TSX: TVE

Tamarack Valley Energy Ltd. Announces 2019 Financial Results, Reserves Information and Appointment of Chief Financial Officer

Calgary, Alberta – March 5, 2020 – Tamarack Valley Energy Ltd. ("**Tamarack**" or the "**Company**") is pleased to announce its financial and operating results for the three months and year ended December 31, 2019 and the results of its independent oil and gas reserves evaluation as of December 31, 2019, prepared by GLJ Petroleum Consultants Ltd. ("GLJ") (the "GLJ Report"). Selected financial, operational and reserves information is outlined below and should be read with Tamarack's audited consolidated financial statements ("Financial Statements") and management's discussion and analysis ("MD&A") as of December 31, 2019, which are available on SEDAR at www.sedar.com and on Tamarack's website at www.tamarackvalley.ca. The Company's annual information form ("AIF") for the year ended December 31, 2019 has also been filed on SEDAR effective today and is available on Tamarack's website.

2019 Financial and Operating Highlights

- Achieved stable quarterly production volumes of 24,859 boe/d in Q4/19, slightly higher than the Q4/18 average of 24,780 boe/d and 3% higher than the previous quarter, and annual volumes of 24,072 boe/d, while generating free adjusted funds flow (see "Non-IFRS Measures") of $40.5 million in 2019.
- Generated adjusted funds flow (previously referred to as "adjusted operating field netback"; see "Non-IFRS Measures") of $219.4 million in 2019 ($0.97 per share basic and diluted), compared to $226.5 million in 2018 ($0.99 per share basic and $0.97 per share diluted). Q4/19 adjusted funds flow was $54.7 million, an increase of $16.4 million, or 43%, over the same period in 2018.
- Invested $179.0 million in capital expenditures, excluding acquisitions, during 2019 which contributed to the drilling of 149 (144.5 net) wells, comprised of 127 (124.1 net) Viking oil wells, 14 (12.5 net) Cardium oil wells, two (2.0 net) Penny Barons oil wells and six (5.9 net) water source and injector wells, as well as bringing wells drilled in Q4/18 onto production in 2019.
- Directed free adjusted funds flow to key projects such as tuck-in acquisitions and the Company's active share repurchase program which included: $8.3 million to purchase and cancel 4.2 million shares; and, $3.5 million to purchase an additional 1.6 million shares to be held in trust by Tamarack's trustee for future restricted share units ("RSUs") settlement, offsetting RSU dilution and supporting debt-adjusted per share metrics.
- Reduced net debt by 11% quarter-over-quarter to $189.5 million, including working capital deficiency but excluding the fair value of financial instruments and lease liabilities, resulting in a 2019 net debt to annualized adjusted funds flow ratio (see "Non-IFRS Measures") of 0.9 times.
- Held Tamarack's oil and natural gas liquids ("NGL") weighting stable at 63% year-over-year, while spending $30.3 million less in capital, after acquisitions and dispositions, with an 8% increase in incremental oil production over Q3 and increasing waterflood production.
- Generated higher operating netbacks (see "Non-IFRS Measures") in Q4/19 relative to Q4/18 and Q3/19 due in part to Tamarack's ongoing focus on cost controls, while slightly lower annual operating netbacks in 2019 compared to 2018 reflects the impact of lower natural gas prices, offset by reductions in net production and transportation expenses stemming primarily from increased production from the lower-cost Veteran area.

- Managed key environmental, social and governance goals in the business during 2019 through project specific improvements, including: exclusion of fresh water use in Viking completion and waterflood operations; accelerated abandonment and reclamation programs; lower land usage per well through multi-well pad drilling; and ongoing relationship management with indigenous communities in the Company's operating areas.

2019 Reserve Highlights

Tamarack is pleased to provide select highlights of the Company's proved developed producing ("PDP"), total proved ("TP") and total proved plus probable ("TPP") reserves from the GLJ Report below. Finding, development and acquisition ("FD&A") costs (see "Oil and Gas Metrics") and finding and development ("F&D") costs (see "Oil and Gas Metrics") contained within this release include changes in future development capital ("FDC"). The ongoing positive impact of Tamarack's Veteran waterflood program contributed significantly to the reserves in 2019 and set the stage for further development in 2020 and beyond. The waterflood program also adds value to the overall corporate strategy, which is designed to lower corporate decline rates, increase the Company's overall oil weighting and enhance Tamarack's capital efficiencies.

- Recognized meaningful contribution from Tamarack's Veteran waterflood program in 2019, with changes in the Company's oil reserves due specifically to waterflood reflecting increases of 5% on a PDP basis, 14% on TP, and 6% on TPP relative to 2018, which are conservative relative to internal estimates.
- Demonstrated success in converting proved undeveloped reserves to PDP reserves, with PDP reserves increasing by 8% to 34.4 million boe ("mmboe"), TP reserves up 4% to 57.9 mmboe and TPP reserves maintained at 101.6 mmboe relative to 2018.
- Realized growth of 10% on PDP, 6% on TP and 2% on TPP on a basic per share basis, demonstrating the combined benefit of adding new reserves coupled with the Company's ongoing share buybacks to drive enhanced per share metrics.
- Realized waterflood benefits earlier than the Company previously anticipated. Tamarack's 2019 corporate decline rate was 38%, compared to 41% in 2018, with further expected improvements as a result of ongoing waterflood development to 34% in 2020 and less than 30% in 2021, based on internal forecasts.
- Increased oil rate responses to water injection in Veteran waterflood projects provided the confidence to add limited PDP reserves and substantial TP reserves over previously booked TPP projects. Both PDP and TP categories grew from nil reserves to 0.9 mmbbls and 4.3 mmbbls respectively. New reserves were also added through extensions of waterflood patterns to increase TPP bookings to 8.9 mmbbls.
- Increased the overall crude oil weighting of Tamarack's reserves to 57% and 59% for TP and TPP, respectively, compared to 55% and 58% for the respective categories in 2018, driving the Company's combined TP oil and NGL weighting to approximately 65% of total TP reserves in 2019 from 63% in 2018.
- Generated improved capital efficiencies relative to 2018 across a growing PDP and TP reserves base, reporting 37% lower PDP F&D costs of $16.14/boe with a recycle ratio (see "Oil and Gas Metrics") of 1.8x; and 11% lower TP F&D costs of $18.10/boe with a recycle ratio of 1.6x, based on the 2019 average operating field netback of $28.89/boe excluding hedges. Higher TPP F&D of $20.97/boe with a 1.4x recycle ratio reflects the stable nature of TPP reserves year-over-year as proved undeveloped ("PUD") conversions into producing categories were the predominant contributor to the reserves changes in 2019.
- Replaced 130% of production on a PDP basis, 125% on a TP basis and 101% on a TPP basis with PDP reserves representing 59% of TP, and TP representing 57% of TPP.

- Achieved net asset values of $1.71, $2.97 and $5.76 per basic share for PDP, TP and TPP reserves respectively, based on before tax net present values (discounted at 10%). The net present value of reserves has been adjusted for net debt of $189.5 million but assumes no value for undeveloped land or infrastructure.
- Achieved a TPP reserve life index ("RLI") of 11.6 years and a TP RLI of 6.6 years, based on 2019 average production of 24,072 boe/d.

Appointment of Chief Financial Officer

Tamarack is pleased to announce that Mr. Steve Buytels will be joining the Company as Vice President, Finance & Chief Financial Officer. Mr. Buytels brings over 13 years of oil and gas capital markets, finance and advisory industry experience. He most recently served as Managing Director and Co-Head of Institutional Energy Equities at Stifel FirstEnergy where he was responsible for E&P, oilfield service and infrastructure related capital markets advisory as well as debt and equity financing. Prior to, Mr. Buytels served as principal at Peters & Co in the Institutional Equities group and Head of Energy at an independent investment bank, with offices in Toronto, Montreal and London, and was responsible for the buildout of their institutional energy business. Mr. Buytels holds a Chartered Financial Analyst Designation and a Bachelors of Management from the University of Lethbridge. The Company is pleased to welcome Steve to the Tamarack team.

Financial & Operating Results

	Three months ended December 31,			Years ended December 31,		
	2019	2018 [3]	% change	**2019**	2018 [3]	% change
($ thousands, except per share)						
Total oil, natural gas and processing revenue	**98,130**	73,501	34	**382,816**	399,462	(4)
Adjusted funds flow [1]	**54,742**	38,346	43	**219,434**	226,475	(3)
Per share – basic [1]	**$ 0.25**	$ 0.17	47	**$ 0.97**	$ 0.99	(2)
Per share – diluted [1]	**$ 0.25**	$ 0.17	47	**$ 0.97**	$ 0.97	–
Net income (loss)	**(50,546)**	18,952	(367)	**(39,011)**	38,310	(202)
Per share – basic	**$ (0.23)**	$ 0.08	(388)	**$ (0.17)**	$ 0.17	(200)
Per share – diluted	**$ (0.23)**	$ 0.08	(388)	**$ (0.17)**	$ 0.16	(206)
Net debt [1]	**(189,481)**	(179,880)	5	**(189,481)**	(179,880)	5
Capital expenditures [2]	**22,954**	25,798	(11)	**178,966**	226,251	(21)
Weighted average shares outstanding *(thousands)*						
Basic	**223,305**	227,211	(2)	**225,219**	227,720	(1)
Diluted	**223,305**	232,066	(4)	**225,219**	233,561	(4)
Share Trading *(thousands, except share price)*						
High	**$ 2.05**	$ 5.20	(61)	**$ 3.09**	$ 5.20	(41)
Low	**$ 1.59**	$ 1.81	(12)	**$ 1.59**	$ 1.81	(12)
Trading volume (thousands)	**35,103**	72,410	(52)	**179,985**	268,916	(33)

	Three months ended December 31,			Years ended December 31,		
	2019	2018 [3]	% change	**2019**	2018 [3]	% change
Average daily production						
Light oil (bbls/d)	**13,729**	14,163	(3)	**13,103**	13,769	(5)
Heavy oil (bbls/d)	**318**	755	(58)	**440**	552	(20)
NGL (bbls/d)	**1,735**	1,485	17	**1,622**	1,398	16
Natural gas (mcf/d)	**54,462**	50,262	8	**53,444**	51,108	5
Total (boe/d)	**24,859**	24,780	–	**24,072**	24,237	(1)
Average sale prices						
Light oil ($/bbl)	**64.26**	36.78	75	**66.25**	64.17	3
Heavy oil ($/bbl)	**58.96**	49.33	20	**55.27**	59.13	(7)
NGL ($/bbl)	**21.96**	33.72	(35)	**25.57**	41.89	(39)
Natural gas ($/mcf)	**2.26**	3.70	(39)	**2.06**	2.30	(10)
Total ($/boe)	**42.72**	32.05	33	**43.37**	45.08	(4)
Operating netback ($/Boe) [1]						
Average realized sales	**42.72**	32.05	33	**43.37**	45.08	(4)
Royalty expenses	**(4.39)**	(2.59)	69	**(4.45)**	(4.51)	(1)
Net production and transportation expenses	**(9.96)**	(10.47)	(5)	**(10.03)**	(10.52)	(5)
Operating field netback ($/Boe) [1]	**28.37**	18.99	49	**28.89**	30.05	(4)
Realized commodity hedging (loss) gain	**(2.04)**	0.04	(5,200)	**(1.42)**	(2.03)	(30)
Operating netback	**26.33**	19.03	38	**27.47**	28.02	(2)
Adjusted funds flow ($/Boe) [1]	**23.94**	16.82	42	**24.97**	25.60	(2)

Notes:

(1) Net debt, operating netback, operating field netback and adjusted funds flow do not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. See "*Non-IFRS Measures*".

(2) Capital expenditures include exploration and development expenditures but exclude asset acquisitions and dispositions.

(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated.

2019 Year in Review

Tamarack continued to demonstrate the strength of its differentiated strategy during 2019, generating free adjusted funds flow while maintaining a disciplined approach to allocating capital, reducing corporate declines and above all, enhancing per share metrics. The Company successfully executed each of these objectives in 2019, while effectively managing safe and efficient operations despite ongoing industry challenges.

Annual production volumes remained stable in 2019 at 24,072 boe/d (63% oil and NGL), despite continued uncertain market egress conditions and were in-line with the mid-point of the annual guidance range of 23,500 to 24,500 boe/d. In Q4/19, Tamarack invested $23.0 million in capital expenditures and achieved production of 24,859 boe/d (63% oil and NGL), 3% higher than the previous quarter, reflecting the impact of 11 net Viking oil wells coming on-stream that were drilled and awaiting completion at the end of Q3/19, plus 15 gross (14.6 net) Viking oil wells that were drilled and brought on-stream in Q4/19.

Tamarack's prudent 2019 capital expenditures reflected the broader commodity price and operating environment, as the Company invested 20% less capital relative to 2018. Tamarack has remained committed to drilling wells which are expected to payout in 1.5 years or less and estimates it has more than ten years of development within its current inventory. Annual capital of $179.0 million ($188.9 million, including acquisitions and dispositions) was fully funded by the Company's $219.4 million of adjusted funds flow generated during the period, and directed to the continued development of its high-quality, light oil-weighted asset base, accretive tuck-in acquisitions and ongoing advancement of the waterflood program. Tamarack drilled 149 (144.5 net) wells, comprised of 127 (124.1 net) Viking oil wells, 14 (12.5 net) Cardium oil wells, two (2.0 net) Penny oil wells and six (5.9 net) water source and injector wells.

Free adjusted funds flow of $40.5 million was used to fund tuck-in acquisitions, lease asset purchases, lease liabilities, abandonments and share repurchases. The Company completed six tuck-in acquisitions during the year totaling $9.9 million, adding 17.9 net sections of undeveloped Viking land adjacent to existing acreage in the Veteran/Consort area, 0.6 net sections in the Wilson Creek/Alder Flats area and approximately 800 boe/d of associated production, which contributed approximately 220 boe/d to Tamarack's annual average production. Tamarack's waterflood program at Veteran is designed to improve oil recoveries, reduce corporate decline rates and increase production rates while utilizing the Company's existing and owned infrastructure. Approximately $27 million was invested in the Veteran waterflood in 2019, which included the conversion of eight (7.7 net) Viking oil wells into water injectors and resulted in meaningful reserves increases as outlined below under "2019 Year-End Reserves Summary: Clear Waterflood Impact".

Consistent with the Company's commitment to generating per share value, Tamarack purchased and cancelled 4,181,100 outstanding shares under its normal course issuer bid ("NCIB") program, for a total investment of $8.3 million. The NCIB program provides management with an instrument that can be employed when there is a perceived misalignment between the Company's prevailing share price and the underlying current and future potential value of its assets. In addition to supporting the Company's commitment to generating per share value, the NCIB program also helps to offset the dilutive impact that may be associated with the exercise and settlement of options, RSUs and performance share units ("PSUs") issued under Tamarack's stock-based compensation programs. Over and above the NCIB program, in 2019, the Company purchased 1,639,764 common shares in the open market for $3.5 million which are held in trust by Tamarack's trustee and used to settle RSUs upon future exercises, mitigating dilution and further supporting Tamarack's per share metrics. At December 31, 2019, the remaining balance of purchased common shares held in trust totaled 469,120.

Tamarack remains focused on increasing its oil and NGL weighting; however, the impact of the production curtailment order imposed by the Government of Alberta, which became effective on January 1, 2019, led to a shift in the timing and nature of the Company's capital activities in 2019, which resulted in a stable average oil and NGL weighting of 63%. Given the commodity price volatility which prevailed through 2019, Tamarack's average per boe sales price decreased 4% year-over-year to $43.37/boe from $45.08/boe in 2018. In Q4/19, the Company's average realized sales price of $42.72/boe was higher than both Q3/19 and Q4/18. Operating netbacks in 2019 averaged $27.47/boe, 2% lower than in 2018, and in Q4/19 averaged $26.33/boe, 38% and 7% higher than in Q4/18 and Q3/19, respectively. Stronger operating netbacks were partially attributable to lower net production and transportation expenses, which improved by 5% in both Q4/19 and full year 2019 as compared to the same periods in 2018, primarily due to increased production from the lower cost Veteran area.

Tamarack's year end 2019 net debt, including working capital deficiency but excluding the fair value of financial instruments and lease liabilities, totaled $189.5 million, 11% lower than September 30, 2019. Tamarack's 2019 net debt to annualized adjusted funds flow ratio was 0.9 times.

2019 Year-End Reserves Summary: Clear Waterflood Impact

Tamarack's strategy to invest in long-term sustainability enhancement projects continued through 2019. The Company continued allocating capital to its Veteran waterflood program through the year, and as a result, has set the stage for ongoing waterflood development given the bulk of the required infrastructure spending was achieved in 2019. In addition to positive waterflood related reserve changes, Tamarack's waterflood program has improved corporate decline rates – from 41% in 2018 to 38% in 2019, with projected 2020 declines of 34%.

Further success is evidenced in the GLJ Report, which reflects year-end reserves attributable to waterflood projects of 0.9 mmboe for PDP, 4.3 mmboe for TP and 8.9 mmboe for TPP, compared to nil for each of PDP and TP, and 4.9 mmboe for TPP in 2018. These reserve assignments are limited to the Hamilton Lake zone only (approximately 45% of the combined Viking/Hamilton Lake average original oil in place) and include estimated incremental booked recovery factors in various patterns ranging from 6-11% on a TP basis to 12-23% on TPP. Tamarack's oil reserves across all categories increased meaningfully in 2019, attributable in part to the waterflood, with a 5.7% increase in PDP, 8.4% in TP, and 2.1% in TPP.

The Company maintained a consistent approach to reserves booking, with TP reserves including only 156.9 net Veteran and Consort horizontal Viking oil wells, 94.4 net Redwater and Saskatchewan horizontal Viking oil wells and 40.2 net undeveloped horizontal Cardium oil locations. The total FDC on a TP basis was $398.5 million and on a TPP basis was $702.7 million.

Tamarack recorded improved capital efficiencies relative to 2018 across a growing PDP and TP reserves base. The Company achieved 37% lower F&D costs of $16.14/boe with an F&D recycle ratio of 1.8 times based on the 2019 average operating field netback of $28.89/boe excluding hedges. TP F&D costs were 11% lower at $18.10/boe, achieving a recycle ratio of 1.6 times. Higher F&D of $20.97/boe with a 1.4 times recycle ratio reflects the stable nature of TPP reserves year-over-year as PUD conversions into PDP were the predominant contributor.

The following tables highlight the findings of the GLJ Report, which has been prepared in accordance with definitions, standards and procedures contained in *National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook. All evaluations and summaries of future net revenue are stated prior to provision for interest, debt service charges or general and administrative expenses and after deduction of royalties, operating costs, estimated well abandonment and reclamation costs and estimated future capital expenditures. The information included in the "Net Present Values of Future Net Revenue before Income Taxes" table below is based on an average of pricing assumptions prepared by three independent external reserves evaluators. It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. Given Tamarack's ongoing and extensive share buy-backs during 2019, all per share reserves metrics below are based on basic shares outstanding.

Reserves Snapshot by Category:

	PDP	TP	TPP
Reserves Added(1) (mboe)	11,422	11,022	8,846
Total Reserves (mboe)(2)	34,424	57,886	101,632
Reserves Replacement	34%	57%	-
NPV10 BT ($mm)	$571	$852	$1,476
FD&A Cost per boe(3)	$16.74	$18.68	$21.64
Recycle Ratio(4)	1.73x	1.55x	1.33x
F&D Cost per boe (3)	$16.14	$18.10	$20.97
Recycle Ratio(4)	1.79x	1.60x	1.38x

Notes:

(1) This number takes the difference in reserves year-over-year plus the production for the year.
(2) Total reserves are Company Gross Reserves which exclude royalty volumes.
(3) Including changes in FDC.
(4) Based on unhedged 2019 operating netback of $28.89 per boe.

Reserves Data (Forecast Prices and Costs) – Company Gross

RESERVES CATEGORY	CRUDE OIL[1] Gross (Mbbls)	CRUDE OIL[1] Net (Mbbls)	CONVENTIONAL NATURAL GAS[2] Gross (Mmcf)	CONVENTIONAL NATURAL GAS[2] Net (Mmcf)	NATURAL GAS LIQUIDS Gross (Mbbls)	NATURAL GAS LIQUIDS Net (Mbbls)	TOTAL OIL EQUIVALENT Gross (Mboe)	TOTAL OIL EQUIVALENT Net (Mboe)
PROVED:								
Developed Producing	17,425	15,359	82,976	76,043	3,170	2,616	34,424	30,649
Developed Non-Producing	2,007	1,446	2,805	2,560	39	35	2,513	1,908
Undeveloped	13,667	11,826	36,979	34,441	1,119	1,001	20,949	18,566
TOTAL PROVED	**33,098**	**28,631**	**122,759**	**113,044**	**4,328**	**3,651**	**57,886**	**51,123**
PROBABLE	27,303	22,910	82,223	75,838	2,739	2,326	43,746	37,876
TOTAL PROVED PLUS PROBABLE	**60,401**	**51,541**	**204,982**	**188,882**	**7,067**	**5,977**	**101,632**	**88,999**

Notes:
(1) Heavy oil and tight oil included in the crude oil product type represents less than 10.1% of any reserves category.
(2) Conventional natural gas amounts include coal bed methane, in amounts less than 0.2%.
(3) Columns may not add due to rounding.

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

RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	Unit Value Before Income Tax Discounted at 10% Per Year[1] ($/Boe)
PROVED:						
Developed Producing	768,457	651,261	570,656	511,351	465,628	18.62
Developed Non-Producing	80,674	65,601	55,226	47,547	41,611	28.95
Undeveloped	401,536	298,791	226,398	174,336	135,824	12.19
TOTAL PROVED	**1,250,666**	**1,015,654**	**852,280**	**733,234**	**643,063**	**16.67**
PROBABLE	1,273,554	860,135	624,135	477,074	379,016	16.48
TOTAL PROVED PLUS PROBABLE	**2,524,220**	**1,875,788**	**1,476,415**	**1,210,308**	**1,022,079**	**16.59**

Notes:
(1) Unit values based on Company net interest reserves.
(2) The prices used to estimate net present values are the average of those used by the largest three independent industry reserve evaluators.
(3) Columns may not add due to rounding.

Reconciliation of Company Gross Reserves Based on Forecast Prices and Costs

FACTORS	MBOE Proved	MBOE Probable	MBOE Proved + Probable
December 31, 2018	**55,651**	**45,921**	**101,572**
Extensions and Improved Recovery[1]	10,874	862	11,736
Technical Revisions	285	(2,623)	(2,338)
Acquisitions	266	87	353
Dispositions	(69)	(94)	(162)
Economic Factors	(334)	(408)	(742)
Production	(8,786)	0	(8,786)
December 31, 2019	**57,886**	**43,746**	**101,632**

Notes:
(1) Reserves additions under Infill Drilling, Improved Recovery and Extensions are combined and reported as "Extensions and Improved Recovery".
(2) Columns may not add due to rounding.
(3) Company Gross Reserves exclude royalty volumes.

Future Development Capital Costs

The following is a summary of GLJ's estimated future development capital required to bring proved and probable undeveloped reserves on production.

Future Development Capital[1]

(amounts in $000s)	Total Proved	Total Proved + Probable
2020	111,109	157,211
2021	138,448	166,499
2022	106,580	169,691
2023 and Subsequent	42,398	209,323
Total Undiscounted FDC	398,535	702,724
Total Discounted FDC at 10% per year	338,673	570,433

Note:
(1) FDC as per GLJ independent reserve evaluation effective December 31, 2019 based on GLJ forecast pricing.

FD&A Costs

	2019		Three Year Average	
(amounts in $000s except as noted)	**TP**	**TPP**	**TP**	**TPP**
FD&A costs, including FDC[(1)(2)]				
Exploration and development capital expenditures [(3)(4)]	178,966	178,966	195,951	195,951
Acquisitions, net of dispositions[(5)]	9,942	9,942	136,765	136,765
Total change in FDC	16,965	2,551	54,596	100,635
Total FD&A capital, including change in FDC	205,873	191,459	387,312	433,351
Reserve additions, including revisions – Mboe	10,825	8,656	11,187	14,629
Acquisitions, net of dispositions[(5)] – Mboe	197	191	5,301	8,728
Total FD&A Reserves	11,022	8,847	16,488	23,357
F&D costs, including FDC - $/boe	18.10	20.97	19.70	16.40
Acquisition costs, net of dispositions - $/boe	50.57	52.13	31.48	22.16
FD&A costs, including FDC - $/boe	18.68	21.64	23.49	18.55

Notes:
(1) 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.
(2) 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.
(3) 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.
(4) The capital expenditures also exclude capitalized administration costs.
(5) Includes capital spent in 2019 to develop the assets acquired during 2019.
(6) Columns may not add due to rounding.
(7) Calculations using Company Gross Reserves which exclude royalty volumes.

2020 Guidance

Tamarack maintains a disciplined capital allocation strategy that is designed to achieve sustainability through environments of weak and volatile oil prices, while continuing to direct free adjusted funds flow to purchase its common shares for cancellation under the NCIB program and for future RSU settlement. The Company is committed to maintaining flexibility in order to respond to the volatile price environment and will continue to monitor the 2020 capital program in light of the changing environment. The 2020 plan remains fully funded by adjusted funds flow at current commodity prices. As a result, our 2020 guidance remains unchanged from previously provided details, with plans to invest between $170 and $180 million. This capital program is anticipated to result in average production of 23,500 – 24,500 boe/d (64-66% oil and NGL). Supported by the Company's exceptional operational execution, Tamarack remains committed to investing in longer-term projects, including the Veteran waterflood, which is expected to further improve oil recoveries, reduce corporate decline rates, increase production rates and further augment Tamarack's sustainability.

In 2020, the Company has earmarked approximately $50 to $58 million of its 2020 capital budget to the continued development of the Veteran waterflood project.

Tamarack is also committed to understanding and managing the risks associated with environmental, social and governance ("ESG") factors in its business. As part of the Company's 2020 plan, Tamarack will deliver ESG related results through improved transparency and disclosure, as well as the development of clear, measurable targets tied to executive compensation and focused on key issues that are relevant to the business including: carbon intensity; fresh water management; land use; and engagement of valued community partners.

The Company's 2020 guidance and assumptions are outlined below:

- Capital budget is between $170 and $180 million which is forecast to maintain volumes consistent with the Company's 2019 annual average production of 23,500 to 24,500 boe/d (64% to 66% oil and NGL), with further increases in the oil and NGL weightings by the end of the year.
- Oil weighting to increase by 7% -12% in 2020. Anticipated increases in waterflood response at Veteran are expected to partially offset Tamarack's corporate oil decline rate, resulting in the Company exiting Q4/20 with an oil weighting ranging between 59% and 62%, an increase from 57% in Q4/19, while its total liquids weighting at exit 2020 is expected to range between 65% and 68%, increasing from 63% in Q4/19.

About Tamarack Valley Energy Ltd.

Tamarack is an oil and gas exploration and production company committed to long-term growth and the identification, evaluation and operation of resource plays in the Western Canadian Sedimentary Basin. Tamarack's strategic direction is focused on two key principles: (i) targeting repeatable and relatively predictable plays that provide long-life reserves; and (ii) using a rigorous, proven modeling process to carefully manage risk and identify opportunities. The Company has an extensive inventory of low-risk, oil development drilling locations focused primarily in the Cardium and Viking fairways in Alberta that are economic over a range of oil and natural gas prices. With this type of portfolio and an experienced and committed management team, Tamarack intends to continue delivering on its strategy to maximize shareholder returns while managing its balance sheet.

Abbreviations

bbls	barrels
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousands barrels of oil equivalent
mcf	thousand cubic feet
GJ	gigajoule
MMcf	million cubic feet
Mbbls	thousand barrels
mcf/d	thousand cubic feet per day

WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
AECO	the natural gas storage facility located at Suffield, Alberta connected to TC Energy's Alberta System
IFRS	International Financial Reporting Standards as issued by the International Accounting Standards Board

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 NI 51-101. Boe may be misleading, particularly if used in isolation.

Reserves Disclosure. All reserve references in this press release are "Company gross reserves". Company gross reserves are the Company's total working interest reserves before the deduction of any royalties payable by the Company. 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.

Oil and Gas Metrics. This press release contains metrics commonly used in the oil and natural gas industry, such as development capital, F&D costs, FD&A costs, recycle ratio, reserve life index and net asset value.

> "**Development capital**" means the aggregate exploration and development costs incurred in the financial year on reserves that are categorized as development. Development capital presented herein excludes land and capitalized administration costs but includes the cost of acquisitions and capital associated with acquisitions where reserve additions are attributed to the acquisitions.
>
> "**Finding and development costs**" are calculated as the sum of field capital plus the change in FDC for the period divided by the change in reserves that are characterized as development for the period and "finding, development and acquisition costs" are 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. Both finding and development costs and finding development and acquisition costs take into account reserves revisions during the year on a per boe basis. The aggregate of the exploration and development costs incurred in the financial year and changes during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. Finding and development costs both including and excluding acquisitions and dispositions have been presented in this press release because acquisitions and dispositions can have a significant impact on Tamarack's ongoing reserves replacements costs and excluding these amounts could result in an inaccurate portrayal of the Company's cost structure.
>
> "**Recycle ratio**" is measured by dividing the operating netback for the applicable period by F&D cost per boe for the year. The recycle ratio compares 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.

"**Reserve life index**" is calculated as total Company interest reserves divided by annual production.

"**Net asset value**" is based on present value of future net revenues discounted at 10% before tax on reserves, net of estimated net debt at year end divided by the basic shares outstanding at year end.

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 press release, should not be relied upon for investment or other purposes.

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; development of the waterflood projects in 2020 and the impact thereon on oil recoveries, corporate decline rates, production rates and capital efficiencies; the payout of wells and the timing thereof; Tamarack's capital allocation strategy that is designed to achieve sustainability through environments of weak and volatile oil prices; continuing to direct free adjusted funds flow to repurchase its Shares under its NCIB program and to be held in trust for future RSU settlements; the 2020 capital budget, guidance and plan, including the Company's expectation to remain fully funded by adjusted operating netback, its commitment to investing in longer-term projects, including the waterflood and its plan to deliver ESG related results and develop measurable targets relating thereto; oil and natural gas production levels, including annual average production and exit production in 2020; oil and liquids weighting; the waterflood response and impact thereof on corporate decline rates; liquidity on existing credit facilities; shareholder returns; and enhanced per share metrics. 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: 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; the application of regulatory and licensing requirements; the continued availability of capital and skilled personnel; the ability to maintain or grow the banking facilities; and the accuracy of Tamarack's geological interpretation of its drilling and land opportunities, including the ability of seismic activity to enhance such interpretation.

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: 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; health, safety, litigation and environmental risks; and access to capital. Due to the nature of the oil and natural gas industry, drilling plans and operational activities may be delayed or modified to react to market conditions, results of past operations, regulatory approvals or availability of services causing results to be delayed. Please refer to 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 and the Company's AIF for the year ended December 31, 2019 which will be filed on SEDAR before open of business March 5, 2020.

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 Tamarack's prospective results of operations, production, weightings, estimated year end 2020 net debt to Q4 annualized adjusted funds flow ratio 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 made as of the date of this document and was provided for the purpose of providing further information about Tamarack's future business operations. 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.

Non-IFRS Measures

Certain financial measures referred to in this press release, such as net debt, debt-adjusted production per share, adjusted funds flow, free adjusted funds flow and net debt to annualized adjusted funds flow ratio, are not prescribed by IFRS. Tamarack uses these measures to help evaluate its financial and operating performance as well as its 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 bank debt plus working capital surplus or deficit, including the fair value of cross-currency swaps and excluding the fair value of financial instruments and lease liabilities.

"Debt adjusted production per share" is a measure of changes in production on a per share basis, with the number of shares adjusted based on changes to net debt outstanding for the periods being compared. Debt-adjusted share count is calculated as total shares outstanding plus incremental shares issued at a current market price to eliminate the change in net debt or in the case where debt decreases the reduction in shares. Management of Tamarack believes that debt adjusted production per share is useful in determining the production growth on a per share basis as if changes to debt were extinguished by the issuance or redemption of shares. The presentation of production growth on a per share basis is skewed for oil and gas companies that have more debt on their balance sheet and in their capital structure. Such companies will show better results because more of their growth is financed through debt than equity (as opposed to generating growth through realizing a rate of return on capital employed). The debt adjusted production per share measure provides a means of putting oil and gas companies on an equal, enterprise-based footing with respect to debt when calculating per share numbers. This measure allows investors to appreciate the impact that debt on a company's balance sheet has on per share growth and allows them to evaluate the strength of one company's balance sheet relative to an over-leveraged peer. This is particularly relevant during periods of volatile commodity price when a company's indebtedness may increase as a result of lower cash flows and higher debt financing costs.

"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. 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 (loss) per share.

"Free adjusted funds flow" is calculated by taking adjusted funds flow and subtracting capital expenditures, excluding acquisitions and dispositions, Management believes that free adjusted 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 debt to annualized adjusted funds flow ratio" is calculated as net debt divided by annualized adjusted funds flow for the most recent quarter.

"Operating Field Netback" is calculated as total petroleum and natural gas sales, less royalties and net production and transportation costs.

"Operating Netback" is calculated as total petroleum and natural gas sales, including realized gains and losses on commodity, interest rate and foreign exchange derivative contracts, less royalties and net production and transportation costs.

Please refer to the MD&A for additional information relating to Non-IFRS measures. The MD&A can be accessed either on Tamarack's website at www.tamarackvalley.ca or under the Company's profile on www.sedar.com.

For additional information, please contact:

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