MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the three months and years ended December 31, 2020 and 2019. This MD&A is dated and based on information available as at February 26, 2021 and should be read in conjunction with the audited consolidated financial statements ("financial statements") and the notes thereto for the years ended December 31, 2020 and 2019. Additional information relating to Tamarack, including Tamarack's Annual Information Form for the year ended December 31, 2020, is available on SEDAR at www.sedar.com and Tamarack's website at www.tamarackvalley.ca.

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The Company uses certain non-IFRS measures in this MD&A. For a discussion of those measures, including the method of calculation, please refer to the section titled "Non-IFRS Measures" beginning on page 21. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

Strategic Acquisitions

On December 21, 2020, the Company announced the transformational entrance into the Clearwater oil play ("Clearwater Acquisition") through two strategic acquisitions establishing a significant consolidated and operated position of approximately 107,000 net acres along with approximately 2,000 barrels per day of oil production, acquired for total cash consideration of $94.9 million. These acquisitions furthered our strategy of building a strategic platform focused on enhancing the resiliency of our free adjusted funds flow (see "Non-IFRS Measures") through one of the most profitable oil plays in North America. The acquisitions were financed through a combination of debt, a $47.1 million private placement (40.9 million common shares at $1.15 per share) in December 2020, along with a Gross Overriding Royalty ("GORR") disposition on specific Clearwater Acquisition lands for proceeds of approximately $15.5 million.

On July 9, 2020, the Company completed the acquisition of certain light oil and liquids rich natural gas properties located in West Central Alberta (the "West Central Acquisition"). Given the location and proximity of the acquired assets to the Company's existing Cardium oil CGU, the acquired properties are synergistic to the Company's operated infrastructure. The assets include approximately 2,500 boe/d (52% oil and NGL) of low-decline production supported by a high-quality, multi-zone light oil and liquids rich natural gas drilling inventory and approximately 105,000 net acres of land, acquired for total cash consideration of $4.0 million.

These combined acquisitions, added approximately 4,500 boe/d of production, 212,000 net acres of land, with a blended decline rate of approximately 23% for a total cost of $98.9 million.

Q4 & Year End 2020 Financial and Operating Highlights

- Achieved quarterly production volumes of 22,049 boe/d in Q4/20, representing a 2% increase from the previous quarter and 11% less than Q4/19 and average 2020 annual volumes of 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), compared to $54.7 million in Q4/19 ($0.25 per share basic and diluted). Generated adjusted funds flow of $122.7 million in 2020 ($0.55 per share basic and diluted), compared to $219.4 million in 2019 ($0.97 per share basic and diluted). Generated 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 the fourth quarter and the full year 2020, respectively, which contributed to the 2020 drilling of 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. The Company continued to direct significant capital 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.

Managing Through the Novel Coronavirus (COVID-19)

Considerable market volatility dominated 2020. The COVID-19 outbreak was declared a pandemic by the World Health Organization during the first quarter of 2020 which resulted in governments worldwide, including those in Canada, taking measures to contain the spread of the virus, reducing demand for crude oil along with other products and services. The fourth quarter was characterized by moderate improvements in near-term WTI pricing; however, Tamarack continues to foresee potential for on-going uncertainty in oil demand due to the longer-term economic impacts of the global COVID-19 pandemic, the potential impacts of new variant strains of the virus, global vaccine availability and the impact of the new Government administration in the United States on the petroleum industry, including pipeline approvals and potential shut-downs.

Tamarack continues to proactively respond to the safety and financial challenges of the COVID-19 pandemic. The Company has improved our flexibility and responsiveness by establishing capabilities and procedures for remote working and opening our corporate head office on a limited and intermittent basis during the third and fourth quarters. Tamarack remains committed to ensuring the health and safety of our skilled and valued employees, as well as the public in the communities in which we operate, going above and beyond both Provincial and Federal government protocols.

The Provincial and Federal governments in Canada have taken steps to provide various programs given the serious impacts of the spread of COVID-19, such as the Canada Emergency Wage Subsidy ("CEWS"), the Alberta Site Rehabilitation Program ("SRP") and the Saskatchewan Accelerated Site Closure Program ("ASCP"). Tamarack recognized $0.3 million through the CEWS program during the fourth quarter for a total of $1.3 million in 2020 and continues to apply for the various phases of the SRP and ASCP programs of which we have approximately $3.6 million approved and/or allocated to date, with $1.4 million being recognized in 2020.

Sustainability

Tamarack continues to be committed to advancing our environmental, social and governance ("ESG") practices as outlined in our inaugural Sustainability Report published in the third quarter of 2020. This report provides details on the Company's approach to sustainability, including our commitment to greenhouse gas emissions management and to continued Indigenous and community partnerships in the areas where Tamarack operates. In addition, the report highlights specific, measurable goals and targets related to key focus areas set by the Company.

Production

Quarter-over-Quarter	Q4 2020	Q3 2020	% change
Production			
Light oil (bbls/d)	**10,353**	10,309	–
Heavy oil (bbls/d)	**319**	159	101
Natural gas liquids (bbls/d)	**2,421**	2,162	12
Natural gas (mcf/d)	**53,738**	53,420	1
Total (boe/d)	**22,049**	21,533	2
Percentage of oil and NGL	**59%**	59%	–

Average production for Q4/20 increased 2% from the previous quarter due to the Company's fourth quarter drilling program that included two gross (2.0 net) Cardium oil wells, three gross (2.8 net) Viking wells, plus the Clearwater Acquisition adding 191 boe/d to the quarterly average based on the Clearwater Acquisition closing date of December 21, 2020. This was partially offset by expected declines from existing base production.

The Company's average oil and natural gas liquids ("NGL") weighting was 59% in both Q4/20 and Q3/20.

Year-over-Year	Three months ended December 31,			Years ended December 31,		
	2020	2019	% change	**2020**	2019	% change
Production						
Light oil (bbls/d)	**10,353**	13,729	(25)	**11,155**	13,103	(15)
Heavy oil (bbls/d)	**319**	318	–	**204**	440	(54)
Natural gas liquids (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)
Percentage of oil and NGL	**59%**	63%	(6)	**60%**	63%	(5)

Average production for Q4/20 and the year ended December 31, 2020 decreased 11% and 8%, respectively, compared to the same periods in 2019 due to expected declines of existing base production, partially offset by the Company's 2019 and 2020 drilling programs, the West Central Acquisition that closed on July 9, 2020 and the Clearwater Acquisition that closed on December 21, 2020. The Company's oil and NGL weighting was lower for Q4/20 and the year ended December 31, 2020 relative to the same periods in 2019 due to the West Central Acquisition having a lower oil and NGL weighting.

Petroleum and Natural Gas Sales

Quarter-over-Quarter	Q4 2020	Q3 2020	% change
Revenue ($ thousands)			
Oil and NGL	**$52,065**	$49,601	5
Natural gas	**12,173**	7,890	54
Total	**$64,238**	$57,491	12
Average realized price:			
Light oil ($/bbl)	**47.63**	46.77	2
Heavy oil ($/bbl)	**43.12**	38.31	13
Natural gas liquids ($/bbl)	**24.40**	23.57	4
Combined average oil and NGL ($/boe)	**43.22**	42.69	1
Natural gas ($/mcf)	**2.46**	1.61	53
Revenue ($/boe)	**31.67**	29.02	9
Benchmark pricing:			
West Texas Intermediate (US$/bbl)	**42.67**	40.94	4
Edmonton Par (Cdn$/bbl)	**50.25**	49.86	1
NYMEX monthly settlement (US$/mmbtu)	**2.66**	1.97	35
AECO daily index (Cdn$/mcf)	**2.55**	2.23	14
AECO monthly index (Cdn$/mcf)	**2.45**	2.13	15

Revenue per boe from oil, natural gas and NGL sales in Q4/20 was 9% higher than in Q3/20 primarily due to the slight commodity price improvements in Q4/20.

The WTI benchmark price increased by 4% to an average of US$42.67/bbl in the fourth quarter of 2020 compared to US$40.94/bbl in the prior quarter, while the WTI/Edmonton Par light oil differential widened through Q4/20, averaging US$4.07/bbl compared to US$3.51/bbl in Q3/20. The average Edmonton Par price increased 1% to $50.25/bbl in Q4/20 compared to $49.86/bbl in Q3/20. The fourth quarter was characterized by greater stability in WTI pricing compared to the extreme market volatility in early 2020. Continued uncertainty about near-term oil demand and the long-term economic impacts of the global COVID-19 pandemic introduces near-term pricing risk; however, pricing increases across the end of 2020 and into 2021, combined with stabilizing global production and demand, are positive indicators of a less volatile pricing environment for 2021. Tamarack will continue to prudently manage commodity price risk through hedging in order to effectively manage cash flow risk. Tamarack's realized light oil wellhead price for the three months ended December 31, 2020 increased 2% to $47.63/bbl from $46.77/bbl in the previous quarter.

Realized NGL prices increased 4% to $24.40/bbl in Q4/20 from $23.57/bbl in Q3/20. The increase is due largely to the increased WTI price in the quarter, which is the basis for condensate and butane pricing. While global oil and liquids inventories continue to decrease, Alberta's natural gas liquid inventory remains high, creating uncertainty in the NGL market pricing outlook. As a result of this uncertainty and the upcoming 2021/2022 contract negotiations, Tamarack expects some volatility in pricing through 2021 and into early 2022.

Tamarack's realized natural gas price increased 53% to $2.46/mcf in Q4/20 from $1.61/mcf in Q3/20. The AECO daily benchmark price increased 14% to $2.55/mcf in Q4/20 from $2.23/mcf in Q3/20, while the

NYMEX monthly settlement price increased 35% to US$2.66/mmbtu in Q4/20 from US$1.97/mmbtu in Q3/20. The increase in the Company's Q4/20 realized price and the benchmark prices compared to the previous quarter was primarily due to improved market conditions, seasonal winter heating demands and lower supply as a result of decreased drilling activity in 2020. The increase in Tamarack's realized price deviates slightly from the increases seen in the two indices due to the Company's diversification strategy that balances pricing exposure over multiple markets. Tamarack's exposure to diversified gas markets is expected to continue providing meaningful benefit through both risk mitigation and improvements in realized pricing over the long-term. Tamarack will also continue to manage commodity price risk through financial and physical hedges.

The Company continues to employ multiple third-party gas sales contracts featuring various end dates until 2022. These contracts provide diversification of the Company's natural gas price exposure and help mitigate individual market volatility risk.

Year-over-Year	Three months ended December 31,			Years ended December 31,		
	2020	2019	% change	**2020**	2019	% change
Revenue ($ thousands)						
Oil and NGL	**$52,065**	$86,398	(40)	**$186,885**	$340,835	(45)
Natural gas	**12,173**	11,301	8	**34,011**	40,231	(15)
Total	**$64,238**	$97,699	(34)	**$220,896**	$381,066	(42)
Average realized price:						
Light oil ($/bbl)	**47.63**	64.26	(26)	**41.46**	66.25	(37)
Heavy oil ($/bbl)	**43.12**	58.96	(27)	**38.36**	55.27	(31)
Natural gas liquids ($/bbl)	**24.40**	21.96	11	**20.90**	25.57	(18)
Combined average oil and NGL ($/boe)	**43.22**	59.51	(27)	**38.42**	61.58	(38)
Natural gas ($/mcf)	**2.46**	2.26	9	**1.77**	2.06	(14)
Revenue ($/boe)	**31.67**	42.72	(26)	**27.40**	43.37	(37)
Benchmark pricing:						
West Texas Intermediate (US$/bbl)	**42.67**	56.91	(25)	**39.40**	57.02	(31)
Edmonton Par (Cdn$/bbl)	**50.25**	66.86	(25)	**45.32**	69.76	(35)
NYMEX monthly settlement (US$/mmbtu)	**2.66**	2.62	2	**2.08**	2.78	(25)
AECO daily index (Cdn$/mcf)	**2.55**	2.46	4	**2.20**	1.51	46
AECO monthly index (Cdn$/mcf)	**2.45**	2.32	6	**2.13**	1.37	55

Revenue per boe from oil, natural gas and NGL sales for Q4/20 and the year ended December 31, 2020 decreased by 26% and 37%, respectively, compared to the same periods in 2019, primarily due to lower commodity prices realized in 2020 as a result of the COVID-19 pandemic and lower average oil and natural gas liquids weighting due to the West Central Acquisition.

The Company may use both financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates. All such transactions are conducted within risk management tolerances that are reviewed quarterly by Tamarack's Board of Directors. At December 31, 2020, the Company held derivative commodity, foreign exchange and interest rate contracts as noted in the following tables:

		Q1 2021	Q2 2021	Q3 2021	Q4 2021
West Texas Intermediate Crude Oil Derivatives					
WTI fixed price swap	**Volume (bbls/d)**	**2,000**	**1,750**	**–**	**–**
	Average Price (US$/bbl)	$41.33	$45.67	–	–
WTI fixed price swap (with swaption)[(1)]	**Volume (bbls/d)**	**2,500**	**2,000**	**500**	**–**
	Average Price (US$/bbl)	$45.25	$47.20	$50.00	–
WTI two-way collar (with swaption)[(2)]	**Volume (bbls/d)**	**1,500**	**1,500**	**–**	**–**
	Average Bought Put (US$/bbl)	$40.00	$40.00	–	–
	Average Sold Call (US$/bbl)	$51.17	$51.17	–	–
WTI two-way collar	**Volume (bbls/d)**	**500**	**750**	**1,000**	**1,000**
	Average Bought Put (US$/bbl)	$40.00	$41.67	$40.00	$40.00
	Average Sold Call (US$/bbl)	$50.00	$51.43	$50.50	$50.50
	Average Premium (US$/bbl)	$2.00	$1.67	$2.00	$2.00
WTI three-way collar	**Volume (bbls/d)**	**–**	**–**	**1,000**	**1,000**
	Average Bought Put (US$/bbl)	–	–	$40.00	$40.00
	Average Sold Call (US$/bbl)	–	–	$60.00	$60.00
	Average Sold Put (US$/bbl)	–	–	$32.00	$32.00
	Average Premium (US$/bbl)	–	–	$2.00	$2.00
Crude Oil Differential Derivatives					
Edmonton Par to WTI fixed price differential swap	**Volume (bbls/d)**	**4,250**	**4,250**	**3,250**	**3,250**
	Average Price (US$/bbl)	($5.70)	($5.70)	($5.68)	($5.68)
WCS to WTI fixed price differential swap	**Volume (bbls/d)**	**1,000**	**500**	**–**	**–**
	Average Price (US$/bbl)	($11.75)	($12.00)	–	–

(1) If fully exercised would result in additional fixed price hedges of: 1,500 bbls/day at $46.00 (Q2/21); 2,000 bbls/day at $47.22 (Q3/21); and 1,500 bbls/day at $46.00 (Q4/21).

(2) If fully exercised would result in additional fixed price hedges of 1,500 bbls/day at $51.17 (H2/21).

		Q1 2021	Q2 2021	Q3 2021	Q4 2021
CAD/USD Foreign Exchange Derivatives					
CAD/USD average rate forward	**Amount ($US/month)**	**$1,000,000**	**$1,000,000**	–	–
	Average Forward Rate (CAD/USD)	1.4140	1.4140	–	–
CAD/USD average rate forward (with extension option)[(1)]	**Amount ($US/month)**	**$500,000**	**$500,000**	–	–
	Average Forward Rate (CAD/USD)	1.3843	1.3843	–	–
CAD/USD collar style swap (with extension option)[(2)]	**Amount ($US/month)**	**$500,000**	**$500,000**	**$500,000**	**$500,000**
	Floor Forward Rate (CAD/USD)	1.3000	1.3000	1.3000	1.3000
	Ceiling Forward Rate (CAD/USD)	1.3615	1.3615	1.3615	1.3615

(1) If fully exercised would result in additional fixed price hedges of $500,000 USD at 1.3843 (H2/21).

(2) If fully exercised would result in additional fixed price hedges of $500,000 USD at 1.3615 (2022).

		2021	2022	2023	2024
Interest Rate Derivatives					
CDOR Interest Rate Fixed Price Swap	**Amount ($MM CAD/year)**	**$80.0**	**$80.0**	**$49.1**	**$6.4**
	Fixed Interest Rate	1.533%	1.533%	1.225%	1.043%

At December 31, 2020, the derivative commodity, foreign exchange and interest rate contracts were fair valued with a net liability value of $10.2 million (December 31, 2019 - $4.1 million net liability) recorded on the balance sheet. The Company had an unrealized loss of $10.0 million and $6.1 million recorded in earnings for the three months and year ended December 31, 2020, respectively, compared to an unrealized loss of $1.4 million and $23.7 million during the same periods in 2019. The Company manages risk for these contracts by engaging with a variety of counterparties, all of which are credit grade banking institutions or large purchasers of commodities in the normal course of business. All counterparties have been assessed for credit worthiness.

Since December 31, 2020, the Company has entered into the following financial contracts:

		Q1 2021	Q2 2021	Q3 2021	Q4 2021
West Texas Intermediate Crude Oil Derivatives					
WTI fixed price swap	***Volume (bbls/d)***	**–**	**500**	**250**	**–**
	Average Price (US$/bbl)	–	$49.60	$50.00	–
WTI two-way collar	***Volume (bbls/d)***	–	–	–	**500**
	Average Bought Put (US$/bbl)	–	–	–	$50.00
	Average Sold Call (US$/bbl)	–	–	–	$60.00
	Average Premium (US$/bbl)	–	–	–	$0.00
Crude Oil Differential Derivatives					
WCS to WTI fixed price differential swap	***Volume (bbls/d)***	**–**	**–**	**1,500**	**–**
	Average Price (US$/bbl)	–	–	($11.88)	–

All physical commodity contracts are considered executory contracts and are not recorded at fair value on the balance sheet. On settlement, the realized benefit or loss is recognized in oil and natural gas revenue.

At December 31, 2020, the Company held the following physical commodity contracts:

		Winter 20-21	Summer 21	Winter 21-22
Natural Gas Derivatives				
AECO 5A	**Volume (GJ/d)**	**7,500**	**20,000**	**15,000**
	Average Price (CAD/GJ)	$2.42	$2.43	$2.80
Chicago	**Volume (DTH/d)**	**2,000**	**–**	**–**
	Average Price (US$/DTH)	$3.01	**–**	**–**
MichCon	**Volume (DTH/d)**	**2,000**	**–**	**–**
	Average Price (US$/DTH)	$2.85	**–**	**–**
Dawn	**Volume (DTH/d)**	**2,000**	**–**	**–**
	Average Price (US$/DTH)	$3.01	**–**	**–**
Malin	**Volume (DTH/d)**	**4,000**	**4,000**	**–**
	Average Price (US$/DTH)	$2.99	$2.83	**–**
WADD	**Volume (DTH/d)**	**5,000**	**–**	**–**
	Average Price (US$/DTH)	$3.90	**–**	**–**

Since December 31, 2020, the Company has not entered into any physical commodity contracts.

Royalties

Quarter-over-Quarter	Q4 2020	Q3 2020	% change
Royalty expenses ($ thousands)	**$6,713**	$5,690	18
$/boe	**3.31**	2.87	15
Percent of sales (%)	**10**	10	–

Royalties as a percentage of revenue were similar in Q4/20 to Q3/20. On an absolute basis, royalty expense was higher in Q4/20 due to the increase in commodity prices and production quarter-over-quarter.

Year-over-Year	Three months ended December 31,			Years ended December 31,		
	2020	2019	% change	**2020**	2019	% change
Royalty expenses ($ thousands)	**$6,713**	$10,041	(33)	**$24,540**	$39,060	(37)
$/boe	**3.31**	4.39	(25)	**3.04**	4.45	(32)
Percent of sales (%)	**10**	10	–	**11**	10	10

Royalties as a percentage of revenue for the three months ended December 31, 2020 were similar to the same period in 2019. The Company expects royalty rates as a percentage of revenue to remain in the 10% to 11% range for 2021 based on current forecast commodity price levels.

Royalties as a percentage of revenue for the year ended December 31, 2020 were higher than the same period in 2019 due to the Company's natural gas production being priced at alternate markets to AECO. These markets experienced lower gas prices than AECO in 2020, resulting in lower revenue applied against royalty expense that is based on an AECO gas price.

Royalties per boe decreased for the three months and year ended December 31, 2020, by 25% and 32%, respectively, due to lower commodity prices realized in 2020 as a result of the COVID-19 pandemic.

Net Production and Transportation Expenses

Quarter-over-Quarter ($ thousands, except per boe)	Q4 2020	Q3 2020	% change
Production and transportation expenses	**$24,394**	$21,383	14
Less: processing income	**635**	299	112
Total net production and transportation expenses	**$23,759**	$21,084	13
Total ($/boe)	**$11.71**	$10.64	10

Gross and net production and transportation expenses for Q4/20 were higher than Q3/20 due higher per unit costs associated with the West Central Acquisition, an increase in workover activities and a return to pre-COVID-19 service and contracting costs as commodity prices improved quarter-over-quarter.

Year-over-Year	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2020**	2019	% change	**2020**	2019	% change
Production and transportation expenses	**$24,394**	$23,212	5	**$86,515**	$89,897	(4)
Less: processing income	**635**	431	47	**1,177**	1,750	(33)
Total net production and transportation expenses	**$23,759**	$22,781	4	**$85,338**	$88,147	(3)
Total ($/boe)	**$11.71**	$9.96	18	**$10.59**	$10.03	6

For the three months and year ended December 31, 2020, per unit net production and transportation expenses were higher compared to the same periods in 2019. This resulted from the West Central Acquisition properties having higher per unit net production and transportation expenses compared to the corporate average before the acquisition, along with an increase in workovers.

For the three months ended December 31, 2020, gross and net production and transportation expenses were higher compared to the same period in 2019 due to higher per unit net production and transportation expenses, partially offset by lower production.

For the year ended December 31, 2020, gross and net production and transportation expenses were lower compared to the same period in 2019 due to lower production, partially offset by higher per unit net production and transportation expenses.

Operating Netback

Quarter-over-Quarter			
($/boe)	**Q4 2020**	Q3 2020	% change
Average realized sales	**$31.67**	$29.02	9
Royalty expenses	**(3.31)**	(2.87)	15
Net production and transportation expenses	**(11.71)**	(10.64)	10
Operating field netback	**16.65**	15.51	7
Realized commodity hedging gain	**0.52**	2.42	(79)
Operating netback	**$17.17**	$17.93	(4)

The Company's operating netback (see "Non-IFRS Measures") decreased 4% in Q4/20 compared to Q3/20. This was primarily the result of higher per unit royalty, net production and transportation expenses and a lower realized hedging gain, partially offset by higher commodity prices realized in Q4/20.

Year-over-Year	Three months ended December 31,			Years ended December 31,		
($/boe)	**2020**	2019	% change	**2020**	2019	% change
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	**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)

For the three months and year ended December 31, 2020, operating netbacks were lower than the same periods in 2019 primarily due to lower commodity prices realized in 2020 and higher net production and transportation expenses, partially offset by lower royalties and a realized commodity hedge gain in both Q4/20 and the year ended December 31, 2020.

General and Administrative ("G&A") Expenses

Quarter-over-Quarter			
($ thousands, except per boe)	**Q4 2020**	Q3 2020	% change
Gross costs	**$4,488**	$3,953	14
Government emergency wage subsidy	**(305)**	(1,016)	(70)
Capitalized costs and recoveries	**(1,067)**	(918)	16
General and administrative costs	**$3,116**	$2,019	54
Total ($/boe)	**$1.54**	$1.02	51

Net G&A expenses for Q4/20 were higher than Q3/20 as the Company received higher CEWS support payments during the third quarter as well as costs incurred related to office flood damage and IT repairs.

The office flood caused minimal damage to the Company's critical IT infrastructure, resulted in no loss of Company data and caused minimal disruption to the Company's operations. The Company's IT backup and recovery plans were effective and the Company completed a previously planned transfer of the Company's critical IT infrastructure to secure third-party offsite server space with a large digital services company prior to year-end.

The federal government has extended the CEWS program through to June 2021 and the Company anticipates it will continue to apply for this benefit as long as it qualifies.

Year-over-Year	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2020**	2019	% change	**2020**	2019	% change
Gross costs	**$4,488**	$4,290	5	**$16,353**	$16,306	–
Government emergency wage subsidy	**(305)**	–	–	**(1,321)**	–	–
Capitalized costs and recoveries	**(1,067)**	(992)	8	**(3,950)**	(3,842)	3
General and administrative costs	**$3,116**	$3,298	(6)	**$11,082**	$12,464	(11)
Total ($/boe)	**$1.54**	$1.44	7	**$1.37**	$1.42	(4)

Gross G&A costs for Q4/20 were higher compared to the same period in 2019, due to costs incurred related to office flood damage and IT repairs.

Net G&A costs for the year ended December 31, 2020 were lower compared to the same period in 2019, due to CEWS support payments received during Q4/20 and Q3/20.

On a per boe basis, excluding the effects of the CEWS, net G&A costs for the three months and year ended December 31, 2020 were higher than the same periods in 2019 due to lower overall production levels.

Stock-Based Compensation Expense

Quarter-over-Quarter			
($ thousands, except per boe)	**Q4 2020**	Q3 2020	% change
Gross costs	**$1,596**	$1,729	(8)
Capitalized costs	**(182)**	(189)	(4)
Expensed stock-based compensation	**$1,414**	$1,540	(8)
Total ($/boe)	**$0.70**	$0.78	(10)

Stock-based compensation expense related to stock options (“Options”), restricted share units (“RSUs”) and performance share units (“PSUs”) remained consistent quarter-over-quarter.

Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

Year-over-Year	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2020**	2019	% change	**2020**	2019	% change
Gross costs	**$1,596**	$3,594	(56)	**$6,397**	$12,073	(47)
Capitalized costs	**(182)**	(612)	(70)	**(897)**	(2,384)	(62)
Expensed stock-based compensation	**$1,414**	$2,982	(53)	**$5,500**	$9,689	(43)
Total ($/boe)	**$0.70**	$1.30	(46)	**$0.68**	$1.10	(38)

Stock-based compensation expense related to Options, RSUs and PSUs for the three months and year ended December 31, 2020 was lower compared to the same periods in 2019 due to grants being issued at a lower share price.

During the year ended December 31, 2020, the Company issued 0.6 million Options (at a weighted average exercise price of $1.13 per share), 2.0 million RSUs and 1.7 million PSUs compared to 0.4 million Options (at a weighted average exercise price of $2.57 per share), 2.5 million RSUs and 1.2 million PSUs during the same period in 2019.

Finance Expense

Quarter-over-Quarter			
($ thousands, except per boe)	**Q4 2020**	Q3 2020	% change
Interest on bank debt	**$2,478**	$2,451	1
Fees associated with credit facility renewal	**141**	1	14,000
Interest on lease liabilities	**196**	206	(5)
Unrealized loss (gain) on foreign exchange	**(2,962)**	1,350	(319)
Unrealized loss (gain) on cross-currency swap	**2,955**	(1,359)	(317)
Accretion of decommissioning obligations	**694**	599	16
Total finance expense	**$3,502**	$3,248	8
Total ($/boe)	**$1.73**	$1.64	5
Average drawings on bank debt	**$200,499**	$205,757	(3)

Finance expense was higher in Q4/20 compared to Q3/20 as a result of fees related to the credit facility renewal that occurred in Q4/20, partially offset by a reduction in average drawings on bank debt quarter-over-quarter.

Year-over-Year	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2020**	2019	% change	**2020**	2019	% change
Interest on bank debt	**$2,478**	$1,938	28	**$8,611**	$7,573	14
Fees associated with credit facility renewal	**141**	8	1,663	**673**	631	7
Interest on lease liabilities	**196**	234	(16)	**840**	1,241	(32)
Unrealized loss (gain) on foreign exchange	**(2,962)**	(2,859)	4	**1,249**	(2,859)	(144)
Unrealized loss (gain) on cross-currency swap	**2,955**	2,908	2	**(1,311)**	2,908	(145)
Accretion of decommissioning obligations	**694**	954	(27)	**2,573**	4,075	(37)
Total finance expense	**$3,502**	$3,183	10	**$12,635**	$13,569	(7)
Total ($/boe)	**$1.73**	$1.39	24	**$1.57**	$1.54	2
Average drawings on bank debt	**$200,499**	$198,887	1	**$203,925**	$187,575	9

Total finance expense for the three months ended December 31, 2020 was higher than the same period in 2019 as a result of higher average drawings on bank debt and increased borrowing rates related to the bank renewal in June 2020, partially offset by the lower interest on lease liabilities and accretion expense.

Total finance expense for the year ended December 31, 2020 was lower than the same period in 2019 as a result of lower interest on lease liabilities and accretion expense, partially offset by higher average drawings on bank debt and increased borrowing rates related to the bank renewal in June 2020.

Depletion, Depreciation and Amortization ("DD&A")

Quarter-over-Quarter			
($ thousands, except per boe)	**Q4 2020**	Q3 2020	% change
Depletion and depreciation	**$26,833**	$26,656	1
Amortization of undeveloped leases	**157**	157	–
Total	**$26,990**	$26,813	1
Depletion and depreciation ($/boe)	**$13.23**	$13.46	(2)
Amortization ($/boe)	**0.08**	0.08	–
Total ($/boe)	**$13.31**	$13.54	(2)

DD&A expense per boe and on an absolute basis was similar in Q4/20 to Q3/20.

Year-over-Year	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2020**	2019	% change	**2020**	2019	% change
Depletion and depreciation	**$26,833**	$43,172	(38)	**$120,061**	$166,312	(28)
Amortization of undeveloped leases	**157**	266	(41)	**597**	999	(40)
Total	**$26,990**	$43,438	(38)	**$120,658**	$167,311	(28)
Depletion and depreciation ($/boe)	**$13.23**	$18.88	(30)	**$14.89**	$18.93	(21)
Amortization ($/boe)	**0.08**	0.12	(33)	**0.07**	0.11	(36)
Total ($/boe)	**$13.31**	$19.00	(30)	**$14.96**	$19.04	(21)

For the three months and year ended December 31, 2020, DD&A expense per boe was lower relative to the same periods in 2019. The decrease was due to the completion of the Company's December 31, 2020 reserve report which resulted in an increase in Tamarack's overall proved and probable oil and natural gas reserve base following the 2020 drilling program and the West Central Acquisition and Clearwater Acquisition; and an impairment charge taken in both Q4/19 and Q1/20. On an absolute basis, DD&A expense was lower for the three months and year ended December 31, 2020 due to both lower production and reduced DD&A expense per boe.

Impairment

An impairment charge of $18.0 million was recorded during the quarter ended December 31, 2020 as a result of a decrease in the current quantities of recoverable proved and probable oil and natural gas reserves in the Company's Penny oil cash-generating unit ("CGU"). The estimated recoverable amount of this CGU as at December 31, 2020 was based on the net present value of before tax cash flows from proved and probable oil and natural gas reserves estimated by the Company's external independent qualified reserves evaluator as at December 31, 2020 at discount rates specific to the underlying composition of reserve categories of 12% to 25% (level 3 inputs). The estimated recoverable amount of the Penny oil CGU was determined using the fair value less costs of disposal ("FVLCD") methodology. This methodology is based on what Tamarack estimates it could receive should the assets in this CGU be disposed of in the current environment taking into account lower forecasted oil and natural gas prices. The following table details the impairment. All amounts are net of decommissioning obligations:

($ millions)	Carrying Value	FVLCD	Impairment
Penny oil CGU	$80.0	$62.0	$18.0

An impairment charge of $381.0 million was recorded as at March 31, 2020 as a result of a decrease in current and forecasted oil and natural gas prices. The impairment recognized relates to the Viking oil, Cardium oil, Penny oil and minor gas CGUs. The estimated recoverable amount of these CGUs as at March 31, 2020 was based on the net present value of before tax cash flows from proved and probable oil and natural gas reserves estimated by the Company's external independent qualified reserves evaluator at December 31, 2019 and updated by the Company's internal reserves evaluator to March 31, 2020 for production, production and transportation costs, royalty costs, future development costs and forecasted oil and natural gas commodity prices as at that date at discount rates specific to the underlying composition of reserve categories of 10% to 20% (level 3 inputs). The estimated recoverable amount of the CGUs was determined using the FVLCD methodology. This methodology is based on what Tamarack estimates it could receive should the assets in these CGUs be disposed of in the current environment taking into account lower forecasted oil and natural gas prices. The following table details the impairment charge. All amounts are net of decommissioning obligations:

($ millions)	Carrying Value	FVLCD	Impairment
Viking oil CGU	$682.9	$447.9	$235.0
Cardium oil CGU	274.9	137.9	137.0
Penny oil CGU	88.4	81.4	7.0
Minor gas CGU	(9.1)	(11.1)	2.0
Total	$1,037.1	$656.1	$381.0

The impairment charge of $381.0 million was allocated to property, plant and equipment in the amount $377.6 million and $3.4 million was allocated to the right-of-use asset.

The Company has recorded an aggregate impairment charge of $399.0 million related to the Viking oil, Cardium oil, Penny oil and minor gas CGUs for the year ended December 31, 2020.

An impairment charge of $68.0 million was recorded as at December 31, 2019 as a result of a decrease in current and forecasted natural gas prices. The impairment recognized relates to the Company's Cardium oil CGU that has associated natural gas being produced with the oil and includes Mannville gas wells and a Pekisko gas unit. The estimated recoverable amount of this CGU as at December 31, 2019, net of decommissioning obligations, was estimated to be $273.7 million based on the net present value of before tax cash flows from proved and probable oil and natural gas reserves estimated by the Company's external independent qualified reserves evaluator at discount rates specific to the underlying composition of reserve categories of 10% to 20% (level 3 inputs). The estimated recoverable amount of the Cardium oil CGU was determined using the FVLCD methodology based on what Tamarack could receive for the assets in this CGU if it disposed of them in the current environment taking into account lower forecasted natural gas prices. The impairment charge of $68.0 million was allocated to property, plant and equipment in the amount $67.2 million and $0.8 million was allocated to the right-of-use asset.

Income Taxes

The Company did not incur any cash tax expense for the three months and year ended December 31, 2020 and does not expect to pay any cash tax until 2024 or later based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

The Company has incorporated the Alberta corporate income tax rate reductions enacted by the Government of Alberta for the periods from July 1, 2019 to January 1, 2022, which reduced the provincial income tax rate to 11% effective July 1, 2019 and will further reduce the rate by an additional 1% on January 1 for each of the years 2020, 2021 and 2022, bringing the rate to 8%. Effective July 1, 2020, the Government of Alberta accelerated the general corporate tax rate reduction to 8%.

For the three months and year ended December 31, 2020, a deferred income tax expense of $2.1 million and a deferred income tax recovery of $87.5 million were recognized, respectively, compared to a deferred income tax recovery of $11.5 million and $14.4 million for the same periods in 2019.

The following table outlines the Company's estimated tax pools as at December 31, 2020:

Tax Pool Category	Deduction Rate	($ millions)
Canadian exploration expense (CEE)	100%	32
Canadian development expense (CDE)	30%	268
Canadian oil and gas property expense (COGPE)	10%	221
Non-capital losses (NCL)	100%	237
Undepreciated capital cost (UCC)	25%	122
Share issue costs and other	various	1
Total		881

Adjusted Funds Flow and Net Loss

Quarter-over-Quarter			
($ thousands, except per share)	**Q4 2020**	Q3 2020	% change
Cash flow from operating activities	**$23,859**	$26,965	(12)
Abandonment expenditures	**1,271**	552	130
Changes in non-cash working capital	**3,764**	3,320	13
Adjusted funds flow	**$28,894**	$30,837	(6)
Per share - basic	**$0.13**	$0.14	(7)
Per share - diluted	**$0.13**	$0.14	(7)
Net loss	**$(18,220)**	$(5,776)	215
Per share - basic	**$(0.08)**	$(0.03)	167
Per share - diluted	**$(0.08)**	$(0.03)	167

Adjusted funds flow and cash flow from operating activities generated during Q4/20 were lower than in Q3/20 primarily due to an increase in royalty and net production and transportation expenses and a lower realized hedging gain, partially offset by an increase in revenue.

The Company recorded a net loss of $18.2 million ($0.08 per share basic and diluted) during the three months ended December 31, 2020, compared to a net loss of $5.8 million ($0.03 per share basic and diluted) during the previous quarter. The higher net loss was primarily due to an $18.0 million impairment charge taken in Q4/20 and a lower realized hedging gain, partially offset by a 12% increase in revenue.

Year-over-Year	Three months ended December 31,			Years ended December 31,		
($ thousands, except per share)	**2020**	2019	% change	**2020**	2019	% change
Cash flow from operating activities	**$23,859**	$54,623	(56)	**$125,290**	$205,231	(39)
Abandonment expenditures	**1,271**	1,717	(26)	**3,825**	3,154	21
Changes in non-cash working capital	**3,764**	(1,598)	(336)	**(6,367)**	11,049	(158)
Adjusted funds flow	**$28,894**	$54,742	(47)	**$122,748**	$219,434	(44)
Per share - basic	**$0.13**	$0.25	(48)	**$0.55**	$0.97	(43)
Per share - diluted	**$0.13**	$0.25	(48)	**$0.55**	$0.97	(43)
Net loss	**$(18,220)**	$(50,546)	(64)	**$(311,384)**	$(39,011)	698
Per share - basic	**$(0.08)**	$(0.23)	(65)	**$(1.40)**	$(0.17)	724
Per share - diluted	**$(0.08)**	$(0.23)	(65)	**$(1.40)**	$(0.17)	724

Adjusted funds flow and cash flow from operating activities for the three months and year ended December 31, 2020 were lower compared to the same periods in 2019. This was primarily due to a 34% and 42% decrease in revenue, respectively, in 2020.

The Company recorded a net loss of $18.2 million ($0.08 per share basic and diluted) during Q4/20 compared to a net loss of $50.5 million ($0.23 per share basic and diluted) in Q4/19. This was primarily due to a higher impairment charge taken in Q4/19, lower DD&A expense and a gain on disposition of property, plant and equipment, partially offset by a 34% decrease in revenue, a higher unrealized hedging loss in Q4/20 and a realized hedging gain in Q4/20.

The Company recorded a net loss of $311.4 million ($1.40 per share basic and diluted) during the year ended December 31, 2020, compared to a net loss of $39.0 million ($0.17 per share basic and diluted) for the same period in 2019. This was primarily due to a 42% decrease in revenue, a $399.0 million impairment charge taken in 2020, partially offset by a realized hedging gain in 2020, a lower unrealized hedging loss in 2020, higher deferred income tax recovery and lower DD&A expense.

Capital Expenditures (Including Exploration and Evaluation Expenditures)

The following table summarizes capital spending, excluding non–cash items:

Year-over-Year	Three months ended December 31,			Years ended December 31,		
($ thousands)	**2020**	2019	% change	**2020**	2019	% change
Land	**$40**	$1,090	(96)	**$3,385**	$1,603	111
Geological and geophysical	**71**	74	(4)	**85**	198	(57)
Drilling and completion	**9,319**	16,251	(43)	**72,936**	129,344	(44)
Equipment and facilities	**2,697**	4,646	(42)	**23,553**	44,378	(47)
Capitalized G&A	**900**	807	12	**3,300**	3,033	9
Office equipment	**61**	86	(29)	**284**	410	(31)
Total capital expenditures	**$13,088**	$22,954	(43)	**$103,543**	$178,966	(42)

During the fourth quarter of 2020, the Company drilled, completed and equipped two (2.0 net) Cardium oil wells, two (2.0 net) Viking oil wells, one (0.8 net) Viking gas well and one (1.0 net) Clearwater oil well.

For the year ended December 31, 2020 Drilling Summary		
	Gross	Net
Viking	58.0	56.6
Cardium	6.0	5.3
Water source and injectors	5.0	5.0
Penny	2.0	2.0
Clearwater	1.0	1.0
	72.0	69.9

As at December 31, 2020, the Company's net undeveloped land totaled 618,887 acres.

Property Acquisitions and Disposition

On December 21, 2020, the Company completed two concurrent acquisitions of certain oil and gas properties located in the Greater Nipisi area of Alberta from two separate unrelated parties. The assets include approximately 2,000 bbls/d of crude oil production in the Clearwater oil play supported by a high-quality oil drilling inventory and approximately 107,000 net acres of land, acquired for total cash consideration of $94.9 million.

The first acquisition consisted of 1,000 bbls/d of crude oil production in the Clearwater oil play supported by a high-quality oil drilling inventory and approximately 40,660 net acres of land, acquired for total cash consideration of $53.9 million (inclusive of $1.1 million of capitalized transaction costs).

The amounts recognized on the date of acquisition of the identifiable net assets were as follows:

($ thousands)	Amount
Net assets acquired:	
Oil and natural gas interests	$ 51,389
Assets held for sale	2,759
Decommissioning obligations	(274)
Net assets acquired	**$ 53,874**
Purchase consideration:	
Cash	$ 53,874
Total purchase consideration	**$ 53,874**

The second acquisition consisted of 1,000 bbls/d of crude oil production in the Clearwater oil play supported by a high-quality oil drilling inventory and approximately 66,340 net acres of land, acquired for total cash consideration of $41.0 million (inclusive of $1.3 million of capitalized transaction costs).

The amounts recognized on the date of acquisition of the identifiable net assets were as follows:

($ thousands)	Amount
Net assets acquired:	
Oil and natural gas interests	$ 39,219
Assets held for sale	2,101
Decommissioning obligations	(282)
Net assets acquired	**$ 41,038**
Purchase consideration:	
Cash	$ 41,038
Total purchase consideration	**$ 41,038**

On December 23, 2020, the Company completed the disposition of a 2% GORR on a select portion of the Clearwater properties, committing $80.0 million of capital to further develop the GORR lands prior to December 31, 2022. The GORR disposition proceeds were $15.5 million and the Company recorded a gain on disposition of $10.7 million.

On July 9, 2020, the Company completed the acquisition of certain light oil and liquids rich natural gas properties located in West Central Alberta. The assets include approximately 2,500 boe/d (52% oil and NGL) of low-decline production supported by a high-quality, multi-zone light oil and liquids rich natural gas drilling inventory and approximately 105,000 net acres of land, acquired for total cash consideration of $4.0 million.

The amounts recognized on the date of acquisition of the identifiable net assets were as follows:

($ thousands)	Amount
Net assets acquired:	
Oil and natural gas interests	$ 20,845
Decommissioning obligations	(16,832)
Net assets acquired	**$ 4,013**
Purchase consideration:	
Cash	$ 4,013
Total purchase consideration	**$ 4,013**

Share Capital

(thousands)	**December 31, 2020**	March 1, 2021	December 31, 2019
Common shares outstanding	**262,776**	263,015	222,793
Common shares held in treasury	**747**	508	469
Options outstanding	**1,904**	1,904	2,193
RSUs outstanding	**5,365**	5,184	6,987
PSUs outstanding	**3,564**	3,483	2,157

At December 31, 2020, Tamarack Acquisition Corp. had 740,307 preferred shares (“TAC Preferred Shares”) issued and outstanding (December 31, 2019 – 1,021,974). The TAC Preferred Shares were fully vested and exchangeable into 711,834 Common Shares (December 31, 2019 – 982,667) of Tamarack at an exchange price of $3.12 per Common Share.

As noted under "Liquidity and Capital Resources" below, during the year ended December 31, 2020, Tamarack purchased and cancelled 664,100 outstanding Common Shares under our normal course issuer bid ("NCIB") program, for $1.3 million. The NCIB expired in Q2/20 and was not renewed. During the year ended December 31, 2019, Tamarack purchased and cancelled 4,181,000 outstanding Common Shares under our NCIB program, for $8.3 million.

On December 21, 2020, the Company issued 40.9 million common shares, at $1.15 per share for total gross proceeds of $47.1 million, in conjunction with the Clearwater Acquisition previously described.

Liquidity and Capital Resources

($ thousands)	**December 31, 2020**	December 31, 2019	September 30, 2020
Working capital deficiency (surplus)	**$8,454**	$(3,426)	$567
Bank debt	**210,857**	192,907	198,994
Net debt	**219,311**	189,481	199,561
Quarterly adjusted funds flow	**$28,894**	$54,742	$30,837
Annualized factor	**4**	4	4
Annualized adjusted funds flow	**115,576**	218,968	123,348
Net debt to annualized adjusted funds flow	**1.9x**	0.9x	1.6x

Tamarack's net debt (see "Non-IFRS Measures"), including working capital deficiency (surplus) (see "Non-IFRS Measures"), totaled $219.3 million as at December 31, 2020. This compares to the Company's net debt of $199.6 million in Q3/20 and $189.5 million in Q4/19. Tamarack's Q4/20 net debt to annualized adjusted funds flow ratio (see "Non-IFRS Measures") was 1.9 times as the Company carried out the Clearwater Acquisition in December 2020. The Company's forecasted plan is the reduce the ratio to 1.5x by the end of Q2/21.

The Company's $107.8 million investment in capital additions and acquisitions during Q4/20 was funded by net proceeds of a share issuance of $45.5 million, the sale of a royalty interest of $15.5 million, Tamarack's adjusted funds flow (see "Non-IFRS Measures") of $28.9 million and an increase of net debt of $17.9 million.

With continued commodity price volatility, Tamarack's strategy remains focused on preserving balance sheet strength. The Company strives to achieve this by adjusting capital spending as appropriate to respond to changes in realized commodity prices and by using financial derivatives and physical delivery contracts to mitigate risk. At times, management believes the Company's prevailing share price does not adequately reflect the underlying value of Tamarack's assets. As such, we may utilize an NCIB program through the facilities of the Toronto Stock Exchange and alternate trading platforms, pursuant to which the Company has the option to purchase our Common Shares for cancellation, thereby reducing the total number of shares outstanding. Given the volatility and depressed commodity price environment, the Company suspended the NCIB program during the second quarter to conserve working capital until commodity prices improve.

For the year ended December 31, 2020, the Company spent $1.3 million to purchase and cancel 664,100 outstanding Common Shares under the NCIB program. This is consistent with the previously published Q1/20 results as the Company did not make any additional purchases during Q2/20, Q3/20 and Q4/20. The Company also directed $3.9 million to purchase 3,641,000 issued and outstanding Common Shares in the open market. Once purchased, these Common Shares are held in trust by Tamarack's trustee and used to settle RSUs upon future exercises. This practice mitigates dilution by eliminating the need to issue new Common Shares from treasury for the settlement of RSUs and PSUs. Instead, Tamarack has the ability, when needed, to draw down from the remaining balance of purchased Common Shares that are held in trust to settle RSU exercises, further supporting Tamarack's per share metrics. At December 31, 2020, the remaining balance of purchased Common Shares held in trust totaled 746,742.

Bank Debt

Tamarack currently has available a revolving credit facility in the amount of $255 million and an operating facility of $20 million (collectively, the "Facility") with a syndicate of lenders. The Facility totals $275 million, of which $210.9 million was drawn as of December 31, 2020 (December 31, 2019 – $192.9 million), lasts for a 183-day period and will be subject to its next extension by June 30, 2021. If not extended by June 30, 2021, the Facility will cease to revolve and all outstanding balances will become repayable one year from that date.

The total interest rate on the Facility is determined through a pricing grid that categorizes based on both a total amount drawn and a net debt-to-cash-flow ratio as defined in the Facility. The interest rate will vary depending on: the lending vehicle employed; total loan value drawn; and the Company's current net debt-to-cash-flow ratio. Interest on bankers' acceptances ("BA") will vary based on a BA pricing grid from a low of the banks' posted rates plus 3.00% to a high of the banks' posted rates plus 7.00%. Interest on LIBOR Based Loans ("LIBOR") will vary based on a LIBOR pricing grid from a low of the banks' posted rates plus 3.25% to a high of the banks' posted rates plus 7.25%. Interest on prime lending varies based on a prime rate pricing grid from a low of the banks' prime rates plus 2.00% to a high of the banks' prime rates plus 6.00% with a 0.25% premium for amounts drawn in US funds. The standby fee for the Facility will vary as per a pricing grid from a low of 0.75% to a high of 1.75% on the undrawn portion of the Facility. The lending vehicles that Tamarack employs will vary from time to time based on capital needs and current market rates. As at December 31, 2020, the Facility was secured by a $1.0 billion supplemental debenture with a floating charge over all assets. As the available lending limits of the Facility are based on the lenders' interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next review by the syndicate of lenders is scheduled to be completed by June 30, 2021.

There are no financial covenants governing the Facility.

Commitments

The following table summarizes the Company's commitments as at December 31, 2020:

($ thousands)	2021	2022	2023	2024	2025+
Bank debt(1)	–	210,857	–	–	–
Lease(2)	131	174	174	174	131
Take or pay commitments(3)	3,950	4,023	3,894	–	–
Gas transportation(4)	2,293	1,627	535	143	7
Capital commitments(5)	25,000	55,000	–	–	–
Total	31,374	271,681	4,603	317	138

(1) If not extended by June 30, 2021, the Facility will cease to revolve and all outstanding balances will become repayable June 30, 2022.

(2) Relates to the variable operating costs of the Company's head office lease which are a non-lease component of lease liabilities. A new head office lease is effective from April 1, 2021 to September 30, 2025. At lease commencement the Company will recognize an estimated lease liability and right-of-use asset of $1.7 million.

(3) Pipeline commitments to deliver a minimum of 636 m^3/d of crude oil/condensate and 455 m3/d of crude oil subject to a take-or-pay provision of $9.00/$m^3$ and $9.70/$m^{3,}$ respectively, escalating approximately 2% per annum. The terms start on January 1, 2019 and last for 60 months.

(4) Gas transportation costs on long term firm contracts which are in various locations at variable rates.

(5) Commitment of $80.0 million of capital to further develop the 2% GORR Clearwater lands prior to December 31, 2022.

Contingency

During 2019, the Company was served with a Statement of Claim from two joint interest owners that hold minority interests in a Unit, which is majority owned and operated by the Company. The plaintiffs are seeking judgment in the amount of $56.0 million for unlawful conversion of their minority Unit interests (such amount based upon the alleged value of their minority Unit interests) or alternatively, judgment in the amount of $1.65 million, representing the amounts allegedly owed by the Company plus punitive damages, interest and other costs. The minority Unit owners have also alleged Tamarack has breached the Company's fiduciary duties owing to the minority Unit owners and that without the approval of the minority Unit owners, the Company has conducted operations within the Unit area and outside of the Unit area without the approval of the minority Unit owners.

The Company has filed a Statement of Defence denying all material allegations of the minority Unit owners. The Company believes the claims are without merit and the amounts are unsubstantiated. Therefore, no provision for any amount has been recorded in the consolidated financial statements.

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 on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion complies with the 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.

Abbreviations

AECO	Natural gas storage facility located at Suffield, AB
bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
CGU	cash-generating unit
DTH	dekatherm
GJ	gigajoule
IFRS	International Financial Reporting Standards
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbtu	one million British thermal units
NGL	natural gas liquids
WCS	Western Canadian Select
WTI	West Texas Intermediate

Non–IFRS Measures

This document contains the terms "adjusted funds flow", "operating netback", "operating field netback", "net debt", "net debt to annualized adjusted funds flow ratio" and "free adjusted funds flow" which are non-IFRS financial measures. The Company uses these measures to help evaluate Tamarack's performance. 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.

(a) **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. The calculation of the Company's adjusted funds flows is summarized starting on page 15 in the section titled "Adjusted Funds Flow and Net Loss".

(b) **Operating Netback and Operating Field Netback** - Management uses certain industry benchmarks, such as operating netback and operating field netback, to analyze financial and operating performance. Operating netback equals total petroleum and natural gas sales, including realized gains and losses on commodity, foreign exchange and interest rate derivative contracts, less royalties and net production and transportation costs and can also be calculated on a per boe basis. Operating field netback equals total petroleum and natural gas sales, less royalties and net production and transportation expenses. These metrics can also be calculated on a per boe basis. 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. The calculation of the Company's netbacks can be seen starting on page 9 in the section titled "Operating Netback".

(c) **Net Debt and Working Capital Deficiency (Surplus)-** Tamarack closely monitors our capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of our capital structure. The Company uses net debt (bank debt plus working capital surplus or deficiency, including the fair value of cross-currency swaps and excluding the current portion of the fair value of financial instruments, decommissioning obligations and lease liabilities) as an alternative measure of outstanding debt. Management considers net debt an important measure to assist in assessing the liquidity of the Company.

The following outlines the Company's calculation of net debt:

($ thousands)	**December 31, 2020**	December 31, 2019
Accounts payable and accrued liabilities	**$38,903**	$37,809
Cross currency swap liability	**1,597**	2,908
Accounts receivable	**(30,781)**	(42,219)
Prepaid expenses and deposits	**(1,265)**	(1,924)
Working capital deficiency (surplus)	**8,454**	(3,426)
Bank debt	**210,857**	192,907
Net debt	**$219,311**	$189,481

(d) **Net Debt to Annualized Adjusted Funds Flow** – Management uses certain industry benchmarks, such as net debt to annualized adjusted funds flow, to analyze financial and operating performance. This benchmark is calculated as net debt divided by the annualized adjusted funds flow for the most recently completed quarter. Management considers net debt to annualized adjusted funds flow as a key measure as it provides a snapshot of the overall financial health of the Company and our ability to pay off debt and take on new debt, if necessary, using the most recent quarter's results.

(e) **Free Adjusted Funds Flow –** Management uses certain industry benchmarks, such as free adjusted funds flow, to analyze financial and operating performance. This benchmark 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.

Selected Quarterly Information

Three months ended	**Dec. 31, 2020**	Sep. 30, 2020	Jun. 30, 2020	Mar. 31, 2020	Dec. 31, 2019	Sep. 30, 2019	Jun. 30, 2019	Mar. 31, 2019
Sales volumes								
Natural gas *(mcf/d)*	**53,738**	53,420	49,610	52,912	54,462	55,224	53,451	50,576
Oil and NGL *(bbls/d)*	**13,093**	12,630	12,729	14,712	15,782	14,967	15,181	14,720
Average boe/d *(6:1)*	**22,049**	21,533	20,997	23,531	24,859	24,171	24,090	23,149
Product prices								
Natural gas *($/mcf)*	**2.46**	1.61	1.37	1.61	2.26	1.54	1.71	2.82
Oil and NGL *($/bbl)*	**43.22**	42.69	23.40	43.41	59.51	59.38	65.46	62.07
Oil equivalent *($/boe)*	**31.67**	29.02	17.42	30.76	42.72	40.28	45.04	45.62
(000s, except per share amounts)								
Financial results								
Gross revenues	**64,238**	57,491	33,295	65,872	97,699	89,579	98,741	95,047
Cash provided by operating activities	**23,859**	26,965	28,107	46,359	54,623	42,199	60,320	48,089
Adjusted funds flow (1)	**28,894**	30,837	20,972	42,045	54,742	49,283	57,906	57,503
Per share – basic	**0.13**	0.14	0.09	0.19	0.25	0.22	0.26	0.25
Per share – diluted	**0.13**	0.14	0.09	0.19	0.25	0.22	0.25	0.25
Net income (loss)	**(18,220)**	(5,776)	(36,067)	(251,321)	(50,546)	(111)	16,472	(4,826)
Per share – basic	**(0.08)**	(0.03)	(0.16)	(1.13)	(0.23)	(0.00)	0.07	(0.02)
Per share – diluted	**(0.08)**	(0.03)	(0.16)	(1.13)	(0.23)	(0.00)	0.07	(0.02)
Capital expenditures	**13,088**	10,364	6,218	73,873	22,954	58,867	25,902	71,243
Acquisitions	**94,684**	4,127	–	–	250	3,847	4,771	1,074
Dispositions	**(15,525)**	–	–	–	–	–	–	–
Total assets	**1,027,600**	963,220	935,892	984,045	1,247,119	1,369,918	1,336,323	1,349,508
Net debt(1)	**219,311**	199,561	213,066	227,151	189,481	213,140	195,892	219,348
Bank debt	**210,857**	198,994	206,467	209,423	192,907	198,971	186,912	189,427
Decommissioning obligations	**245,437**	241,047	198,485	186,816	184,846	222,684	218,950	210,198

(1) Refer to definition of adjusted funds flow and net debt under "Non-IFRS Measures".

Significant factors and trends that have impacted the Company's results during the above periods include:

- The volatility in commodity prices and oil price differentials and the resulting effect on revenue, cash provided by operating activities, adjusted funds flows and earnings.
- The volatility in decommissioning obligations due to fluctuations in discount rates and acquisitions.
- The Company uses derivative contracts to reduce the financial impact of volatile commodity prices, foreign exchange and interest rates which can cause significant fluctuations in earnings due to unrealized gains and losses recognized on a quarterly basis.
- On December 21, 2020, the Company completed two acquisitions of certain oil properties located in the Greater Nipisi area of Alberta. The assets include approximately 2,000 bbls/d of crude oil

production in the Clearwater oil play supported by a high-quality oil drilling inventory and approximately 107,000 net acres of land, acquired for total cash consideration of $94.9 million.

- On July 9, 2020, the Company completed the acquisition of certain light oil and liquids rich natural gas properties located in West Central Alberta. The assets include approximately 2,500 boe/d (52% oil and NGL) of production supported by a high-quality, multi-zone light oil and liquids rich natural gas drilling inventory and approximately 105,000 net acres of land, acquired for total cash consideration of $4.0 million.
- The Company recorded an impairment charge in Q4/20 in the amount of $18.0 million on our Penny oil CGU due to a reduction in the current quantities of recoverable proved and probable oil and natural gas reserves.
- The Company recorded an impairment charge in Q1/20 in the amount of $381.0 million on our CGUs due to decreased current and forecasted oil and natural gas prices. The impairment charge was recorded in the following CGUs: the Viking oil CGU was impaired $235.0 million, the Cardium oil CGU was impaired $137.0 million, the Penny oil CGU was impaired $7.0 million and the minor gas CGU was impaired $2.0 million.
- The Company recorded an impairment charge in Q4/19 in the amount of $68.0 million on its Cardium oil CGU due to decreased current and forecasted natural gas prices as that CGU has associated natural gas produced with the oil and includes Mannville gas wells and a Pekisko gas unit.

Selected Annual Information

	2020	2019	2018 [(2)]
Sales volumes			
Natural gas *(mcf/d)*	**52,426**	53,444	51,108
Oil and NGL *(bbls/d)*	**13,289**	15,165	15,719
Average boe/d *(6:1)*	**22,027**	24,072	24,237
Product prices			
Natural gas *($/mcf)*	**1.77**	2.06	2.30
Oil and NGL *($/bbl)*	**38.42**	61.58	62.02
Oil equivalent *($/boe)*	**27.40**	43.37	45.08
(000s, except per share amounts)			
Financial Results			
Gross revenues	**220,896**	381,066	398,804
Net income (loss)	**(311,384)**	(39,011)	38,310
Per share – basic	**(1.40)**	(0.17)	0.17
Per share – diluted	**(1.40)**	(0.17)	0.16
Capital expenditures	**103,543**	178,966	226,251
Acquisitions	**98,811**	9,942	2,847
Dispositions	**(15,525)**	–	(9,889)
Total assets	**1,027,600**	1,247,119	1,264,053
Net debt[(1)]	**219,311**	189,481	179,880
Bank debt	**210,857**	192,907	161,495

(1) Refer to definition of net debt under “Non-IFRS Measures”.

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

Significant factors and trends that have impacted the Company’s results during the above periods include:

- The volatility in commodity prices and the resultant effect on revenue and earnings.
- The Company uses derivative contracts to reduce the financial impact of volatile commodity prices and foreign exchange and interest rates which can cause significant fluctuations in earnings due to unrealized gains and losses recognized on a quarterly basis.
- On December 21, 2020, the Company completed two acquisitions of certain oil properties located in the Greater Nipisi area of Alberta. The assets include approximately 2,000 bbls/d of crude oil production in the Clearwater oil play supported by a high-quality oil drilling inventory and approximately 107,000 net acres of land, acquired for total cash consideration of $94.9 million.
- On July 9, 2020, the Company completed the acquisition of certain light oil and liquids rich natural gas properties located in West Central Alberta. The assets include approximately 2,500 boe/d (52% oil and NGL) of production supported by a high-quality, multi-zone light oil and liquids rich natural gas drilling inventory and approximately 105,000 net acres of land, acquired for total cash consideration of $4.0 million.
- The Company recorded an impairment charge in Q4/20 in the amount of $18.0 million on our Penny oil CGU due to a reduction in the current quantities of recoverable proved and probable oil and natural gas reserves.
- The Company recorded an impairment charge in Q1/20 in the amount of $381.0 million on our CGUs due to decreased current and forecasted oil and natural gas prices. The impairment charge was recorded in the following CGUs: the Viking oil CGU was impaired $235.0 million, the Cardium oil CGU was impaired $137.0 million, the Penny oil CGU was impaired $7.0 million and the minor gas CGU was impaired $2.0 million.
- In Q4/19, the Company recorded an impairment charge on its Cardium oil CGU that has associated natural gas being produced with the oil and includes Mannville gas wells and a Pekisko gas unit, due to decreased current and forecasted natural gas prices in the amount of $68.0 million.
- In Q4/18, the Company recorded an impairment charge on its Cardium oil CGU, due to decreased current and forecasted natural gas prices in the amount of $58.0 million and an impairment reversal of $53.0 million on its Viking oil CGU for a net impairment charge of $5.0 million.

Critical Accounting Estimates

Management is required to make judgments, assumptions, and estimates in applying its accounting policies which have significant impact on the financial results of the Company. The following outlines the accounting policies involving the use of estimates that are critical to understanding the financial condition and results of operations of the Company:

(a) **Oil and natural gas reserves** – Proved reserves, as defined by the Canadian Securities Administrators in NI 51-101 with reference to the Canadian Oil and Gas Evaluation Handbook, are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved and probable reserves.

(b) **Carrying value of property, plant and equipment ("PP&E")** – PP&E is measured at cost less accumulated depletion, depreciation, amortization and impairment losses. The net carrying value of PP&E and estimated future development costs is depleted using the unit-of-production method based on estimated proved and probable oil and natural gas reserves. Changes in estimated proved and probable oil and natural gas reserves or future development costs have a direct impact on the calculation of depletion expense.

The Company is required to use judgment when designating the nature of oil and gas activities as exploration and evaluation ("E&E") assets or development and production assets within PP&E. E&E assets and development and production assets are aggregated into CGUs based on their ability to generate largely independent cash inflows. The allocation of the Company's assets into CGUs requires significant judgment with respect to the use of shared infrastructure, geographic proximity, existence of active markets for the Company's products, the way in which management monitors operations and materiality.

Significant management judgments are required to analyze the relevant external and internal indicators of impairment or impairment reversal for a CGU with the estimate of proved and probable oil and natural gas reserves and the related cash flows being significant to the assessment.

The Company assesses PP&E for impairment or impairment reversal whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. If any such indication of impairment or impairment reversal exists, the Company performs an impairment test related to the specific CGU. The determination of the estimated recoverable amount of a CGU is based on estimates of proved and probable oil and natural gas reserves and the related cash flows. By their nature, these estimates of proved and probable oil and natural gas reserves and the related cash flows are subject to uncertainty including significant assumptions related to forecasted oil and natural gas commodity prices, forecasted production, forecasted production and transportation costs, forecasted royalty costs and forecasted future development costs and the impact on the financial statements of future periods could be material.

(c) **Decommissioning obligations –** The decommissioning obligations are estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a risk-free rate. The costs are included in PP&E and amortized over the useful life of the asset. The liability is adjusted each reporting period to reflect the passage of time, with the accretion expense charged to net earnings, and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements could be material.

(d) **Income taxes** – The determination of income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

Changes in Accounting Standards

IFRS 3 "Business Combinations"

In October 2018, the IASB issued amendments to the definition of a business in IFRS 3 - "Business Combinations". The amendments are intended to assist entities to determine whether a transaction should be accounted for as a business combination or as an asset acquisition. IFRS 3 continues to adopt a market participant's perspective to determine whether an acquired set of activities and assets is a business. The amendments clarify the minimum requirements for a business; remove the assessment of whether market participants are capable of replacing any missing elements; add guidance to help entities assess whether an acquired process is substantive; narrow the definitions of a business and of outputs; and introduce an optional fair value concentration test. The concentration test is a simplified assessment that results in an asset acquisition if substantially all of the fair value of the gross assets is concentrated in a single identifiable asset or a group of similar identifiable assets. If an entity chooses not to apply the concentration test, or the test is failed, then the assessment focuses on the existence of a substantive process.

The amendments to IFRS 3 are effective for annual reporting periods beginning on or after January 1, 2020 and apply prospectively.

IAS 20 "Accounting for Government Grants and Disclosure of Government Assistance"

The Company applied IAS 20 "Accounting for Government Grants and Disclosure of Government Assistance" in relation to receiving the Canada Emergency Wage Subsidy ("CEWS") as part of the federal government of Canada's response to the COVID-19 health pandemic, as well as the Alberta Site Restoration Program ("SRP") and the Saskatchewan Accelerated Site Closure Program ("ASCP"). Government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attached to them and the grants will be received. Grants that compensate the Company for expenses incurred are recognized as a reduction to the related expense on a systematic basis in the periods in which the expenses are recognized. When the conditions of a grant relate to an underlying obligation, it is recognized as a reduction to the obligation and recognized in profit or loss when the conditions of the grant have been met and the receipt of the grant is reasonably assured.

Disclosure Controls and Internal Controls over Financial Reporting

The Company has designed disclosure controls and procedures ("DCP") to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in our annual filings, interim filings or other reports filed or submitted under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company has designed internal controls over financial reporting ("ICFR") to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's ICFR that occurred during the recent fiscal period that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

The Company established procedures for remote working and opened the corporate head office on a limited and intermittent basis during the year. Working from home required certain processes and controls that were previously done or documented manually to be completed and retained in electronic form. The changes required by the current environment resulted in no significant changes in the Company's internal controls during the period ended December 31, 2020 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. As a result, the Company's DCP and ICFR were effective as at December 31, 2020.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met, and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Business Risks

Tamarack faces business risks, both known and unknown, with respect to its oil and gas exploration, development, and production activities that could cause actual results or events to differ materially from those forecasts. Most of these risks (financial, operational or regulatory) are not within the Company's control. While the following sections discuss some of these risks, they should not be construed as exhaustive. For additional information on the risks relating to Tamarack's business, see "Risk Factors" in Tamarack's Annual Information Form for the year ended December 31, 2020, which can be found on SEDAR at www.sedar.com.

(a) Impact of the COVID-19 Pandemic

Tamarack's business, financial condition and results of operations could be materially and adversely affected by the outbreak of epidemics, pandemics and other public health crises in geographic areas in which it has operations, suppliers, customers or employees, including the global outbreak of COVID-19. The COVID-19 pandemic, given its severity, scale, duration and rapid evolution, and actions that may be taken by governmental authorities in response thereto, has resulted, and may continue to result in, among other things: increased volatility in financial markets and foreign currency exchange rates; disruptions to global supply chains; labour shortages; reductions in trade volumes; temporary operational restrictions and restrictions on gatherings greater than a certain number of individuals, shelter in place declarations and quarantine orders, business closures and travel bans; an overall slowdown in the global economy; political and economic instability; and civil unrest. In particular, the COVID-19 pandemic has resulted in, and may continue to result in, a reduction in the demand for, and prices of, commodities that are closely linked to Tamarack's financial performance, including oil, natural gas and NGL, and also increases the risk that storage for oil could reach capacity in certain geographic locations in which Tamarack operates. A prolonged period of decreased demand for, and prices of, these commodities, and any applicable storage constraints, has resulted in, and may continue to result in, the Company shutting-in production, which could adversely impact the Company's business, financial condition and results of operations.

The Company is also subject to risks relating to the health and safety of its personnel, as well as the potential for a slowdown or temporary suspension of its operations in locations impacted by an outbreak, increased labour and fuel costs and regulatory changes. Tamarack has implemented health and safety measures at Tamarack's facilities and offices to limit the risk of transmission of COVID-19. Additionally, Tamarack follows posted health guidelines, as and when posted, to protect the health of its employees and decrease the potential impact of serious illness, including COVID-19, on its operations. However, should an employee of, or visitor to, any of Tamarack's facilities or offices become infected with COVID-19, it could place Tamarack's entire workforce at risk, which could result in the suspension of operations at one or more of Tamarack's facilities. Such a suspension in operations could also be mandated by governmental authorities in response to the COVID-19 pandemic. This would negatively impact Tamarack's production for a sustained period of time, which could adversely impact its business, financial condition and results of operations.

In addition, the disruption and volatility in global capital markets that has resulted, and may continue to result, from the COVID-19 pandemic could increase the Company's cost of capital and adversely affect the Company's ability to access the capital markets on a timely basis, or at all.

The COVID-19 pandemic continues to rapidly evolve and the full impact on the Company's business, financial condition and results of operations, as well as the Company's future capital expenditures and other discretionary items, will depend on future developments, which are highly uncertain and cannot be predicted with any degree of confidence, including: the geographic spread of the virus; the duration and extent of the pandemic, the spread of new variant strains of the virus, further actions that may be taken by governmental authorities, including in respect of travel restrictions and business disruptions; the severity of the disease; and the effectiveness of actions taken to contain the virus and treat the disease, including access to effective vaccines. To the extent that the COVID-19 pandemic continues to adversely affects Tamarack's business, financial condition and results of operations, it may also have the effect of heightening many of the other risks described in this MD&A and Tamarack's Annual Information Form for the year ended December 31, 2020.

(b) **Continued Volatility in Commodity and Petroleum Products Prices**

Market events and conditions, including global excess oil, natural gas and petroleum product supply as a result of actions taken by OPEC and non-OPEC oil and gas exporting countries to set and maintain increased production levels and influence oil prices and decreased global demand due to the COVID-19 pandemic caused significant weakness and volatility in commodity and petroleum product prices during the first half of 2020 and corresponding reductions in industry capital and operating budgets. With the rapid spread of the COVID-19 pandemic and additional crude oil supply expected to come on-stream over the near term, the price of oil and other petroleum products deteriorated significantly in the first half of 2020 and remained under pressure with increased volatility throughout 2020 and is expected to continue to exhibit increased volatility. The overall result of these events and conditions could lead to a prolonged period of volatile prices for oil and other petroleum products. Similar to the risks and uncertainties outlined above under "Impact of the COVID-19 Pandemic", this could result in reduced utilization and/or the suspension of operations at certain of the Company's facilities, buyers of the Company's products declaring force majeure and disruptions of pipeline and other transportation systems for the Company's products, which would further negatively impact Tamarack's production, and could adversely impact Tamarack's business, financial condition and results of operations.

These events and conditions in the first half of 2020 also caused significant decreases in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in western Canada has led to additional downward price pressure on oil and natural gas produced in western Canada. The overall impact of these current market conditions and the lack of confidence in the Canadian crude oil and natural gas industry could materially and adversely affect Tamarack's business, prospects, financial condition, results of operations and cash flows.

Financial Risks

Financial risks include commodity pricing, exchange and interest rates and volatile markets.

Commodity price fluctuations result from market forces completely out of the Company's control and can significantly affect the Company's financial results. In addition, fluctuations between the Canadian dollar and the US dollar can also have a significant impact. Expenses are all incurred in Canadian dollars while oil, and to some extent natural gas, prices are based on reference prices denominated in US dollars. Due to both of these factors, Tamarack may enter into derivative instruments to partially mitigate the effects of downward price and foreign exchange volatility. To evaluate the need for hedging, management, with direction from the Board of Directors, monitors future pricing trends together with the cash flow necessary to fulfill capital expenditure requirements. Tamarack will only enter into a hedge to reduce downside uncertainty of pricing, not as a speculative venture.

Operational Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Tamarack depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, existing reserves and their subsequent production will decline over time as they are exploited. A future increase in Tamarack's reserves will depend not only on its ability to explore and develop any properties it may have, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that further commercial quantities of oil and natural gas will be discovered or acquired by Tamarack.

Tamarack endeavors to mitigate these risks by, among other things, ensuring that its employees are highly qualified and motivated. Prior to initiating capital projects, the Tamarack technical team completes an economic analysis, which attempts to reflect the risks involved in successfully completing the project. In an effort to mitigate the risk of not finding new reserves, or of finding reserves that are not economically viable, Tamarack utilizes various technical tools, such as 2D and 3D seismic data, rock sample analysis and the latest drilling and completions technology.

Insurance is in place to protect against major asset destruction or business interruptions, and includes, but is not limited to, events such as well blow-outs or pollution. In addition, Tamarack cultivates relationships with its suppliers in an effort to ensure good service regardless of the prevailing cycle of oil and gas activity.

Operational risk is mitigated by having Tamarack employees address the continued development of a new or established reservoir on a go-forward basis, using the same procedure that is used to address exploration risk. The decision to produce reserves is made based on the amount of capital required, production practices and reservoir quality. Tamarack evaluates reservoir development based on the timing, amount of additional capital required and the expected change in production values. Finding and development costs are controlled when capital is employed in a cost-effective manner.

Regulatory Risks

Regulatory risks include the possibility of changes to royalty, tax, environmental and safety legislation. Tamarack endeavours to anticipate the costs related to compliance and budget sensibly for them. Changes to environmental and safety legislation may also cause delays to Tamarack's drilling plans, its production efficiencies and may adversely affect its future earnings. In December 2020, the Government of Canada proposed increasing the carbon tax to $170/tonne of carbon dioxide equivalent ("CO2e") by 2030. To reach that level, the price imposed on carbon will rise from the 2022 rate of $50/tonne of CO2e by $15/tonne of CO2e each year until 2030. If enacted into law, this may have a significant impact on Tamarack. Notably, several Canadian provinces launched constitutional challenges to Canada's national carbon-pricing regime that were heard by the Supreme Court of Canada ("SCC") in September 2020; however, as of December 31, 2020, the SCC's decision had not yet been issued. To the extent a province's carbon pricing system does not meet the federal stringency requirements, the federal "backstop" price of carbon applies. As of December 2020, the federal backstop applied in Alberta, Manitoba, New Brunswick, Ontario and to electricity generation and natural gas transmission pipelines in Saskatchewan. Restrictive new legislation is a risk the Company cannot control.

Forward-Looking Statements

Certain statements contained within this MD&A constitute forward-looking statements within the meaning of applicable Canadian securities legislation. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as “anticipate”, “budget”, “plan”, “endeavour”, “continue”, “estimate”, “evaluate”, “expect”, “forecast”, “monitor”, “may”, “will”, “can”, “able”, “potential”, “target”, “intend”, “consider”, “focus”, “identify”, “use”, “utilize”, “manage”, “maintain”, “remain”, “result”, “cultivate”, “could”, “should”, “believe”, “strive” and similar expressions or the negative of such terms or other comparable terminology. The Company believes that the expectations reflected in such forward-looking statements are reasonable, but no assurance can be given that such expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

Without limitation, this MD&A contains forward-looking statements pertaining to:

- Tamarack’s business strategy, objectives, strength and focus, including future development of the Clearwater Acquisition and the West Central Acquisition;
- the intentions of management and the Company;
- the COVID-19 pandemic, the Company’s and governmental authorities’ current and planned responses thereto and the impact thereof on, without limitation, the Company in particular and the oil and gas industry in general;
- applications and grants under the CEWS, SRP and ASCP programs;
- the Company’s commitment to the practices outlined in the Environmental, Social and Governance Sustainability Report published in Q3 2020;
- expectations relating to future realized commodity prices, volatile commodity prices and oil price differentials and the effects thereof, including with respect to revenue and earnings;
- Tamarack’s hedging program;
- Tamarack’s commitment to maintaining financial flexibility;
- Tamarack being well positioned from a liquidity standpoint;
- Committed capital spending to develop the GORR lands and timing thereof;
- uncertainty regarding the full impact of COVID-19 on global economies, oil demand and commodity prices;
- uncertainty regarding the duration and extent of oil demand destruction resulting from the COVID-19 pandemic;
- Tamarack’s exposure to diversified gas markets and the effects thereof;
- expectation relating to risk mitigation and realized price improvements from exposure to diversified gas markets;
- Tamarack’s third-party gas sales contracts that provide diversification of the Company’s natural gas price exposure and mitigate individual market volatility risk;
- Tamarack’s use of financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates;
- Tamarack’s use of commodity, foreign exchange and interest rate contracts and risk management thereof;
- expectations as to royalty rates as a percentage of revenue;
- expectations relating to the timing for paying cash tax;
- Tamarack’s strategy for preserving balance sheet strength;

- deferred tax assets, including in respect of deferred income tax;
- future RSU and PSU settlements;
- the availability, size, terms, use and renewal of the Facility;
- contractual obligations and commitments; and
- estimates used to calculate decommissioning obligations and depletion of PP&E.

With respect to the forward-looking statements contained in this MD&A, Tamarack has made assumptions regarding, among other things:

- future commodity prices, price differentials and the actual prices received for the Company's products;
- expected net production and transportation expenses;
- estimated proved and probable oil and natural gas reserves;
- the ability to obtain equipment and services in the field in a timely and efficient manner;
- the ability to add production and reserves through acquisition and/or drilling at competitive prices;
- the timing of anticipated future production additions from the Company's properties and acquisitions;
- the realization of anticipated benefits of acquisitions, including the Clearwater Acquisition and the West Central Acquisition and the related drilling programs;
- the ability to explore and realize benefits from exposure to diversified gas markets;
- drilling results, including field production rates and decline rates;
- the performance of the waterflood projects;
- the continued application of horizontal drilling and fracturing techniques and pad drilling;
- the continued availability of capital and skilled personnel;
- the ability to obtain financing on acceptable terms;
- the accuracy of Tamarack's geological interpretation of its drilling and land opportunities, including the ability of seismic activity to enhance such interpretation;
- the impact of increasing competition;
- the ability of the Company to secure adequate product transportation;
- the ability to enter into future commodity derivative contracts on acceptable terms;
- the continuation of the current tax, royalty and regulatory regime;
- the volatility in commodity prices and oil price differentials and the resulting effect on Tamarack's revenue, cash provided by operating activities, adjusted funds flows and earnings;
- the ability to adjust capital spending relative to commodity prices and use financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates;
- the ability to maintain financial flexibility;
- the ability to renew the Facility on acceptable terms; and
- Tamarack's ability to execute its plans in response to the COVID-19 pandemic.

Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated or implied by such forward-looking statements due to a number of factors and risks. These include:

- the material uncertainties and risks described under the headings “Unit Cost Calculation”, “Non-IFRS Measures”, “Critical Accounting Estimates”, “Changes in Accounting Standards”, “Disclosure Controls and Internal Controls over Financial Reporting”, “Business Risks”, “Financial Risks”, “Operational Risks” and “Regulatory Risks”;
- the material assumptions and observations described under the headings “Strategic Acquisitions”, “Q4 & Year End 2020 Financial and Operating Highlights”, “Managing Through the Novel Coronavirus (COVID-19)”, “Sustainability”, “Production”, “Petroleum and Natural Gas Sales”, “Royalties”, “Net Production and Transportation Expenses”, “Operating Netback”, “General and Administrative (“G&A”) Expenses”, “Stock-Based Compensation Expense”, “Finance Expense”, “Depletion, Depreciation and Amortization (“DD&A”)”, “Impairment”, “Income Taxes”, “Adjusted Funds Flow and Net Loss”, “Capital Expenditures (Including Exploration and Evaluation Expenditures)”, “Property Acquisitions and Disposition”, “Share Capital”, “Liquidity and Capital Resources”, “Bank Debt”, “Commitments”, “Contingency”, “Selected Quarterly Information” and “Selected Annual Information”;
- the COVID-19 pandemic and the impact on the Company’s business, financial condition and results of operations;
- the risks associated with the oil and gas industry in general, such as operational risks in development, exploration and production and including continued weakness and volatility in commodity prices and petroleum product prices;
- the actions of OPEC and non-OPEC oil and gas exporting countries to set production levels and the influence thereof on oil prices and global demand;
- delays or changes in plans with respect to exploration or development projects or capital expenditures;
- volatility in market prices for oil and natural gas;
- uncertainties associated with estimating proved and probable oil and natural gas reserves and the ability of the Company to realize value from its properties;
- geological, technical, drilling and processing problems;
- facility and pipeline capacity constraints and access to processing facilities and to markets for production;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- credit worthiness of counterparties to commodity, foreign exchange and interest rate contracts;
- marketing and transportation;
- prevailing weather and break-up conditions;
- environmental risks;
- competition for, among other things, capital, acquisition of reserves, undeveloped lands and skilled personnel;
- net production and transportation costs and future development costs;
- the ability to access sufficient capital from internal and external sources;
- the ability to renew the Facility on acceptable terms and the impact thereof;
- changes in tax, royalty and environmental legislation and any government policy; and
- any legal proceedings, the results thereof and the impact on the Company’s business, financial condition and results of operations.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. The risk factors above should be considered in the context of current economic conditions, increased supply resulting from evolving exploitation methods, the attitude of lenders and investors towards corporations in the energy industry, potential changes to royalty and taxation regimes and to environmental and other government regulations, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company. Also, to be considered are increased levels of political uncertainty and possible changes to existing international trading agreements and relationships. Legal challenges to asset ownership, limitations to rights of access and adequacy of pipelines or alternative methods of getting production to market may also have a significant effect on the Company's business. Additional information on these and other factors that could affect the business, operations or financial results of Tamarack are included in reports on file with applicable securities regulatory authorities, including but not limited to Tamarack's Annual Information Form for the year ended December 31, 2020, which may be accessed on Tamarack's SEDAR profile at www.sedar.com or on the Company's website at www.tamarackvalley.ca.

This MD&A contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Tamarack's prospective results of operations, production, free adjusted funds flow, net debt, net debt to annualized adjusted funds flow, corporate decline rates, royalty rates and components thereof, including pro forma the completion of (i) the Clearwater Acquisition, (ii) the $47.1 million private placement and (iii) the GORR disposition on a select portion of the acquired properties, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs and the assumptions outlined under "Non-IFRS Measures".

The forward-looking statements and FOFI contained in this MD&A are made as of the date hereof and Tamarack undertakes no obligation to update publicly or revise any forward-looking statements, forward-looking information or FOFI whether as a result of new information, future events or otherwise, unless so required by applicable securities laws. The forward-looking statements and FOFI contained herein are expressly qualified by this cautionary statement.