe/d)	64,344	40,384	59	48,283	34,562	40
Average sale prices						
Light oil ($/bbl)	103.37	88.59	17	115.47	78.64	47
Heavy oil, net of blending expense ($/bbl)	71.36	71.69	-	85.40	64.56	32
NGL ($/bbl)	50.53	55.09	(8)	54.66	41.77	31
Natural gas ($/mcf)	4.89	5.09	(4)	6.15	3.70	66
Total ($/boe)	71.19	65.21	9	82.54	55.38	49
Operating netback ($/Boe)						
Average realized sales, net of blending expense	71.19	65.21	9	82.54	55.38	49
Royalty expenses	(15.07)	(9.50)	59	(16.01)	(8.10)	98
Net production and transportation expenses(1)	(14.19)	(10.84)	31	(13.23)	(10.77)	23
Operating field netback ($/Boe)(1)	41.93	44.87	(7)	53.30	36.51	46
Realized commodity hedging gain (loss)	0.31	(8.25)	(104)	(3.52)	(6.40)	(45)
Operating netback ($/Boe)(1)	42.24	36.62	15	49.78	30.11	65
Adjusted funds flow ($/Boe)(1)	33.24	33.40	-	41.26	26.97	53

Reserves Snapshot by Category

	PDP	TP	TPP
Total Reserves (mboe)(5)	75,744	135,066	242,191
Reserves Added (mboe)(6)	37,077	48,556	77,882
Reserves Replacement	210 %	276 %	442 %
NPV10 Before Tax ($mm)	$1,842	$2,852	$4,975

Year-Over-Year Reserves Data (Forecast Prices and Costs)

(mboe)	December 31, 2022[5]	December 31, 2021[5]	% Change
PDP	75,744	56,290	35 %
TP	135,066	104,133	30 %
TPP	242,191	181,932	33 %

2023 Outlook

Our 2023 production and capital guidance remains unchanged with target production of 68,000-72,000 boe/d[7] through and development expenditures expected to range from $425 to $475 million for the year. The 2023 budget is focused o long term sustainable free funds flow[1] across our portfolio of highly economic assets in the Charlie Lake, Clearwater a enhanced oil recovery projects to enhance return of capital to shareholders. The following table summarizes our 2023 a guidance[7].

Capital Budget ($mm)[3]	$425 - $475
Annual Average Production (boe/d)[7]	68,000 - 72,000
Average Oil & NGL Weighting	81% - 83%
Expenses:	
Royalty Rate (%)	19% - 21%
Operating ($/boe)	$9.00 - $9.50
Transportation ($/boe)[8]	$3.50 - $4.00
General and Administrative ($/boe)[9]	$1.25 - $1.35
Interest ($/boe)	$3.80 - $4.00
Taxes (%)	10% - 12%
Leasing Expenditures ($mm)	$3.5 - $4.5

Operations Update

Clearwater

Nipisi: Tamarack has rig released two oil wells and one multi-lateral injector to date in 2023 and expects to run a two-ri West Nipisi through to break up. By the end of Q1 2023, Tamarack will have commenced injection into eight new West This injection program builds on the strong waterflood pilot results at 102/13-19-076-07W5. The producing well in the p supported by three single-leg injectors, has delivered over 140 mbbls of cumulative oil production in 14 months and is c producing over 400 bopd with 15% water cut.

Nipisi development for 2023 will focus on continued waterflood expansion across the field. Multilateral injection wells ar reach waterflood patterns are being implemented to enhance waterflood capital efficiencies. Production for the first thre February averaged 12,500 boe/d(10) and construction of the second phase of Tamarack's Nipisi gas conservation proje expected to be complete by the end of the first quarter.? Upon completion Tamarack anticipates having over 90% of its solution gas conserved. In support of ongoing development, expansion of Tamarack's 15-22-076-07W5 oil battery will c in Q2 2023 with completion expected in Q4 2023. Volumes from this battery will be connected to a third-party pipeline w Tamarack holds an agreement for firm service. Once the battery is operational ~70% of Tamarack's Nipisi oil productio shipped via pipeline.

West Marten: The Company recently brought three new extended reach wells on stream at its 15-15-076-05W5 locatio wells were drilled under Tamarack's West Nipisi waterflood design. The wells continue to clean up, but recent productio over 700 bopd from the pad. Tamarack has one drilling rig running in West Marten at the 11-10-076-05W5 pad with thr rig released to date, and another six planned wells before breakup. The first two wells from the 11-10 pad site are expe commence production in the first half of March. West Marten production rates have averaged 1,900 boed/d(11) for the fi weeks of February and are expected to continue to climb as existing wells are optimized and new wells are brought on Tamarack is currently evaluating gas conservation in West Marten and will provide further updates throughout the year

Marten Hills and Canal: Production from Marten Hills and Canal averaged approximately 16,300 boe/d(12) over the first of February, up from approximately 15,100 boe/d(12) at the close of the acquisition. Tamarack has two drilling rigs activ Hills, which are expected to remain active until spring break-up, with eight wells rig released year-to-date in 2023. Two wells are currently recovering load fluid and three additional wells are expected to start recovering load fluid in the first March. Tamarack continues to evaluate waterflood in Marten Hills with additional pilots planned for later in 2023.

Southern Clearwater: Tamarack has rig released two wells year-to-date in Southern Clearwater and anticipates further commence in the second half of 2023. Its newly drilled 07-21-063-26W4 Jarvie well is on production and exceeding exp with an average production rate of 220 bopd over the first nine days. This is the first extended reach multi-lateral Tama drilled in Southern Clearwater. These promising results are expected to further extend the eastern boundaries of the Ja Tamarack also remains encouraged by results in Perryvale, with the 09-03-064-23W4 pad site exceeding 950 bopd fro wells, five of which have been on production for over four months, after an expansion and debottlenecking project was

Charlie Lake

In the Charlie Lake, Tamarack brought on three wells during Q4 2022. The 1-24-072-09W6 well continues to exceed ex and ranks as one of the top performing oil wells drilled in the play to-date. Based on field estimates, month-to-date in F 1-24 well averaged over 1,900 boe/d(13).

Tamarack currently has three drilling rigs active in the area and three wells are completed, awaiting final tie-in. Two dril expected to remain active until late Q2 2023. Tamarack is advancing to the construction phase of the Wembley Gas Pl track to be onstream at the end of Q2 2023. Current production on this asset is approximately 16,900 boe/d(14).

Exploration/Delineation Update

Enhancing the underlying profitability of our inventory is key to free funds flow growth and a critical component of our st five-year plan,. The Company had an active 2022 program and continues to move the program forward in 2023.

Clearwater

Peavine/Seal - Tamarack drilled its first multi-lateral well in Peavine, the results of which came in below expectations at approximately 40 bopd. Further appraisal of the area is planned for the second half of 2023 and 2024. At Seal, Tamara released three wells targeting three separate Clearwater equivalent sands. Testing of this three well pad is expected to by the end of the first quarter.

West Marten Hills Exploration - In 2022, Tamarack drilled a Clearwater C step-out well at 102/13-13-076-05W5. With in over 200 bopd, this well, along with competitor activity, has delineated over 20 sections of Clearwater C potential. Furth has provided the opportunity to optimize pad development by drilling both Clearwater C and Clearwater B sands from s utilizing shared infrastructure and improving capital efficiencies.

West Nipisi - Delineation of Clearwater C and Clearwater B potential continues with partner wells at 09-05-077-09W5 (

04-35-076-9W5 (B). Initial rates from the 04-35 well exceeded expectations with February month-to-date field estimates
bopd. The 09-05 well is currently cleaning up. These positive results continue to expand the Clearwater potential westw

Board of Directors Changes

Tamarack is pleased to announce the appointment of Ms. Caralyn Bennett to the Board of Directors, effective March 1, Bennett is Executive Vice President and Chief Strategy Officer of GLJ Ltd., while also serving as President of the Cana Oil Association and as a director of Acceleware Ltd. Caralyn brings strong advisory experience in reserves and resourc governance and contributes strategic expertise to business transformation including sustainability, decarbonization and diversification. She has a Professional Engineer designation with an Honours B.A.Sc. in Geological Engineering from th of Waterloo and actively volunteers her strategic and advisory expertise to a variety of energy development and educat organizations in Alberta and Ontario.

Risk Management

The Company takes a systematic approach to manage commodity price risk and volatility to ensure sustaining capital, servicing requirements and the base dividend are protected through a prudent hedging management program. For 202 approximately ~50% of net after royalty oil production is hedged against WTI with an average floor price of greater thar Our strategy provides downside protection while maximizing upside exposure. Additional details of the current hedges i be found in the corporate presentation on the Company website (www.tamarackvalley.ca).

We would like to thank our employees, shareholders and other stakeholders for all of their support over the past year. 2 another transformative year for Tamarack and it would not have happened without the dedication and hard work of our as well as the support from our Board of Directors. We look forward to the continued development of our high-quality as the creation of shareholder value in a sustainable and responsible way.

Investor Call Tomorrow

9:00 AM MDT (11:00 AM EDT)

Tamarack will host a webcast at 9:00 AM MDT (11:00 AM EDT) on Thursday, March 2, 2023 to discuss the year-end reserves, financial results and an operational update. Participants can access the live webcast via this link or through links provided on the Company's website. A recorded archive of the webcast will be available on the Company's website following the live webcast.

2022 Independent Qualified Reserve Evaluation

The following tables highlight the findings of the Reserve Report, which has been prepared in accordance with definitio standards and procedures contained in National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities 51-101") and the most recent publication of the Canadian Oil and Gas Evaluation Handbook (COGEH). All evaluations summaries of future net revenue are stated prior to the provision for interest, debt service charges or general and admi expenses and after deduction of royalties, operating costs, estimated well abandonment and reclamation costs and est future capital expenditures. The information included in the "Net Present Values of Future Net Revenue Before Income Discounted" table below is based on an average of pricing assumptions prepared by the following three independent ex reserves evaluators: GLJ, Sproule Associates Limited and McDaniel & Associates Consultants Ltd (the "3-Consultant A Forecast Pricing"). It should not be assumed that the estimates of future net revenues presented in the tables below rep fair market value of the reserves. All per share reserves metrics below are based on basic shares outstanding as of De 2022.

Company Reserves Data (Forecast Prices and Costs)

Reserves Category	Crude Oil Lt. & Med. Gross[15] (MBbl)	Crude Oil Lt. & Med. Net[15] (MBbl)	Crude Oil Heavy Gross (MBbl)	Crude Oil Heavy Net (MBbl)	Conven-tional Natural Gas Gross (MMcf)[16]	Conven-tional Natural Gas Net (MMcf)[16]	Natural Gas Liquids Gross (MBbl)	Natural Gas Liquids Net (MBbl)	Total Gross (MBoe)	Total Net (Mboe)
Proved:										
Developed Producing	25,098	19,787	24,266	19,691	115,876	104,129	7,069	5,691	75,744	62,524
Developed Non-Producing	797	730	1,313	1,100	3,686	3,282	109	80	2,834	2,458
Undeveloped	23,246	18,893	18,557	15,976	64,100	57,446	4,001	3,260	56,488	47,703
Total Proved	49,141	39,410	44,136	36,767	183,662	164,856	11,179	9,031	135,066	112,684
Probable	38,169	29,472	39,035	31,901	130,545	115,291	8,164	6,419	107,126	87,007
Total Proved plus Probable[17]	87,310	68,881	83,171	68,669	314,208	280,148	19,343	15,450	242,191	199,692

Net Present Values of Future Net Revenue before Income Taxes Discounted at (% per year)[18]

Reserves Category	0 %($000)	5 %($000)	10 %($000)	15 %($000)	20 %($000)	Unit Value Before Tax Discounted at 10%/Year[19] ($/Boe)	Unit Value Before Tax Discounted at 10%/Year[19] ($/Mcfe)
Proved:							
Developed Producing	2,267,461	2,029,788	1,841,795	1,691,893	1,570,059	29.46	4.91
Developed Non-Producing	103,748	87,279	75,539	66,845	60,175	30.73	5.12
Undeveloped	1,567,147	1,193,320	934,776	749,710	612,823	19.60	3.27
Total Proved	3,938,356	3,310,386	2,852,110	2,508,448	2,243,058	25.31	4.22
Probable	3,837,607	2,770,033	2,123,058	1,698,794	1,402,842	24.40	4.07
Total Proved plus Probable[17]	7,775,962	6,080,420	4,975,168	4,207,241	3,645,900	24.91	4.15

Reconciliation of Company Gross Reserves Based on Forecast Prices and Costs[5]

	Total Proved (Mboe)	Total Probable (Mboe)	Total Proved + Probable (Mboe)
December 31, 2021	104,133	77,799	181,932
Discoveries	0	0	0
Extensions & Improved Recovery[20]	14,783	7,675	22,459
Technical Revisions	994	(8,813)	(7,819)
Acquisitions	36,199	33,241	69,440
Dispositions	(5,659)	(3,367)	(9,026)
Economic Factors	2,240	590	2,830
Production	(17,623)	0	(17,623)
December 31, 2022[17]	135,066	107,126	242,191

Future Development Capital Costs[21]

The following is a summary of GLJ's estimated FDC required to bring TP and TPP undeveloped reserves on production.

Year	Total Proved Reserves ($000)	Total Proved Plus Probable Reserves ($000)
2023	243,873	342,424
2024	325,320	449,859
2025	235,577	397,175
2026 and Subsequent	193,615	397,952
Total	998,385	1,587,410
10% Discounted	832,446	1,300,876

Finding, Development & Acquisition Costs

	2022		Three-Year Average	
(amounts in $000s except as noted)	TP	TPP	TP	TPP
FD&A costs, including FDC[21][22]				
Exploration and development capital expenditures [23][24][25]	389,120	389,120	227,941	227,941
Acquisitions, net of dispositions[26]	1,758,182	1,758,182	860,224	860,224
Total change in FDC	374,870	621,784	199,945	294,887
Total FD&A capital, including change in FDC[17]	2,522,172	2,769,086	1,288,110	1,383,051
Reserve additions, including revisions - Mboe[5]	18,017	17,470	10,525	8,937
Acquisitions, net of dispositions - Mboe[5]	30,539	60,413	27,968	50,683
Total FD&A Reserves[17]	48,556	77,883	38,493	59,620
F&D costs, including FDC - $/boe	51.94	35.55	33.46	23.20
Acquisition costs, net of dispositions - $/boe	31.59	37.05	24.43	27.25
FD&A costs, including FDC - $/boe	63.95	35.12	36.86	22.48

About Tamarack Valley Energy Ltd.

Tamarack is an oil and gas exploration and production company committed to creating long-term value for its shareholders through sustainable free funds flow generation, financial stability and the return of capital. The Company has an extensive inventory of low-risk, oil development drilling locations focused primarily on Charlie Lake, Clearwater and EOR plays in Alberta. Operating as a responsible corporate citizen is a key focus to ensure we deliver on our environmental, social and governance (ESG) commitments and goals. For more information, please visit the Company's website at www.tamarackvalley.ca.

Abbreviations

AECO	the natural gas storage facility located at Suffield, Alberta connected to TC Energy's Alberta System
ARO	asset retirement obligation; may also be referred to as decommissioning obligation
bbls	barrels
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
bopd	barrels of oil per day
GJ	gigajoule
IFRS	International Financial Reporting Standards as issued by the International Accounting Standards Board
IP30	average production for the first 30 days that a well is onstream
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
MM	Million
mmcf/d	million cubic feet per day
MSW	Mixed sweet blend, the benchmark for conventionally produced light sweet crude oil in Western Canada
NGL	Natural gas liquids
PDP	Proved developed producing reserves
TP	Total proved reserves
TPP	Total proved plus probable reserves
WCS	Western Canadian select, the benchmark for conventional and oil sands heavy production at Hardisty in Western Canada
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade

Reader Advisories

Notes to Press Release

(1) See "Specified Financial Measures"

(2) Q4 2022 production guidance of 62,000-64,000 boe/d was comprised of 16,500-17,500 bbl/d light and medium oil, 35,000-37,000 bbl/d heavy oil, 3,500-4,500 bbl/d NGL and 73,000-78,000 mcf/d natural gas.

Q4 2022 production of 64,344 boe/d was comprised of 17,382 bbl/d light and medium oil, 31,328 bbl/d heavy oil, 4,241 bbl/d NGL and 68,355 mcf/d natural gas.

2022 yearly production of 48,283 boe/d was comprised of 17,423 bbl/d light and medium oil, 15,768 bbl/d heavy oil, 3,888 bbl/d NGL and 67,221 mcf/d natural gas.

(3) Capital expenditures include exploration and development capital, ESG initiatives, facilities land and seismic but exclude asset acquisitions and dispositions as well as ARO. Capital budget includes exploration and development capital, ARO, ESG initiatives, facilities land and seismic but excludes asset acquisitions and dispositions. The key difference between these two metrics is the inclusion (capital budget) or exclusion (capital expenditures) of ARO.

(4) Realized before-tax net present value of reserve, discounted at 10%

(5) Reserves are Company Gross Reserves which exclude royalty volumes

(6) Reserves Added takes the difference in reserves year-over-year plus the production for the year

(7) Target production is comprised of 16,500-17,500 bbl/d light and medium oil, 35,000-37,000 bbl/d heavy oil, 3,500-4,500 bbl/d NGL and 73,000-78,000 mcf/d natural gas. Annual guidance numbers are based on 2023 average pricing assumptions of: US$80.00/bbl WTI; US$22.00/bbl WCS; US$3.00/bbl MSW; $4.00/GJ AECO; and $1.3200 CAD/USD.

(8) Transportation expense differs from the previously released 2023 guidance due to a change in the classification of pipeline tariffs in our corporate model. Some pipeline tariffs were originally included as a revenue deduction, are now included as transportation expense.

(9) G&A noted excludes the effect of cash settled stock-based compensation

(10) Production of 12,500 boe/d is comprised of approximately 11,800 bbl/d heavy oil, 100 bbl/d NGL and 3,600 mcf/d natural gas

(11) Production of 1,900 boe/d is comprised of approximately 1,900 bbl/d heavy oil

(12) Current production of 16,300 boe/d is comprised of approximately 15,390 bbl/d heavy oil, 110 bbl/d NGL and 4,800 mcf/d natural gas while production at acquisition of 15,100 boe/d is comprised of approximately 14,260 bbl/d heavy oil, 90 bbl/d NGL and 4,500 mcf/d natural gas

(13) Production of 1,900 boe/d is comprised of approximately 1,200 bbl/d light and medium oil, 125 bbl/d NGL and 3,450 mcf/d natural gas

(14) Production of 16,900 boe/d is comprised of approximately 9,600 bbl/d light and medium oil, 2,300 bbl/d NGL and 30,000 mcf/d natural gas

(15) Tight oil included in the light & medium crude oil product type represents less than 6.5% of any reserves category

(16) Conventional natural gas amounts include coal bed methane, in amounts less than 0.3% of any reserves category

(17) Columns may not add due to rounding

(18) Unit values based on Company net interest reserves

(19) The prices used to estimate net present values are based on the 3-Consultant Average Forecast Pricing

(20) Reserves additions under Infill Drilling, Improved Recovery and Extensions are combined and reported as "Extensions and Improved Recovery"

(21) FDC as per Reserve Report based on the 3-Consultant Average Forecast Pricing

(22) While NI 51-101 requires that the effects of acquisitions and dispositions be excluded from the calculation of finding and development costs, FD&A costs have been presented because acquisitions and dispositions can have a significant impact on the Company's ongoing reserve replacement costs and excluding these amounts could result in an inaccurate portrayal of the Company's cost structure. Finding and development costs both including and excluding acquisitions and dispositions have been presented above.

(23) The calculation of FD&A costs incorporates the change in FDC required to bring proved undeveloped and developed reserves into production. In all cases, the FD&A number is calculated by dividing the identified capital expenditures by the applicable reserves additions after changes in FDC costs.

(24) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

(25)

The capital expenditures also exclude capitalized administration costs.

(26) Includes capital spent in 2022 to develop the assets acquired during 2022 as well as major land acquisitions in the Peavine and Seal areas.

Disclosure of Oil and Gas Information

Unit Cost Calculation. For the purpose of calculating unit costs, natural gas volumes have been converted to a boe using six thousand cubic feet equal to one barrel unless otherwise stated. A boe conversion ratio of 6:1 is based upon an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion conforms with Canadian Securities Administrators' National Instrument 51 101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Boe may be misleading, particularly if used in isolation.

References in this press release to "crude oil" or "oil" refers to light, medium and heavy crude oil product types as defined by NI 51-101. References to "NGL" throughout this press release comprise pentane, butane, propane, and ethane, being all NGL as defined by NI 51-101. References to "natural gas" throughout this press release refers to conventional natural gas as defined by NI 51-101.

Forward Looking Information

This press release contains certain forward-looking information (collectively referred to herein as "forward-looking statements") within the meaning of applicable Canadian securities laws. Forward-looking statements are often, but not always, identified by the use of words such as "guidance", "outlook", "anticipate", "target", "plan", "continue", "intend", "consider", "estimate", "expect", "may", "will", "should", "could" or similar words suggesting future outcomes. More particularly, this press release contains statements concerning: Tamarack's business strategy, objectives, strength and focus; future consolidation activity, organic growth and development and portfolio rationalization; future intentions with respect to return of capital, including enhanced dividends and share buybacks; oil and natural gas production levels, adjusted funds flow and free funds flow; anticipated operational results for 2023 including, but not limited to, estimated or anticipated production levels, capital expenditures, drilling plans and infrastructure initiatives; the Company's capital program, guidance and budget for 2023 and 2023 capital program and the funding thereof; expectations regarding commodity prices; the performance characteristics of the Company's oil and natural gas properties; decline rates and enhanced recovery, including waterflood initiatives; exploration activities; successful integration of the Deltastream assets; the ability of the Company to achieve drilling success consistent with management's expectations; risk management activities, Tamarack's commitment to ESG principles and sustainability; and the source of funding for the Company's activities including development costs. Future dividend payments and share buybacks, if any, and the level thereof, are uncertain, as the Company's return of capital framework and the funds available for such activities from time to time is dependent upon, among other things, 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 and buyback shares 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. 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.

The forward-looking statements contained in this document are based on certain key expectations and assumptions made by Tamarack, including those relating to: the business plan of Tamarack; the timing of and success of future drilling, development and completion activities; the geological characteristics of Tamarack's properties; the characteristics of recently acquired assets, including the Deltastream assets; the successful integration of recently acquired assets into Tamarack's operations; prevailing commodity prices, price volatility, price differentials and the actual prices received for the Company's products; the availability and performance of drilling rigs, facilities, pipelines and other oilfield services; the timing of past operations and activities in the planned areas of focus; the drilling, completion and tie-in of wells being completed as planned; the performance of new and existing wells; the application of existing drilling and fracturing techniques; prevailing weather and break-up conditions; royalty regimes and exchange rates; impact of inflation on costs; the application of regulatory and licensing requirements; the continued availability of capital and skilled personnel; the ability to maintain or grow the banking facilities; the accuracy of Tamarack's geological interpretation of its drilling and land opportunities, including the ability of seismic activity to enhance such interpretation; and Tamarack's ability to execute its plans and strategies.

Although management considers these assumptions to be reasonable based on information currently available, undue reliance should not be placed on the forward-looking statements because Tamarack can give no assurances that they may prove to be correct. By their very nature, forward-looking statements are subject to certain risks and uncertainties (both general and specific) that could cause actual events or outcomes to differ materially from those anticipated or implied by such forward-looking statements. These risks and uncertainties include, but are not limited to: the risk that future dividend payments thereunder are reduced, suspended or cancelled; unforeseen difficulties in integrating of recently acquired assets into Tamarack's operations, including the Deltastream assets; incorrect assessments of the value of benefits to be obtained from acquisitions and exploration and development programs; risks associated with the oil and gas industry in general (e.g. operational risks in development, exploration and production; and delays or changes in plans with respect to exploration or development projects or capital expenditures); commodity prices; the uncertainty of estimates and projections relating to production, cash generation, costs and expenses, including increased operating and capital costs due to inflationary pressures; health, safety, litigation and environmental risks; access to capital; the COVID-19 pandemic; and Russia's military actions in Ukraine. Due to the nature of the oil and natural gas industry, drilling plans and operational activities may be delayed or modified to respond to market conditions, results of past operations, regulatory approvals or availability of services causing results to be delayed. Please refer to the Company's AIF and the management discussion and analysis for the period ended December 31, 2022 (the "MD&A") for additional risk factors relating to Tamarack, which can be accessed either on Tamarack's website at www.tamarackvalley.ca or under the Company's profile on www.sedar.com.The forward-looking statements contained in this press release are made as of the date hereof and the Company does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, except as required by applicable law. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

This press release contains future-oriented financial information and financial outlook information (collectively, "FOFI") about generating sustainable long-term growth in free funds flow, dividends and share buybacks, prospective results of operations and production, weightings, operating costs, 2023 capital budget and expenditures, decline rates, balance sheet strength, adjusted funds flow and free funds flow, net debt, debt repayments, total returns and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs. FOFI contained in this document was approved by management as of the date of this document and was provided for the purpose of providing further information about Tamarack's future business operations. Tamarack and its management believe that FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments, and represent, to the best of management's knowledge and opinion, the Company's expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future results. Tamarack disclaims any intention or obligation to update or revise any FOFI contained in this document, 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 document should not be used for purposes other than for which it is disclosed herein. Changes in forecast commodity prices, differences in the timing of capital expenditures, and variances in average production estimates can have a significant impact on the key performance measures included in Tamarack's guidance. The Company's actual results may differ materially from these estimates.

Specified Financial Measures

This press release includes various specified financial measures, including non-IFRS financial measures, non-IFRS financial ratios and capital management measures as further described herein. These measures do not have a standardized meaning prescribed by International Financial Reporting Standards ("IFRS") and, therefore, may not be comparable with the calculation of similar measures by other companies.

"Adjusted funds flow (capital management measure)" is calculated by taking cash-flow from operating activities, on a periodic basis, deducting current income taxes and adding back changes in non-cash working capital, expenditures on decommissioning obligations and transaction costs since Tamarack believes the timing of collection, payment or incurrence of these items is variable. While current income taxes will not be paid until Q1/23, management believes adjusting for estimated current income taxes in the period incurred is a better indication of the adjusted funds generated by the Company. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of the Company's operating areas. Expenditures on decommissioning obligations are managed through the capital budgeting process which considers available adjusted funds flow. Tamarack uses adjusted funds flow as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. Adjusted funds flow per share is calculated using the same weighted average basic and diluted shares that are used in calculating income per share. Adjusted funds flow can also be calculated on a per boe basis, which results in the measure being considered a non-IFRS financial ratio.

"Free funds flow (previously referred to as "free adjusted funds flow") and Capital Expenditures (capital management measure)". Fee funds flow is calculated by taking adjusted funds flow and subtracting capital expenditures, excluding acquisitions and dispositions. Capital expenditure is calculated as property, plant and equipment additions (net of government assistance) plus exploration and evaluation additions. Management believes that free funds flow provides a useful measure to determine Tamarack's ability to improve returns and to manage the long-term value of the business.

"Net Production Expenses, Revenue, net of blending expense, Operating Netback and Operating Field Netback (Non-IFRS Financial Measures, and Non-IFRS Financial Ratios if calculated on a per boe basis)" Management uses certain industry benchmarks, such as net production expenses, revenue, net of blending expense, operating netback and operating field netback, to analyze financial and operating performance. Net production expenses are determined by deducting processing income primarily generated by processing third party volumes at processing facilities where the Company has an ownership interest. Under IFRS this source of funds is required to be reported as revenue. Blending expense includes the cost of blending diluent to reduce the viscosity of our heavy oil transported through pipelines to meet pipeline specifications and is shown as a reduction to heavy oil revenues rather than an expense as in the financial statements under IFRS. Operating netback equals total petroleum and natural gas sales (net of blending), including realized gains and losses on commodity and foreign exchange derivative contracts, less royalties, net production expenses and transportation expense. Operating field netback equals total petroleum and natural gas sales, less royalties, net production expenses and transportation expense. These metrics can also be calculated on a per boe basis, which results in them being considered a non-IFRS financial ratio. Management considers operating netback and operating field netback important measures to evaluate Tamarack's operational performance, as it demonstrates field level profitability relative to current commodity prices. See the MD&A for a detailed calculation and reconciliation of Tamarack's netbacks per boe to the most directly comparable measure presented in accordance with IFRS.

"Net debt (capital management measure)" is calculated as credit facilities plus senior unsecured notes, plus deferred acquisition payment notes, plus working capital surplus or deficiency, plus other liability, including the fair value of cross-currency swaps, plus government loans, plus facilities acquisition payments, less notes receivable and excluding the current portion of fair value of financial instruments, decommissioning obligations, lease liabilities and the cash award incentive plan liability.

"Net debt to quarterly annualized adjusted funds flow (capital management measure)" is calculated as estimated period end net debt divided by the annualized adjusted funds flow for the preceding quarter (multiplied by 4 for annualization).

SOURCE Tamarack Valley Energy Ltd.

Contact

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