tamarack valley ENERGY

**TSX: TVE**

# Tamarack Valley Energy Ltd. Announces Fourth Quarter and Year End 2020 Financial Results and Reserves Highlights

**Calgary, Alberta – March 1, 2021** – 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, 2020 and the results of its independent oil and gas reserves evaluation as of December 31, 2020, prepared by GLJ 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, 2020, 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, 2020 has been filed on SEDAR today and is also available on Tamarack's website.

Brian Schmidt, President and Chief Executive Officer of Tamarack commented, "2020 brought with it many challenges for the industry as a whole. Despite the extreme volatility, economic damage and pricing uncertainty caused by the COVID-19 pandemic, we were able to effectively manage our business with a focus on maintaining financial strength and executed on two strategic acquisitions: the West Central acquisition in July and the transformational entry into the highly economic Clearwater oil play in December. The combined acquisitions supplement our highly economic drilling location runway by approximately 471 (403.9 net) wells and enhance the underlying sustainability of the Company through a 23% blended acquisition decline rate. Furthermore, 2020 represented significant growth in our Veteran Viking waterflood reserves which will serve to mitigate corporate declines and enhance our sustainability. Looking forward to 2021, we are focused on maximizing our free adjusted funds flow (see "Non-IFRS Measures") through a $105-$110 million capital program focused on the Clearwater and the Veteran waterflood oil programs which will enable aggregate production growth of approximately 5% and increase oil weighting by approximately 30% at exit 2021 compared to 2020, as previously announced on January 11th, 2021. In addition, we remain focused on further advancing the 2021 initiatives and targets set within our robust environmental, social and governance ("ESG") reporting frameworks."

## Q4 2020 Financial and Operating Highlights

- Announced the transformational entrance into the Clearwater oil play on December 21, 2020 through two strategic acquisitions establishing a significant consolidated and operated position of approximately 107,000 net acres along with approximately 2,000 bbls/d of oil production, for total cash consideration of $94.9 million. These acquisitions were financed through a combination of debt and a $47.1 million private placement (40.9 million shares issued at $1.15 per share), along with a Gross Overriding Royalty ("GORR") disposition on specific acquisition lands in the Clearwater for proceeds of approximately $15.5 million.
- Achieved quarterly production volumes of 22,049 boe/d in Q4/20, representing a 2% increase from the previous quarter while 2020 annual volumes averaged 22,027 boe/d.
- Generated adjusted funds flow (see "Non-IFRS Measures") of $28.9 million in Q4/20 ($0.13 per share basic and diluted) and $122.7 million for the full year 2020 ($0.55 per share basic and diluted) in addition to free adjusted funds flow (see "Non-IFRS Measures") of $19.2 million for the year.
- Invested $13.1 million and $103.5 million in exploration and development capital expenditures ("E&D"), excluding acquisitions, during Q4/20 and full year 2020, respectively, which contributed to drilling 72 (69.9 net) wells, comprised of 57 (55.8 net) Viking oil wells, one (0.8 net) Viking gas well, six (5.3 net) Cardium

oil wells, one (1.0 net) Clearwater oil well, two (2.0 net) Penny Banff light oil wells and five (5.0 net) water source and injector wells. Significant capital continued to be directed to our Viking waterflood program, which represented approximately 34% of the total E&D capital expenditures.

- Effectively managed our financial strength in 2020, exiting the year with approximately $219.3 million in net debt.
- Successfully executed on our Viking waterflood program, with exit 2020 production of approximately 1,900 bbls/d of light oil, which represents growth of 109% over 2019 exit.
- Released an inaugural Sustainability Report highlighting Tamarack's ongoing commitment to ESG factors with specific and measurable goals related to the Company's key priorities.

## Clearwater Update

Tamarack continues to be active in the play with 12 wells rig released out of a planned 16 well first quarter $18 million program. Of the 12 wells rig released, three wells have produced oil for more than 30 days and exhibited stabilized average IP30 rates of approximately 200 bbl/d, which is approximately 36% higher than Tamarack's Nipisi internal type 1 curve of 147 bbl/d (see the Company's investor presentation for additional details). The Company plans to keep one rig active through Q2, ramping back up to two rigs in Q3, directing $53-$55 million in capital for 2021; with $45-$47 million allocated to drilling activity and $8 million on gas conservation and infrastructure initiatives. This investment is forecast to grow production in the Clearwater to 4,500 to 5,500 boe/d[1] in the fourth quarter of 2021, representing 150% growth from the 2,000 boe/d acquired in December of 2020.

## Financial & Operating Results

| | Three months ended December 31, | | | Years ended December 31, | | |
|---|---|---|---|---|---|---|
| | **2020** | 2019 | % change | **2020** | 2019 | % change |
| ***($ thousands, except per share)*** | | | | | | |
| Total oil, natural gas and processing revenue | **64,873** | 98,130 | (34) | **222,073** | 382,816 | (42) |
| Cash flow from operating activities | **23,859** | 54,623 | (56) | **125,290** | 205,231 | (39) |
| Per share – basic | **$ 0.11** | $ 0.24 | (54) | **$ 0.56** | $ 0.91 | (38) |
| Per share – diluted | **$ 0.11** | $ 0.24 | (54) | **$ 0.56** | $ 0.91 | (38) |
| Adjusted funds flow [1] | **28,894** | 54,742 | (47) | **122,748** | 219,434 | (44) |
| Per share – basic [1] | **$ 0.13** | $ 0.25 | (48) | **$ 0.55** | $ 0.97 | (43) |
| Per share – diluted [1] | **$ 0.13** | $ 0.25 | (48) | **$ 0.55** | $ 0.97 | (43) |
| Net income (loss) | **(18,220)** | (50,546) | 64 | **(311,384)** | (39,011) | (698) |
| Per share – basic | **$ (0.08)** | $ (0.23) | 65 | **$ (1.40)** | $ (0.170) | (724) |
| Per share – diluted | **$ (0.08)** | $ (0.23) | 65 | **$ (1.40)** | $ (0.170) | (724) |
| Net debt [1] | **(219,311)** | (189,481) | 16 | **(219,311)** | (189,481) | 16 |
| Capital expenditures [2] | **13,088** | 22,954 | (43) | **103,543** | 178,966 | (42) |
| **Weighted average shares outstanding *(thousands)*** | | | | | | |
| Basic | **226,213** | 223,305 | 1 | **222,781** | 225,219 | (1) |
| Diluted | **226,213** | 223,305 | 1 | **222,781** | 225,219 | (1) |

[1] Comprised of 4,500 – 5,500 bbls/d of heavy crude oil, with no forecast NGL or conventional natural gas volumes.

| | | | | | | |
|---|---|---|---|---|---|---|
| **Share Trading** *(thousands, except share price)* | | | | | | |
| High | **$ 1.41** | $ 2.05 | (31) | **$ 2.27** | $ 3.09 | (27) |
| Low | **$ 0.69** | $ 1.59 | (57) | **$ 0.39** | $ 1.59 | (75) |
| Trading volume (thousands) | **78,236** | 35,103 | 123 | **259,895** | 179,985 | 44 |
| **Average daily production** | | | | | | |
| Light oil (bbls/d) | **10,544** | 13,729 | (23) | **11,203** | 13,103 | (15) |
| Heavy oil (bbls/d) | **128** | 318 | (60) | **156** | 440 | (65) |
| NGL (bbls/d) | **2,421** | 1,735 | 40 | **1,930** | 1,622 | 19 |
| Natural gas (mcf/d) | **53,738** | 54,462 | (1) | **52,426** | 53,444 | (2) |
| Total (boe/d) | **22,049** | 24,859 | (11) | **22,027** | 24,072 | (8) |
| **Average sale prices** | | | | | | |
| Light oil ($/bbl) | **47.58** | 64.26 | (26) | **41.47** | 66.25 | (37) |
| Heavy oil ($/bbl) | **40.90** | 58.96 | (31) | **36.43** | 55.27 | (34) |
| NGL ($/bbl) | **24.40** | 21.96 | 11 | **20.90** | 25.57 | (18) |
| Natural gas ($/mcf) | **2.46** | 2.26 | 9 | **1.77** | 2.06 | (14) |
| Total ($/boe) | **31.67** | 42.72 | (26) | **27.40** | 43.37 | (37) |
| **Operating netback ($/Boe) [1]** | | | | | | |
| Average realized sales | **31.67** | 42.72 | (26) | **27.40** | 43.37 | (37) |
| Royalty expenses | **(3.31)** | (4.39) | (25) | **(3.04)** | (4.45) | (32) |
| Net production and transportation expenses | **(11.71)** | (9.96) | 18 | **(10.59)** | (10.03) | 6 |
| **Operating field netback ($/Boe) [1]** | **16.65** | 28.37 | (41) | **13.77** | 28.89 | (52) |
| Realized commodity hedging gain (loss) | **0.52** | (2.04) | (125) | **4.09** | (1.42) | (388) |
| Operating netback | **17.17** | 26.33 | (35) | **17.86** | 27.47 | (35) |
| **Adjusted funds flow ($/Boe) [1]** | **14.24** | 23.94 | (41) | **15.23** | 24.98 | (39) |

**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

## 2020 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 press release include changes in future development capital ("FDC"). The ongoing positive impact of Tamarack's Veteran waterflood program and West Central asset acquisitions contributed significantly to the reserves in 2020 and, when combined with the Clearwater acquisitions, enhance the resiliency and sustainability of the Company in 2021 and beyond.

- Recognized significant contribution from Tamarack's Veteran waterflood program in 2020, with the Company's reserves for the waterflood program increasing by 294% on a PDP basis to 3.2 MMboe, 27% on TP to 6 MMboe, and 27% on TPP to 12.4 MMboe relative to 2019. These increases also illustrate the positive impact of the waterflood on our corporate decline rate, which is estimated to be in the 22 to 24% range (exit to exit) in 2021 while also serving to enhance the Company's overall sustainability.

- Relative to year-end 2019, Tamarack increased PDP reserves 18% to 40.5 MMboe, TP reserves 10% to 64 MMboe and TPP reserves 9% to 111 MMboe in 2020. These growth rates are consistent on a weighted average per share basis.

- Replaced 176% of total 2020 production on a PDP basis, 174% on a TP basis and 219% on a TPP basis. PDP reserves represent 63% and 36% of TP and TPP reserves, respectively.

- Relative to year end 2019, reported 16% lower PDP FD&A costs of $14.02/boe with a 1.3x recycle ratio (see "Oil and Gas Metrics"), 48% lower TP FD&A costs of $9.73/boe with a 1.8x recycle ratio, and 68% lower TPP FD&A costs of $6.90/boe with a 2.6x recycle ratio, all based on the 2020 average operating field netback of $17.86/boe, including hedges.
- Before-tax net present value ("NPV") of reserves, discounted at 10%, was $426 million on a PDP basis, $660 million on a TP basis and $1.2 billion on a TPP basis evaluated on three independent reserve evaluators average forecast pricing and foreign exchange rates as at January 2021.
- Achieved an increase in year-over-year reserve life index ("RLI") (see "Oil and Gas Metrics") across all reserve categories totaling 13.8 years on TPP, 7.9 years on TP and 5 years on PDP, based on 2020 average production of 22,027 boe/d.

**2020 Independent Qualified Reserve Evaluation**

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 most recent publication of Canadian Oil and Gas Evaluation Handbook. All evaluations and summaries of future net revenue are stated prior to the 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 the following three independent external reserves evaluators: GLJ Ltd., Sproule, and McDaniel & Associates Consultants Ltd ("3-Consultant Average Forecast Pricing"). 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. All per share reserves metrics below are based on basic shares outstanding.

## Reserves Snapshot by Category:

| | PDP | TP | TPP |
|---|---|---|---|
| Total Reserves (mboe)[1] | 40,507 | 63,839 | 111,171 |
| Reserves Added[2] (mboe) | 14,145 | 14,015 | 17,601 |
| Reserves Replacement | 175% | 174% | 218% |
| NPV10 BT ($mm) | $426 | $660 | $1,183 |

**Notes:**
(1) Total reserves are Company Gross Reserves which exclude royalty volumes
(2) Reserves Added takes the difference in reserves year-over-year plus the production for the year

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

| (mboe) | December 31, 2020 [1] | December 31, 2019 [1] | % Change |
|---|---|---|---|
| **PDP** | 40,507 | 34,424 | 18% |
| **TP** | 63,839 | 57,886 | 10% |
| **TPP** | 111,171 | 101,632 | 9% |

**Note:**
(1) Total reserves are Company Gross Reserves which exclude royalty volumes

## Recycle Ratios

| | PDP | TP | TPP |
|---|---|---|---|
| FD&A Cost per boe[1] | $14.02 | $9.73 | $6.90 |
| Recycle Ratio (unhedged)[2] | 0.98x | 1.42x | 2.00x |
| Recycle Ratio (hedged)[3] | 1.27x | 1.84x | 2.59x |
| F&D Cost per boe[1] | $23.08 | $18.71 | $8.32 |
| Recycle Ratio (unhedged)[2] | 0.60x | 0.74x | 1.66x |
| Recycle Ratio (hedged)[3] | 0.77x | 0.95x | 2.15x |

**Notes:**
(1) 2020; including changes in FDC
(2) Based on unhedged 2020 operating netback of $13.77 per boe
(3) Based on hedged 2020 operating netback of $17.86 per boe

## Reserves Data (Forecast Prices and Costs) – Company Gross

| | LIGHT & MEDIUM CRUDE OIL[1] | | CONVENTIONAL NATURAL GAS[2] | | NATURAL GAS LIQUIDS | | TOTAL OIL EQUIVALENT | |
|---|---|---|---|---|---|---|---|---|
| **RESERVES CATEGORY** | **Gross (Mbbls)** | **Net (Mbbls)** | **Gross (Mmcf)** | **Net (Mmcf)** | **Gross (Mbbls)** | **Net (Mbbls)** | **Gross (Mboe)** | **Net (Mboe)** |
| PROVED: | | | | | | | | |
| Developed Producing | 18.452 | 16,222 | 100,426 | 91,383 | 5,317 | 4,466 | 40,507 | 35,919 |
| Developed Non-Producing | 1,312 | 1,242 | 2,867 | 2,668 | 51 | 39 | 1,841 | 1,725 |
| Undeveloped | 13,679 | 12,385 | 38,172 | 34,983 | 1,451 | 1,299 | 21,492 | 19,514 |
| **TOTAL PROVED** | **33,442** | **29,848** | **141,466** | **129,034** | **6,819** | **5,804** | **63,839** | **57,158** |
| PROBABLE | 27,824 | 24,477 | 91,348 | 83,712 | 4,283 | 3,746 | 47,332 | 42,175 |
| **TOTAL PROVED PLUS PROBABLE** | **61,266** | **54,325** | **232,813** | **212,746** | **11,102** | **9,549** | **111,171** | **99,333** |

**Notes:**
(1) Heavy oil and tight oil included in the crude oil product type represents less than 15.8% 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 | 542,230 | 477,932 | 426,368 | 385,553 | 352,769 | 11.87 |
| Developed Non-Producing | 54,882 | 48,894 | 41,999 | 36,065 | 31,202 | 24.34 |
| Undeveloped | 344,513 | 254,801 | 191,934 | 147,241 | 114,656 | 9.84 |
| **TOTAL PROVED** | **941,625** | **781,627** | **660,301** | **568,859** | **498,627** | **11.55** |
| PROBABLE | 1,067,833 | 722,779 | 522,259 | 397,105 | 313,809 | 12.38 |
| **TOTAL PROVED PLUS PROBABLE** | **2,009,458** | **1,504,406** | **1,182,560** | **965,964** | **812,436** | **11.91** |

**Notes:**
(1) Unit values based on Company net interest reserves
(2) The prices used to estimate net present values are 3 Consultant Average forecast pricing
(3) Columns may not add due to rounding

## Reconciliation of Company Gross Reserves Based on Forecast Prices and Costs

| | MBOE | | |
|---|---|---|---|
| **FACTORS** | **TP** | **Probable** | **TPP** |
| December 31, 2019 | **57,886** | **43,746** | **101,632** |
| Extensions and Improved Recovery[1] | 3,826 | 1,406 | 5,231 |
| Technical Revisions | 534 | (3,922) | (3,389) |
| Acquisitions | 13,167 | 8,167 | 21,334 |
| Dispositions | - | - | - |
| Economic Factors | (3,511) | (2,064) | (5,576) |
| Production | (8,062) | 0 | (8,062) |
| **December 31, 2020** | **63,839** | **47,332** | **111,171** |

**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 TP and TPP undeveloped reserves on production.

### Future Development Capital[1]

| (amounts in $000s) | TP | TPP |
|---|---|---|
| 2021 | 57,042 | 82,674 |
| 2022 | 95,311 | 116,783 |
| 2023 | 112,504 | 145,482 |
| 2024 and Subsequent | 83,180 | 292,394 |
| Total Undiscounted FDC | 348,036 | 637,332 |
| Total Discounted FDC at 10% per year | 281,954 | 492,481 |

**Note:**
(1) FDC as per GLJ independent reserve evaluation effective December 31, 2020 based on 3 Consultant Average forecast pricing

## FD&A Costs

| | 2020 | | 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] | 103,543 | 103,543 | 166,364 | 166,364 |
| Acquisitions, net of dispositions[5] | 83,286 | 83,286 | 31,952 | 31,952 |
| Total change in FDC | (50,499) | (65,392) | (4,321) | (19,142) |
| **Total FD&A capital, including change in FDC** | 136,330 | 121,437 | 193,995 | 179,174 |
| Reserve additions, including revisions – Mboe | 848 | (3,733) | 7,761 | 7,408 |
| Acquisitions, net of dispositions[5] – Mboe | 13,167 | 21,334 | 4,831 | 7,726 |
| **Total FD&A Reserves** | 14,015 | 17,601 | 12,591 | 15,135 |
| F&D costs, including FDC - $/boe | 18.71 | 8.32 | 19.19 | 16.57 |
| Acquisition costs, net of dispositions - $/boe | 9.15 | 7.15 | 9.34 | 7.30 |
| **FD&A costs, including FDC - $/boe** | 9.73 | 6.90 | 15.41 | 11.84 |

**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 2020 to develop the assets acquired during 2020.
(6) Columns may not add due to rounding
(7) Calculations using Company Gross Reserves which exclude royalty volumes.

**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, Clearwater 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 |
| Mbbls | thousand barrels |
| boe | barrels of oil equivalent |
| boe/d | barrels of oil equivalent per day |
| Mboe | thousand barrels of oil equivalent |
| mcf | thousand cubic feet |
| mcf/d | thousand cubic feet per day |
| MMcf | million cubic feet |
| GJ | Gigajoule |
| IFRS | International Financial Reporting Standards as issued by the International Accounting Standards Board |
| IP30 | initial 30 day production |

## 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 cost 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 and reserve life index.

> "**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.

"**Finding, development and acquisition costs**" incorporate 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.

"**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.

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.

**Drilling Locations**. This press release discloses drilling locations in 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 Canadian Oil and Gas Evaluation 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 471 (403.9 net) drilling locations identified herein, 21 (19.2 net) are proved locations, 18 (16.3 net) are probable locations and 432 (368.4 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.

## 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, including future development of the assets acquired pursuant to the Clearwater acquisitions and the West Central acquisition; development of the waterflood projects in 2020 and the impact thereon on oil recoveries, corporate and blended acquisition decline rates, production rates and capital efficiencies; the payout of wells and the timing thereof; Tamarack's commitment to ESG principles; measures taken in response to COVID-19 and plans relating thereto; Tamarack's capital allocation strategy; the 2021 capital budget, guidance and plan; oil and natural gas production levels, including annual average production and exit production in 2021; oil and liquids weighting; the waterflood response and impact thereof on corporate and blended acquisition decline rates; 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; access to capital; and the COVID-19 pandemic. 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 AIF and 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 Tamarack's prospective results of operations and production, weightings, corporate decline rates, balance sheet, net debt, adjusted funds flow, free adjusted funds flow 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 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, adjusted funds flow free adjusted funds flow, operating field netback and operating netback 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.

**"Adjusted funds flow"** Adjusted funds flow is calculated by taking cash-flow from operating activities and adding back changes in non-cash working capital and expenditures on decommissioning obligations since Tamarack believes the timing of collection, payment or incurrence of these items is variable. 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 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.

**"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.

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