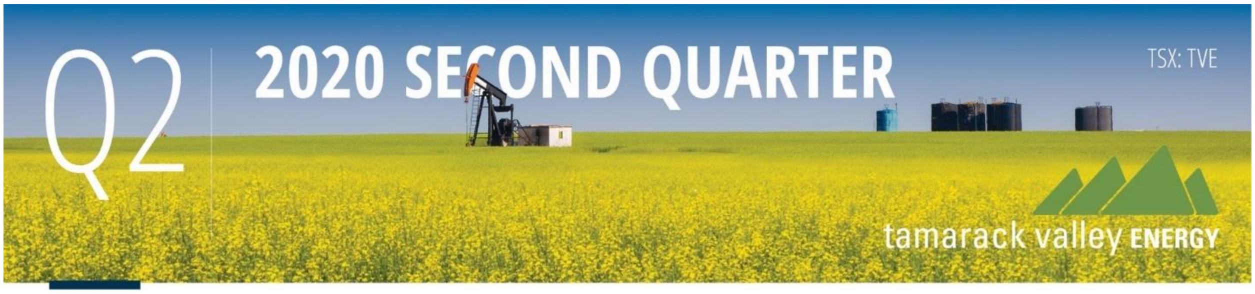

MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

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 and six months ended June 30, 2020 and 2019. This MD&A is dated and based on information available as at August 12, 2020 and should be read in conjunction with the unaudited condensed consolidated interim financial statements (“financial statements”) and the notes thereto for the three and six months ended June 30, 2020 and 2019. Additional information relating to Tamarack, including Tamarack’s Annual Information Form for the year ended December 31, 2019, is available on SEDAR at www.sedar.com and Tamarack’s website at www.tamarackvalley.ca.

The interim consolidated financial statements have been prepared in accordance with International Accounting Standards 34 “Interim Financial Reporting”. 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 18. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

Responding to Volatile Oil Prices and the Novel Coronavirus (COVID-19)

During the first quarter, the COVID-19 outbreak was declared a pandemic by the World Health Organization which resulted in governments worldwide, including those in Canada, taking measures to contain the spread of the virus. These measures reduced demand for crude oil along with other products and services which caused a significant slowdown in the global economy. Further compounding the matter was the oversupply of oil due to the supply war between major oil producing countries which resulted in West Texas Intermediate (WTI) benchmark prices falling to approximately US$20 per barrel at the end of March.

In April, OPEC+ members agreed to cut oil output in May and June along with several other countries announcing similar production cuts. The decrease in the global supply of crude oil coupled with increases in demand as governments eased measures to contain the virus, resulted in the WTI benchmark price ranging in the second quarter from a low of US$10.01 per barrel, excluding a historic one day low of negative US$37.63 per barrel, to a high of US$40.46 per barrel, closing June at US$39.27 per barrel.

Given the immense volatility, Tamarack took decisive action to protect the financial strength and enhance the sustainability of the Company which included a reduced 2020 capital investment program announced on March 18th, 2020 along with operating and general and administrative (G&A) cost reductions, which included voluntary 10% salary roll-backs for both the Board and Executives in the second quarter. Further to this, the Company elected to shut-in approximately 1,350 boe/d of production based on a multi-pronged evaluation approach that encompassed both a well-by-well and field-level cash flow analysis, along with an NPV based value preservation sensitivity. As WTI benchmark prices strengthened through the second quarter, Tamarack brought approximately half of the shut-in production on-line. The remaining shut-in volumes are related to third party infrastructure constraints, along with volumes related to maximizing the NPV of the waterflood at Veteran. In addition to the above initiatives to protect and enhance shareholder value, the Company has both WTI and differential hedges in place to protect a large portion of its oil production for the remainder of 2020.

The Provincial and Federal governments 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 continues to work towards getting assistance from the CEWS program to help protect jobs during the pandemic along with the SRP in Alberta and ASCP in Saskatchewan.

Tamarack continues its commitment to its environmental, social and governance ("ESG") principles, reflected in the Company's response to the COVID-19 crisis. This includes the phased re-opening of the corporate headquarters along with the constant assessment of risk management policies committed to the health and safety of our skilled and valued employees, as well as the public in the communities in which we operate. Strategically, the Company is advancing its broader initiatives with a dedicated team of senior members leading the development of Tamarack's targets and inaugural ESG report to integrate and enhance our accountability and sustainability moving forward.

Q2 2020 Financial and Operating Highlights

The second quarter was an extremely challenging period for the oil and gas sector given the demand destruction caused by the COVID-19 pandemic. Despite these challenges, Tamarack was able to manage our business effectively through this cycle achieving free adjusted funds flow (see "Non-IFRS Measures") for the second quarter of approximately $14.8 million representing a total payout ratio of approximately 30% (see "Non-IFRS Measures"). Average production was 20,997 boe/d in Q2/20, inclusive of shut-ins, representing a reduction of approximately 11% from Q1/20. The Company invested approximately $6.2 million in capital expenditures which included the completion of one (1.0 net) Banff oil well plus some minor Q1/20 carry-over capital costs as all other spending was put on hold due to the effects of COVID-19 on commodity prices. Tamarack's focus on cost cutting resulted in lower production and transportation expense along with G&A expense quarter-over-quarter.

The Company's second quarter operating netback of $13.75/boe generated adjusted funds flow (see "Non-IFRS Measures") of $21.0 million ($0.09 per share basic and diluted). The Company recorded a net loss of $36.1 million ($0.16 per share basic and diluted), inclusive of realized hedging gains of $16.2 million, in the quarter. Tamarack remains well hedged through the second half of 2020.

During the quarter, the Company completed its bank syndicated credit facility redetermination at $275 million. As at June 30, 2020, the Company had drawn $206.5 million against this facility. Tamarack is committed to maintaining financial flexibility and is well positioned from a liquidity standpoint.

The Company exited the quarter with net debt totaling $213.1 million, including working capital deficiency but excluding the fair value of financial instruments and lease liabilities compared to $227.2 million at the end of Q1/20. The Company has sufficient liquidity for the remainder of 2020 and expects to generate adjusted funds flow over and above planned capital expenditures with a forecasted year-end net debt to trailing annual adjusted funds flow ratio (see "Non-IFRS Measures") of less than 1.5 times at current strip prices.

Updated Guidance

On July 9, 2020 Tamarack announced a strategic asset acquisition in West Central, Alberta for total cash proceeds of $4.25 million. This included: 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 gas drilling inventory; and approximately 105,000 net acres of land. In conjunction with the acquisition, Tamarack provided updated 2020 pro-forma guidance inclusive of the curtailed production volumes brought back on-stream and the increase to the Company's reclamation and abandonment spending in 2020 representing our ongoing commitment to enhancing the Company's ESG initiatives.

Pro-Forma 2020 Updated Guidance

	July 9, 2020 Updated Guidance
Full Year Capital Budget (including Acquisitions & ARO spend) ($MM)	$101
Annual Average Production (boe/d)	20,850 - 21,250
Annual Average Oil & Natural Gas Liquids Weighting (%)	~60-62%
Free Adjusted Funds Flow(1) (Inclusive of ARO Spend) ($MM)	$15-20
Year-End Net Debt to Trailing Annual Adjusted Funds Flow Ratio(1) (times)	~1.5x
2021 Estimated Corporate Decline Rate(2)	22-24%
2021 Estimated Corporate Sustaining Capital Breakeven Price ($/Bbl)(1)	~US$37.00

(1) See Non-IFRS Measures
(2) Based on December 2020 to December 2021 estimates

This guidance is based on average 2020 commodity price assumptions of WTI US$39.00/bbl, MSW/WTI differential of US$6.00/bbl and AECO at $2.00/GJ as well as a Canadian/US dollar exchange rate of $1.3625.

Production

Quarter-over-Quarter

	Q2 2020	Q1 2020	% change
Production			
Light oil (bbls/d)	**11,107**	12,867	(14)
Heavy oil (bbls/d)	**156**	180	(13)
Natural gas liquids (bbls/d)	**1,466**	1,665	(12)
Natural gas (mcf/d)	**49,610**	52,912	(6)
Total (boe/d)	**20,997**	23,531	(11)
Percentage of oil and NGL	**61%**	63%	(3)

Average production for Q2/20 decreased 11% from the previous quarter as a result of expected declines from existing base production and the shut-in of uneconomic wells due to price declines for a portion of the quarter. This was partially offset by the Company's first quarter drilling program that added 3,234 boe/d in Veteran (84% oil and NGL weighting) and 1,434 boe/d in Wilson Creek/Alder Flats (66% oil and NGL weighting) to second quarter production.

As highlighted above, global oil prices declined considerably at the beginning of the quarter due to the reduced demand as a result of COVID-19 and the oversupply stemming from the price war between OPEC+

countries. While the OPEC+ countries reached an agreement on production cuts and global oil prices have improved, the macro environment remains volatile and considerable uncertainty exists regarding the duration and extent of oil demand destruction from the COVID-19 pandemic. Tamarack has implemented a process to assess shut-in economics for all of its production based on a multi-pronged evaluation approach that encompasses both well-by-well and field-level cash flow analysis, and incorporates an NPV-based value preservation sensitivity that is specific to the Company's new, higher decline wells and its Veteran waterflood program. The Company returned approximately half of the shut-in volumes at the end of the second quarter and will continue to evaluate the economics for adjusting production rates.

The Company's average oil and NGL weighting was 61% in Q2/20 and 63% in Q1/20.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
	2020	2019	% change	**2020**	2019	% change
Production						
Light oil (bbls/d)	**11,107**	13,237	(16)	**11,988**	12,965	(8)
Heavy oil (bbls/d)	**156**	521	(70)	**168**	502	(67)
Natural gas liquids (bbls/d)	**1,466**	1,423	3	**1,565**	1,485	5
Natural gas (mcf/d)	**49,610**	53,451	(7)	**51,261**	52,022	(1)
Total (boe/d)	**20,997**	24,090	(13)	**22,265**	23,622	(6)
Percentage of oil and NGL	**61%**	63%	(3)	**62%**	63%	(2)

Average production for Q2/20 and the first six months of 2020 decreased 13% and 6%, respectively, compared to the same periods in 2019 due to expected declines of existing base production and the effect of the COVID-19 pandemic resulting in the temporary shut-in of uneconomic wells, partially offset by the Company's 2019 and Q1/20 drilling program. The Company's oil and NGL weighting was slightly lower for Q2/20 and the first six months of 2020 relative to the same periods in 2019 due to the shut-in of oil barrels during the quarter.

Petroleum and Natural Gas Sales

Quarter-over-Quarter

	Q2 2020	Q1 2020	% change
Revenue ($ thousands)			
Oil and NGL	**$27,102**	$58,117	(53)
Natural gas	**6,193**	7,755	(20)
Total	**$33,295**	$65,872	(49)
Average realized price:			
Light oil ($/bbl)	**24.92**	46.42	(46)
Heavy oil ($/bbl)	**15.47**	49.76	(69)
Natural gas liquids ($/bbl)	**12.73**	19.44	(35)
Combined average oil and NGL ($/boe)	**23.40**	43.41	(46)
Natural gas ($/mcf)	**1.37**	1.61	(15)
Revenue ($/boe)	**17.42**	30.76	(43)

Benchmark pricing:			
West Texas Intermediate (US$/bbl)	**27.85**	46.08	(40)
Edmonton Par (Cdn$/bbl)	**29.74**	51.34	(42)
Hardisty Heavy (Cdn$/bbl)	**28.14**	34.08	(17)
NYMEX monthly settlement (US$/mmbtu)	**1.72**	1.95	(12)
AECO daily index (Cdn$/mcf)	**1.99**	2.03	(2)
AECO monthly index (Cdn$/mcf)	**1.90**	2.13	(11)

Revenue from oil, natural gas and NGL sales in Q2/20 was 43% lower per boe than in Q1/20 primarily due to lower commodity prices realized in Q2/20.

The WTI benchmark price decreased by 40% to an average of US$27.85/bbl in the second quarter of 2020 compared to US$46.08/bbl in the prior quarter, while the WTI/Edmonton Par light oil differential narrowed through Q2/20, averaging US$6.23/bbl compared to US$7.56/bbl in Q1/20. The average Edmonton Par price decreased 42% to $29.74/bbl in Q2/20 compared to $51.34/bbl in Q1/20. The second quarter was characterized by extreme market volatility due to uncertainty about near term oil demand during the global COVID-19 pandemic. This instability drove WTI to unprecedented lows during April 2020 and contributed to the exceptionally wide May 2020 Edmonton light sweet differentials, which were set during the first half of April. Despite improved stability across the quarter, the pricing improvements were not sufficient to offset the extreme lows in the earlier part of the quarter. Tamarack's realized light oil wellhead price for the three months ended June 30, 2020 decreased 46% to $24.92/bbl from $46.42/bbl in the previous quarter. This realized price reflects approximately the same difference from index as the prior quarter at $4.82/bbl ($4.92/bbl, Q1/20). The difference between index and realized pricing in the quarter was comprised of: quality, tariff, weighted average differential and loss allowance deductions (~$3.25/bbl); marketing losses due to spot purchase contracts below index due to conservative planning as well as contract buyouts on shut-in volumes (~$0.25/bbl); and a disproportionate share of volumes produced during the first two months of the quarter under lower pricing (28% of volumes in June versus 38% and 34% in April and May, respectively).

Realized NGL prices decreased 35% to $12.73/bbl in Q2/20 from $19.44/bbl in Q1/20. The decrease is due largely to the decreased WTI price in the quarter, which is the basis for condensate and butane pricing, partially offset by improved NGL contract pricing for the 2020-2021 contract year that began on April 1, 2020. Similar to other commodities, NGL supply has overwhelmed demand in the Alberta market and prices have been impacted by a lack of pipeline egress from Canada. While Tamarack realized contract improvements for the April 1, 2020-2021 contract year, NGL and oil market depression is likely to propagate poor realized pricing through summer 2020 and beyond.

Tamarack's realized natural gas price decreased 15% to $1.37/mcf in Q2/20 from $1.61/mcf in Q1/20. The AECO daily benchmark price decreased 2% to $1.99/mcf in Q2/20 from $2.03/mcf in Q1/20 while the NYMEX monthly settlement price decreased 12% to US$1.72/mmbtu in Q2/20 from US$1.95/mmbtu in Q1/20. The decrease in the Company's Q2/20 realized price and the benchmark prices compared to the previous quarter was chiefly due to seasonally lower natural gas demand across the shoulder season between winter heating and summer cooling requirements. The decrease in Tamarack's realized price deviates from the decreases seen in the two indices due to the Company's diversification strategy that balances its pricing exposure over multiple markets. While this diversification helps manage individual market volatility, it can prevent Tamarack from fully capitalizing on short-term regional market gains and may produce lower realized values when index values are close. 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's exposure to various gas markets and pricing hubs is reflected below:

Natural Gas Market	Percentage Exposure (as at June 30, 2020)
AECO Fixed Price	33.9
Waddington	22.0
Malin	17.7
Dawn	8.8
Chicago	8.8
Michigan City Gate	8.8
	100%

Despite some improvement and stabilization in AECO prices following recently approved regulatory changes, Tamarack anticipates that volatility in pricing will persist over the long term. 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. Through the second quarter of 2020, more than 60% of Tamarack's total natural gas production was priced at alternate markets to AECO, including Malin, Chicago, Michigan City Gate, Dawn and Waddington. Pricing in these markets is contracted as daily index pricing less transportation tolls or as fixed basis fees.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
	2020	2019	% change	**2020**	2019	% change
Revenue ($ thousands)						
Oil and NGL	**$27,102**	$90,434	(70)	**$85,219**	$172,666	(51)
Natural gas	**6,193**	8,307	(25)	**13,948**	21,122	(34)
Total	**$33,295**	$98,741	(66)	**$99,167**	$193,788	(49)
Average realized price:						
Light oil ($/bbl)	**24.92**	70.17	(64)	**36.46**	67.88	(46)
Heavy oil ($/bbl)	**15.47**	65.14	(76)	**33.81**	53.43	(37)
Natural gas liquids ($/bbl)	**12.73**	21.81	(42)	**16.30**	31.68	(49)
Combined average oil and NGL ($/boe)	**23.40**	65.46	(64)	**34.13**	63.80	(47)
Natural gas ($/mcf)	**1.37**	1.71	(20)	**1.50**	2.24	(33)
Revenue ($/boe)	**17.42**	45.04	(61)	**24.47**	45.32	(46)
Benchmark pricing:						
West Texas Intermediate (US$/bbl)	**27.85**	59.81	(53)	**36.97**	57.34	(36)
Edmonton Par (Cdn$/bbl)	**29.74**	72.63	(59)	**40.54**	70.05	(42)
Hardisty Heavy (Cdn$/bbl)	**28.14**	63.29	(56)	**34.28**	61.22	(44)
NYMEX monthly settlement (US$/mmbtu)	**1.72**	2.69	(36)	**1.84**	2.92	(37)
AECO daily index (Cdn$/mcf)	**1.99**	1.03	93	**2.01**	1.81	11
AECO monthly index (Cdn$/mcf)	**1.90**	1.16	64	**2.01**	1.55	30

Revenue per boe from oil, natural gas and NGL sales for Q2/20 and the first six months of 2020 decreased by 61% and 46%, respectively, compared to the same periods in 2019, primarily due to lower commodity prices realized in 2020 as a result of COVID-19 pandemic.

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 June 30, 2020, the Company held derivative commodity, foreign exchange and interest rate contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	1,000 bbls/day	July 1, 2020 – September 30, 2020	WTI fixed price	US $37.25
Crude oil	1,000 bbls/day	October 1, 2020 – December 31, 2020	WTI fixed price	US $40.03
Crude oil	1,000 bbls/day	January 1, 2021 – March 31, 2021	WTI fixed price	US $40.28
Crude oil	3,000 bbls/day	July 1, 2020 – December 31, 2020	WTI fixed price*	US $54.57
Crude oil	500 bbls/day	January 1, 2021 – June 30, 2021	WTI fixed price*	US $40.00
Crude oil	1,700 bbls/day	July 1, 2020 – September 30, 2020	WTI Put	US $58.00
Crude oil	7,000 bbls/day	July 1, 2020 – December 31, 2020	Edm par diff	US ($7.54)
Crude oil	1,000 bbls/day	January 1, 2021 – December 31, 2021	Edm par diff	US ($6.50)
Foreign exchange	3,000,000 US$/mth	July 1, 2020 – December 31, 2020	Exchange rate	Cdn $1.3863
Foreign exchange	1,500,000 US$/mth	January 1, 2021 – June 30, 2021	Exchange rate	Cdn $1.4041
Interest rate	25,000,000 US$/mth	July 1, 2020 – April 24, 2023	Fixed rate	1.90%
Interest rate	25,000,000 US$/mth	July 1, 2020 – June 14, 2023	Fixed rate	1.75%
Interest rate	20,000,000 US$/mth	July 1, 2020 – March 13, 2024	Fixed rate	1.06%
Interest rate	10,000,000 US$/mth	July 1, 2020 – March 26, 2024	Fixed rate	1.02%

* Extendable for an additional six months (January 1, 2021 – June 30, 2021 and July 1, 2021 – December 31, 2021) at the counter-party's discretion.

At June 30, 2020, the commodity, foreign exchange and interest rate contracts were fair valued with a net asset value of $8.9 million (December 31, 2019 - $4.1 million net liability) recorded on the balance sheet and an unrealized gain of $12.9 million recorded in earnings for the six months ended June 30, 2020 (June 30, 2019 - $20.6 million unrealized loss). 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.

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 June 30, 2020, the Company held the following physical commodity contracts:

Subject contract	Quantity	Remaining term	Hedge type	Strike price
Natural gas	20,825 GJ/day	April 1, 2020 – October 31, 2020	AECO fixed price	Cdn $1.25
Natural gas	10,000 GJ/day	November 1, 2020 – March 31, 2021	Malin fixed price	US $2.99
Natural gas	10,000 GJ/day	November 1, 2020 – March 31, 2021	Michigan fixed price	US $2.85
Natural gas	10,000 GJ/day	November 1, 2020 – March 31, 2021	Chicago fixed price	US $3.01
Natural gas	10,000 GJ/day	November 1, 2020 – March 31, 2021	Dawn fixed price	US $3.01
Natural gas	2,500 GJ/day	April 1, 2021 – October 31, 2021	AECO fixed price	Cdn $2.20

Since June 30, 2020, the Company has entered into the following financial contracts:

Subject contract	Quantity	Term	Hedge type	Strike price
Crude oil	1,000 bbls/day	January 1, 2021 – June 30, 2021	WTI collar*	US $40.00 Put /$50.25 Call
Crude oil	1,000 bbls/day	January 1, 2021 – June 30, 2021	Edm par diff	US $5.75

* Call portion extendable for an additional six months (July 1, 2021 – December 31, 2021) at the counter-party's discretion.

Since June 30, 2020, the Company has not entered into any additional physical commodity contracts.

Royalties

Quarter-over-Quarter

	Q2 2020	Q1 2020	% change
Royalty expenses ($ thousands)	**$4,055**	$8,082	(50)
$/boe	**2.12**	3.77	(44)
percent of sales	**12**	12	–

Royalties as a percentage of revenue were similar in Q2/20 compared to Q1/20. On an absolute basis, royalty expense was lower in Q2/20 due to the decrease in commodity prices.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
	2020	2019	% change	**2020**	2019	% change
Royalty expenses ($ thousands)	**$4,055**	$9,211	(56)	**$12,137**	$19,328	(37)
$/boe	**2.12**	4.20	(50)	**3.00**	4.52	(34)
percent of sales	**12**	9	33	**12**	10	20

Royalties as a percentage of revenue for the three and six months ended June 30, 2020 were higher than the same periods 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. The Company expects royalty rates as a percentage of revenue to decline to the 10% to 11% range for the remainder of 2020 based on current forecast commodity price levels.

Net Production and Transportation Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q2 2020**	Q1 2020	% change
Production and transportation expenses	**$18,959**	$21,779	(13)
Less: processing income (expense)	**(168)**	411	(141)
Total net production and transportation expenses	**$19,127**	$21,368	(10)
Total ($/boe)	**$10.01**	$9.98	–

Gross and net production and transportation expenses for Q2/20 were lower than Q1/20 as the Company undertook a series of cost cutting initiatives during the quarter to deal with the impact of falling commodity prices. Production and operating expenses on a per boe basis remained consistent quarter-over-quarter.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
($ thousands, except per boe)	**2020**	2019	% change	**2020**	2019	% change
Production and transportation expenses	**$18,959**	$21,959	(14)	**$40,738**	$43,784	(7)
Less: processing income (expense)	**(168)**	(215)	(22)	**243**	356	(32)
Total net production and transportation expenses	**$19,127**	$22,174	(14)	**$40,495**	$43,428	(7)
Total ($/boe)	**$10.01**	$10.12	(1)	**$9.99**	$10.16	(2)

For the three and six months ended June 30, 2020, gross and net production and transportation expenses were lower compared to the same periods in 2019. This resulted from an increase in production volumes in the Veteran area, where production expenses are generally lower than the corporate average coupled with the cost cutting initiatives undertaken during the quarter given the fall in commodity prices. Production and operating expenses on a per boe basis were slightly lower.

Operating Netback

Quarter-over-Quarter

($/boe)	**Q2 2020**	Q1 2020	% change
Average realized sales	**$17.42**	$30.76	(43)
Royalty expenses	**(2.12)**	(3.77)	(44)
Net production and transportation expenses	**(10.01)**	(9.98)	–
Operating field netback	**5.29**	17.01	(69)
Realized commodity hedging gain	**8.46**	5.10	66
Operating netback	**$13.75**	$22.11	(38)

The Company's operating netback (see "Non-IFRS Measures") decreased 38% in Q2/20 compared to Q1/20. This was primarily the result of lower commodity prices realized in Q2/20 due to the COVID-19 pandemic, partially offset by a higher realized commodity hedging gain in Q2/20.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
($/boe)	**2020**	2019	% change	**2020**	2019	% change
Average realized sales	**$17.42**	$45.04	(61)	**$24.47**	$45.32	(46)
Royalty expenses	**(2.12)**	(4.20)	(50)	**(3.00)**	(4.52)	(34)
Net production and transportation expenses	**(10.01)**	(10.12)	(1)	**(9.99)**	(10.16)	(2)
Operating field netback	**5.29**	30.72	(83)	**11.48**	30.64	(63)
Realized commodity hedging gain (loss)	**8.46**	(1.58)	(635)	**6.68**	(1.03)	(749)
Operating netback	**$13.75**	$29.14	(53)	**$18.16**	$29.61	(39)

For the three and six months ended June 30, 2020, operating netback was lower than the same periods in 2019 primarily due to lower commodity prices realized in 2020 caused by the COVID-19 pandemic, partially offset by a realized commodity hedging gain in both Q2/20 and the six months ended June 30, 2020.

General and Administrative (“G&A”) Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q2 2020**	Q1 2020	% change
Gross costs	**$3,601**	$4,311	(16)
Capitalized costs and recoveries	**(772)**	(1,193)	(35)
General and administrative costs	**$2,829**	$3,118	(9)
Total ($/boe)	**$1.48**	$1.46	1

Gross and net G&A expenses for Q2/20 were lower than Q1/20 as the Company undertook cost cutting initiatives to deal with the impact of falling commodity prices. G&A expenses on a per boe basis remained consistent quarter-over-quarter.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
($ thousands, except per boe)	**2020**	2019	% change	**2020**	2019	% change
Gross costs	**$3,601**	$4,065	(11)	**$7,912**	$7,925	–
Capitalized costs and recoveries	**(772)**	(947)	(18)	**(1,965)**	(1,847)	6
General and administrative costs	**$2,829**	$3,118	(9)	**$5,947**	$6,078	(2)
Total ($/boe)	**$1.48**	$1.42	4	**$1.47**	$1.42	4

Gross and net G&A costs decreased for Q2/20 compared to the same period in 2019, due to cost cutting initiatives to deal with the impact of falling commodity prices that occurred in Q2/20. Gross and net G&A costs for the six months ended June 30, 2020 were similar to the same period in 2019. On a per boe basis, net G&A costs for the three and six months ended June 30, 2020 were similar to the same periods in 2019.

Stock-Based Compensation Expense

Quarter-over-Quarter

($ thousands, except per boe)	**Q2 2020**	Q1 2020	% change
Gross costs	**$1,793**	$1,279	40
Capitalized costs	**(197)**	(329)	(40)
Expensed stock-based compensation	**$1,596**	$950	68
Total ($/boe)	**$0.84**	$0.44	91

Stock-based compensation expense related to stock options (“Options”), restricted share units (“RSUs”) and performance share units (“PSUs”) was higher in Q2/20 compared to Q1/20 due to a full quarter of stock-based compensation associated with Options, RSUs and PSUs that were issued late in Q1/20 as part of the Company’s annual compensation program.

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

Year-over-Year

($ thousands, except per boe)	Three months ended June 30, 2020	2019	% change	Six months ended June 30, 2020	2019	% change
Gross costs	**$1,793**	$3,075	(42)	**$3,072**	$4,863	(37)
Capitalized costs	**(197)**	(676)	(71)	**(526)**	(1,144)	(54)
Expensed stock-based compensation	**$1,596**	$2,399	(33)	**$2,546**	$3,719	(32)
Total ($/boe)	**$0.84**	$1.09	(23)	**$0.63**	$0.87	(28)

Stock-based compensation expense related to Options, RSUs and PSUs for the three and six months ended June 30, 2020 was lower compared to the same periods in 2019 due to grants being issued at a lower share price.

During the three months ended June 30, 2020, the Company issued 0.1 million RSUs.

Interest Expense

Quarter-over-Quarter

($ thousands, except per boe)	Q2 2020	Q1 2020	% change
Interest on bank debt	**$1,732**	$1,950	(11)
Fees associated with credit facility renewal	**531**	–	–
Interest on lease liabilities	**214**	224	(4)
Total interest expense	**$2,477**	$2,174	14
Total ($/boe)	**$1.30**	$1.01	29
Average drawings on bank debt	**$215,271**	$194,173	11

Interest expense was higher in Q2/20 compared to Q1/20 due to the costs associated with the credit facility renewal, partially offset by a decrease in interest rates.

Year-over-Year

($ thousands, except per boe)	Three months ended June 30, 2020	2019	% change	Six months ended June 30, 2020	2019	% change
Interest on bank debt	**$1,732**	$2,038	(15)	**$3,682**	$3,745	(2)
Fees associated with credit facility renewal	**531**	580	(8)	**531**	636	(17)
Interest on lease liabilities	**214**	253	(15)	**438**	764	(43)
Total interest expense	**$2,477**	$2,871	(14)	**$4,651**	$5,145	(10)
Total ($/boe)	**$1.30**	$1.31	(1)	**$1.15**	$1.20	(4)
Average drawings on bank debt	**$215,271**	$196,278	10	**$204,721**	$185,512	10

Total interest expense for the three and six months ended June 30, 2020 was slightly lower than the same periods in 2019 due to the lower interest on lease liabilities.

Depletion, Depreciation, Amortization and Accretion ("DDA&A")

The Company depletes its property, plant and equipment ("PP&E") based on its proved plus probable reserves. Right-of-use ("ROU") assets are depreciated on a straight-line basis over the shorter of the estimated useful life of the underlying asset or the lease term. If the lease transfers ownership of the underlying asset to the Company at the end of the lease term, or the Company is reasonably certain it will exercise its purchase option, Tamarack depletes its ROU assets based on its proved plus probable reserves. The carrying value of undeveloped land in exploration and evaluation ("E&E") assets is also amortized over its term to expiry, which is charged to DDA&A expense.

Quarter-over-Quarter

($ thousands, except per boe)	**Q2 2020**	Q1 2020	% change
Depletion and depreciation	**$27,181**	$39,391	(31)
Amortization of undeveloped leases	**157**	126	25
Accretion	**640**	640	–
Total	**$27,978**	$40,157	(30)
Depletion and depreciation ($/boe)	**$14.23**	$18.40	(23)
Amortization ($/boe)	**0.08**	0.06	33
Accretion ($/boe)	**0.33**	0.30	10
Total ($/boe)	**$14.64**	$18.76	(22)

DDA&A expense per boe and on an absolute basis decreased in Q2/20 compared to Q1/20 due to an impairment taken at the end of Q1/20. A significant decrease in forecasted oil prices caused by COVID-19 led to the Company recording an impairment charge of $381.0 million in Q1/20.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
($ thousands, except per boe)	**2020**	2019	% change	**2020**	2019	% change
Depletion and depreciation	**$27,181**	$41,533	(35)	**$66,572**	$80,657	(17)
Amortization of undeveloped leases	**157**	239	(34)	**283**	467	(39)
Accretion	**640**	1,026	(38)	**1,280**	2,171	(41)
Total	**$27,978**	$42,798	(35)	**$68,135**	$83,295	(18)
Depletion and depreciation ($/boe)	**$14.23**	$18.95	(25)	**$16.43**	$18.86	(13)
Amortization ($/boe)	**0.08**	0.11	(27)	**0.07**	0.11	(36)
Accretion ($/boe)	**0.33**	0.47	(30)	**0.32**	0.51	(37)
Total ($/boe)	**$14.64**	$19.53	(25)	**$16.82**	$19.48	(14)

For the three and six months ended June 30, 2020, DDA&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, 2019 independent reserves evaluation which resulted in an increase in Tamarack's overall reserve base following the successful 2019 drilling program, better-than-expected well performance, additional reserves being added as a result of the Veteran waterflood project in conjunction with an impairment taken in both Q4/19 and Q1/20. On an absolute basis, DDA&A expense was lower for the three and six months ended June 30, 2020 due to both lower production and reduced DDA&A expense per boe.

Income Taxes

The Company did not incur any cash tax expense for the three and six months ended June 30, 2020 and does not expect to pay any cash tax until 2023 or later based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three and six months ended June 30, 2020, a deferred income tax recovery of $10.7 million and $88.3 million, respectively, was recorded compared to a deferred income tax recovery of $2.5 million and $3.8 million for the same periods in 2019.

Adjusted Funds Flow and Net Income (Loss)

Quarter-over-Quarter

($ thousands, except per share)	**Q2 2020**	Q1 2020	% change
Cash flow from operating activities	**$28,107**	$46,359	(39)
Abandonment expenditures	**217**	1,785	(88)
Changes in non-cash working capital	**(7,352)**	(6,099)	21
Adjusted funds flow	**$20,972**	$42,045	(50)
Per share - basic	**$0.09**	$0.19	(53)
Per share - diluted	**$0.09**	$0.19	(53)
Net loss	**$(36,067)**	$(251,321)	(86)
Per share - basic	**$(0.16)**	$(1.13)	(86)
Per share - diluted	**$(0.16)**	$(1.13)	(86)

The adjusted funds flow (see "Non-IFRS Measures") and cash flow from operating activities generated during Q2/20 was lower than in Q1/20 primarily due to a 49% decrease in revenue.

The Company recorded a net loss of $36.1 million ($0.16 per share basic and diluted) during the three months ended June 30, 2020, compared to a net loss of $251.3 million ($1.13 per share basic and diluted) during the previous quarter. The lower net loss was primarily due to a $381.0 million impairment expense taken in Q1/20, partially offset by a 49% decrease in revenue and an unrealized hedging loss.

Year-over-Year

	Three months ended June 30,			Six months ended June 30,		
($ thousands, except per share)	**2020**	2019	% change	**2020**	2019	% change
Cash flow from operating activities	**$28,107**	$60,320	(53)	**$74,466**	$108,409	(31)
Abandonment expenditures	**217**	518	(58)	**2,002**	789	154
Changes in non-cash working capital	**(7,352)**	(2,932)	151	**(13,451)**	6,211	(317)
Adjusted funds flow	**$20,972**	$57,906	(64)	**$63,017**	$115,409	(45)
Per share - basic	**$0.09**	$0.26	(65)	**$0.28**	$0.51	(45)
Per share - diluted	**$0.09**	$0.25	(64)	**$0.28**	$0.50	(44)
Net income (loss)	**$(36,067)**	$16,472	(319)	**$(287,388)**	$11,646	(2,568)
Per share - basic	**$(0.16)**	$0.07	(329)	**$(1.30)**	$0.05	(2,700)
Per share - diluted	**$(0.16)**	$0.07	(329)	**$(1.30)**	$0.05	(2,700)

Adjusted funds flow and cash flow from operating activities for the three and six months ended June 30, 2020 were lower compared to the same periods in 2019. This was primarily due to a 66% and 49% decrease in revenue, respectively, in 2020.

The Company recorded a net loss of $36.1 million ($0.16 per share basic and diluted) during Q2/20 compared to net income of $16.5 million ($0.07 per share basic and diluted) in Q2/19. This was primarily due to a 66% decrease in revenue, an unrealized hedging loss in Q2/20, partially offset by a realized hedging gain in Q2/20 and lower DDA&A expense.

The Company recorded a net loss of $287.4 million ($1.30 per share basic and diluted) during the six months ended June 30, 2020, compared to net income of $11.6 million ($0.05 per share basic and diluted) for the same period in 2019. This was primarily due to a 49% decrease in revenue, a $381.0 million impairment expense taken in Q1/20, partially offset by both realized and unrealized hedging gains in 2020, higher deferred income tax recovery and lower DDA&A expense.

Capital Expenditures (Including Exploration and Evaluation Expenditures)

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

	Three months ended June 30,			Six months ended June 30,		
($ thousands)	**2020**	2019	% change	**2020**	2019	% change
Land	**$1,297**	$167	677	**$3,179**	$174	1,727
Geological and geophysical	**(7)**	3	(333)	**9**	3	200
Drilling and completion	**2,057**	15,676	(87)	**59,278**	69,862	(15)
Equipment and facilities	**2,145**	9,089	(76)	**15,868**	25,384	(37)
Capitalized G&A	**638**	805	(21)	**1,614**	1,500	8
Office equipment	**88**	162	(46)	**143**	222	(36)
Total capital expenditures	**$6,218**	$25,902	(76)	**$80,091**	$97,145	(18)

During the second quarter of 2020, the Company completed one (1.0 net) Banff oil well and incurred equipping costs related to the Company's first quarter capital program. All other spending was put on hold due to the effects of COVID-19 pandemic on commodity prices.

For the six months ended June 30, 2020 Drilling Summary		
	Gross	Net
Viking	49.0	47.8
Cardium	4.0	3.3
Penny	2.0	2.0
Water source and injectors	4.0	4.0
	59.0	57.1

As at June 30, 2020, the Company's net undeveloped land totaled 475,952 acres.

Share Capital

At June 30, 2020, Tamarack had issued and outstanding 221,221,421 Common Shares ("Common Shares"), net of 1,376,716 Common Shares which were held in treasury, 2,451,333 Options, 7,797,589 RSUs and 3,563,837 PSUs. At August 12, 2020, Tamarack has issued and outstanding 222,385,102 Common Shares, of which 213,065 are held in treasury, 2,451,333 Options, 6,663,908 RSUs and 3,563,837

PSUs. This compares to December 31, 2019, at which time Tamarack had issued and outstanding 222,793,117 Common Shares, net of 469,120 Common Shares which were held in treasury, 2,193,333 Options, 6,986,921 RSUs and 2,156,980 PSUs. No preferred shares of Tamarack are issued and outstanding.

At June 30, 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 six months ended June 30, 2020, Tamarack purchased and cancelled 664,100 outstanding Common Shares under its normal course issuer bid ("NCIB") program, for $1.3 million. This is consistent with the previously published Q1/20 results as the Company did not make any additional purchases during Q2/20. During the year ended December 31, 2019, Tamarack purchased and cancelled 4,181,000 outstanding Common Shares under its NCIB program, for $8.3 million.

Liquidity and Capital Resources

($ thousands)	**June 30, 2020**	June 30, 2019	December 31, 2019
Working capital deficiency (surplus)	**$6,599**	$8,980	$(3,426)
Bank debt	**206,467**	186,912	192,907
Net debt	**213,066**	195,892	189,481
Quarterly adjusted funds flow	**$20,972**	$57,906	$54,742
Annualized factor	**4**	4	4
Annualized adjusted funds flow	**83,888**	231,624	218,968
Net debt to annualized adjusted funds flow	**2.5x**	0.8x	0.9x

Tamarack's net debt (see "Non-IFRS Measures"), including working capital deficiency and the fair value of cross-currency swaps but excluding the fair value of financial instruments and lease liabilities, totaled $213.1 million as at June 30, 2020. This compares to its net debt of $227.2 million and $195.9 million in Q1/20 and Q2/19, respectively. Tamarack's Q2/20 net debt to annualized adjusted funds flow ratio (see "Non-IFRS Measures") was 2.5 times.

The Company's $6.2 million investment in capital expenditures during Q2/20 was funded entirely by Tamarack's adjusted funds flow (see "Non-IFRS Measures") of $21.0 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 its assets. As such, Tamarack 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 its 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 six months ended June 30, 2020, the Company spent $1.3 million to purchase and cancel 664,100 outstanding Common Shares under the NCIB program and directed $2.2 million to purchase 1,841,000 issued and outstanding Common Shares in the open market. This is consistent with the previously published Q1/20 results as the Company did not make any additional purchases during Q2/20. 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 June 30, 2020, the remaining balance of purchased Common Shares held in trust totaled 1,376,716.

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 $206.5 million was drawn as of June 30, 2020 (December 31, 2019 – $192.9 million), lasts for a 183-day period and will be subject to its next 364-day extension by November 30, 2020. If not extended by November 30, 2020, 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 June 30, 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 November 30, 2020.

There are no financial covenants governing the Facility.

Commitments

The following table summarizes the Company's commitments as at June 30, 2020:

($ thousands)	2020	2021	2022	2023	2024	2025+
Bank debt[1]	–	206,467	–	–	–	–
Office lease[2]	394	131	–	–	–	–
Take or pay commitments[3]	1,956	3,950	4,023	3,894	–	–
Gas transportation[4]	115	76	–	–	–	–
Total	2,465	210,624	4,023	3,894	–	–

(1) If not extended by November 30, 2020, the Facility will cease to revolve and all outstanding balances will become repayable November 30, 2021.

(2) Relates to the new office lease effective July 1, 2020 to February 28, 2021.

(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 lasts for 60 months.

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

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 the Company has breached its 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 condensed consolidated interim 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
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
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”, “year-end net debt to trailing annualized adjusted funds flow ratio”, “total payout ratio”, “free adjusted funds flow” and “estimated corporate sustaining capital breakeven price” which are non-IFRS financial measures. The Company uses these measures to help evaluate its 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 -** Tamarack’s method of calculating adjusted funds flow may differ from other companies, and therefore may not be comparable to measures used by other companies. 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 income (loss) per share. The calculation of the Company’s adjusted funds flows is summarized starting on page 13 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. These benchmarks do not have standardized meanings prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. 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 costs. These metrics can also be calculated on a per boe basis. Management considers operating netback and operating field netback important measures to evaluate its 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 -** Tamarack closely monitors its 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 its capital structure. Net debt does not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. The Company uses net debt (bank debt plus working capital surplus or deficiency, including the fair value of cross-currency swaps and excluding the fair value of financial instruments 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)	June 30, 2020	December 31, 2019
Accounts payable and accrued liabilities	$31,333	$37,809
Cross currency swap liability	1	2,908
Accounts receivable	(22,968)	(42,219)
Prepaid expenses and deposits	(1,767)	(1,924)
Working capital deficiency (surplus)	6,599	(3,426)
Bank debt	206,467	192,907
Net debt	$213,066	$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 does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. 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 its ability to pay off its 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 does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. 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.

(f) **Year-End Net Debt to Trailing Annual Adjusted Funds Flow Ratio**– Management uses certain industry benchmarks, such as net debt to trailing annual adjusted funds flow, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. This benchmark is calculated as estimated year-end net debt divided by estimated adjusted funds flow for the four preceding quarters at year-end. Management considers year-end net debt to trailing annual adjusted funds flow as a key measure as it provides a snapshot of the overall financial health of the Company and its ability to pay off its debt and take on new debt, if necessary, using results for the most recent four quarters at year-end.

(g) **Total Payout Ratio –** Management uses certain industry benchmarks, such as total payout ratio, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Total payout ratio is calculated as capital expenditures excluding acquisitions and dispositions, divided by adjusted funds flow. Management considers total payout ratio an important measure to evaluate its operational performance and capital allocation processes. It demonstrates the return of cash flow and allows the Company to understand how a capital program is funded under different operating scenarios, which helps assess the Company's ability to generate value.

(h) **Estimated Corporate Sustaining Capital Breakeven Price –** Management uses certain industry benchmarks, such as estimated corporate sustaining capital breakeven price, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. This benchmark is calculated as the WTI crude oil benchmark price needed to generate sufficient adjusted funds flow in order to cover the level of sustaining capital needed in order to hold current production volumes stable.

Selected Quarterly Information

Three months ended	**Jun. 30, 2020**	Mar. 31, 2020	Dec. 31, 2019	Sep. 30, 2019	Jun. 30, 2019	Mar. 31, 2019	Dec. 31, 2018 (2)	Sep. 30, 2018 (2)
Sales volumes								
Natural gas *(mcf/d)*	**49,610**	52,912	54,462	55,224	53,451	50,576	50,262	49,943
Oil and NGL *(bbls/d)*	**12,729**	14,712	15,782	14,967	15,181	14,720	16,403	16,441
Average boe/d *(6:1)*	**20,997**	23,531	24,859	24,171	24,090	23,149	24,780	24,765
Product prices								
Natural gas *($/mcf)*	**1.37**	1.61	2.26	1.54	1.71	2.82	3.70	1.63
Oil and NGL *($/bbl)*	**23.40**	43.41	59.51	59.38	65.46	62.07	37.08	73.81
Oil equivalent *($/boe)*	**17.42**	30.76	42.72	40.28	45.04	45.62	32.05	52.29
(000s, except per share amounts)								
Financial results								
Gross revenues	**33,295**	65,872	97,699	89,579	98,741	95,047	73,075	119,134
Cash provided by operating activities	**28,107**	46,359	54,623	42,199	60,320	48,089	49,137	62,644
Adjusted funds flow (1)	**20,972**	42,045	54,742	49,283	57,906	57,503	38,346	68,579
Per share – basic	**0.09**	0.19	0.25	0.22	0.26	0.25	0.17	0.30
Per share – diluted	**0.09**	0.19	0.25	0.22	0.25	0.25	0.17	0.29
Net income (loss)	**(36,067)**	(251,321)	(50,546)	(111)	16,472	(4,826)	18,952	13,004
Per share – basic	**(0.16)**	(1.13)	(0.23)	(0.00)	0.07	(0.02)	0.08	0.06
Per share – diluted	**(0.16)**	(1.13)	(0.23)	(0.00)	0.07	(0.02)	0.08	0.06
Capital expenditures	**6,218**	73,873	22,954	58,867	25,902	71,243	25,798	78,149
Net acquisitions (dispositions)	**–**	–	250	3,847	4,771	1,074	(4,823)	–
Total assets	**935,892**	984,045	1,247,119	1,369,918	1,336,323	1,349,508	1,264,053	1,291,058
Net debt(1)	**213,066**	227,151	189,481	213,140	195,892	219,348	179,880	192,184
Bank debt	**206,467**	209,423	192,907	198,971	186,912	189,427	161,495	168,970
Decommissioning obligations	**198,485**	186,816	184,846	222,684	218,950	210,198	193,003	192,409

(1) Refer to definition of adjusted funds flow and 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. Refer to the Changes in Accounting Policies section in the 2019 annual MD&A.

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 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.

- The Company recorded an impairment charge in Q1 2020 in the amount of $381.0 million on its cash-generating units ("CGU's") due to falling oil, gas and NGL prices. The impairment was recorded in the following CGU's: 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 2019 in the amount of $68.0 million on its Cardium oil CGU due to falling gas and NGL prices as that CGU has associated natural gas produced with the oil and includes Mannville gas wells and a Pekisko gas unit. The Company recorded an impairment charge in Q4 2018 in the amount of $58.0 million on its Cardium oil CGU due to falling gas prices. In the same period, the Company also recorded an impairment reversal of $53.0 million on its Viking oil CGU resulting in a net impairment expense of $5.0 million in Q4 2018.

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 plus probable reserves.

(b) **Exploration and evaluation ("E&E") assets –** The costs of drilling exploratory wells are initially capitalized as E&E assets pending the evaluation of commercial reserves. Commercial reserves are defined as the existence of proved and/or probable reserves which are determined to be technically feasible and commercially viable to extract. Reserves may be considered commercially producible if management has the intention of developing and producing them based on factors such as project economics, quantities of reserves, expected production techniques, estimated production costs and capital expenditures.

E&E expenditures relating to activities to explore and evaluate oil and natural gas properties are initially capitalized and include costs associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses, and costs associated with retiring the assets. E&E assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, aggregated at the operating segment level.

(c) **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 reserves. Changes in estimated proved and probable 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 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 flows. 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.

The Company assesses PP&E for impairment 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 exists, the Company performs an impairment test related to the specific CGU. The determination of the recoverable amount of a CGU requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and production costs. Changes in any of these assumptions, such as a downward revision in reserves, a decrease in commodity prices or an increase in costs could impact the fair value.

(d) **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.

(e) **Leases** - Judgments are made by management in the application of IFRS 16 *Leases* related to the incremental borrowing rate and lease term. The incremental borrowing rates are based on judgments including economic environment, term, currency, and the underlying risk inherent to the asset. The carrying balance of the right-of-use assets, lease obligations, and the resulting interest and depletion and depreciation expense, may differ due to changes in the market conditions and lease term. Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions.

(f) **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.

Future Accounting Pronouncements

The Company did not identify any issued but not yet effective IFRSs that are expected to significantly impact the Company's financial statements.

Changes in Accounting Standards

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.

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 its annual filings, interim filings or other reports filed or submitted by it 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.

As a result of the COVID-19 pandemic, the Company moved all its corporate office staff to work from home. This change has required certain processes and controls that were previously done or documented manually to be completed and retained in electronic form. Despite the changes required by the current environment, there have been no significant changes in the Company's internal controls during the period ended June 30, 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 its ICFR were effective as at June 30, 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 forecast. 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, 2019, 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 recent global outbreak of COVID-19. The recent COVID-19 pandemic, 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 crude oil, natural gas and NGL, and also increases the risk that storage for crude 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 extent to which it may impact 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, 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. To the extent that the COVID-19 pandemic 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, 2019.

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

Recent market events and conditions, including global excess crude 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 crude oil prices and decreased global demand due to the COVID-19 pandemic have caused significant weakness and volatility in commodity and petroleum product prices 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 crude oil and other petroleum products has deteriorated significantly and is expected to remain under pressure and be volatile. The overall result of these recent events and conditions could lead to a prolonged period of depressed prices for crude 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 have also caused a significant decrease 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. 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:

- 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 and the oil and gas industry in general;
- expectations relating to future realized commodity prices, volatile commodity prices and oil price differentials and the effects thereof;
- Tamarack's hedging position for the second half of 2020;
- Tamarack's commitment to maintaining financial flexibility;
- Tamarack being well positioned from a liquidity standpoint;
- Tamarack's commitment to ESG principles;
- Tamarack's updated pro-forma 2020 guidance, including with respect to the capital budget, production, oil and NGL weighting, free adjusted funds flow, net debt to trailing annual adjusted funds flow ratio, 2021 estimated corporate decline rate and 2021 estimate corporate sustaining capital breakeven price;
- forecasted crude oil prices, changes thereto and the impact thereof;

- uncertainty regarding the duration and extent of oil demand destruction resulting from the COVID-19 pandemic;
- Tamarack's process to evaluate shut-in economics for its production, the continued evaluation thereof and plans for production shut-ins and adjusting production rates;
- 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 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;
- future RSU 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 and operating costs;
- estimated reserves of oil and natural gas;
- 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 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", "Future Accounting Pronouncements", "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 "Responding to Volatile Oil Prices and the Novel Coronavirus (COVID-19)", "Q2 2020 Financial and Operating Highlights", "Updated Guidance", "Production", "Petroleum and Natural Gas Sales", "Royalties", "Net Production and Transportation Expenses", "Operating Netback", "General and Administrative ("G&A") Expenses", "Stock-Based Compensation Expense", "Interest Expense", "Depletion, Depreciation, Amortization and Accretion ("DDA&A")", "Income Taxes", "Adjusted Funds Flow and Net Income (Loss)", "Capital Expenditures (Including Exploration and Evaluation Expenditures)", "Share Capital", "Liquidity and Capital Resources", "Bank Debt", "Commitments", "Contingency" and "Selected Quarterly 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 crude 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 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, 2019, 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, free adjusted funds flow, net debt to trailing annual adjusted funds flow ratio, corporate decline rates, corporate sustaining capital breakeven price, royalty rates and components thereof, 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.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Balance Sheets
(unaudited)(thousands)

	June 30, 2020	December 31, 2019
Assets		
Current assets:		
Accounts receivable (note 5)	$22,968	$42,219
Prepaid expenses and deposits	1,767	1,924
Fair value of financial instruments (note 4)	11,184	114
	35,919	44,257
Fair value of financial instruments (note 4)	210	275
Property, plant and equipment (note 6)	847,937	1,200,950
Exploration and evaluation assets (note 7)	1,773	1,637
Deferred tax asset	50,053	–
	$935,892	$1,247,119
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$31,333	$37,809
Lease liabilities (note 9)	2,292	2,209
Cross-currency swap (note 13)	1	2,908
Fair value of financial instruments (note 4)	1,059	4,475
	34,685	47,401
Fair value of financial instruments (note 4)	1,473	–
Bank debt (note 13)	206,467	192,907
Lease liabilities (note 9)	8,794	9,961
Decommissioning obligations (note 8)	198,485	184,846
Deferred tax liability	–	38,229
	449,904	473,344
Shareholders' equity:		
Share capital (note 11)	830,248	832,799
Treasury shares (note 11)	(1,611)	(969)
Contributed surplus	50,605	47,811
Deficit	(393,254)	(105,866)
	485,988	773,775
Subsequent event (note 4 and 17)		
Commitments (note 15)		
Contingency (note 16)		
	$935,892	$1,247,119

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Income (Loss) and Comprehensive Income (Loss)
For the three and six months ended June 30, 2020 and 2019
(unaudited)(thousands, except per share amounts)

	Three months ended June 30,		Six months ended June 30,	
	2020	2019	2020	2019
Revenue:				
Oil and natural gas (note 5)	$33,295	$98,741	$99,167	$193,788
Processing income (expense) (note 5)	(168)	(215)	243	356
Royalties	(4,055)	(9,211)	(12,137)	(19,328)
Realized gain (loss) on financial instruments (note 4)	16,165	(3,461)	27,080	(4,400)
Unrealized gain (loss) on financial instruments (note 4)	(38,244)	1,251	12,948	(20,558)
	6,993	87,105	127,301	149,858
Expenses:				
Production	18,959	21,959	40,738	43,784
General and administration	2,829	3,118	5,947	6,078
Stock-based compensation (note 14)	1,596	2,399	2,546	3,719
Finance	3,022	3,897	5,885	7,316
Depletion, depreciation and amortization (note 6 and 7)	27,338	41,772	66,855	81,124
Impairment of property, plant and equipment (note 6)	–	–	381,000	–
	53,744	73,145	502,971	142,021
Income (loss) before taxes	(46,751)	13,960	(375,670)	7,837
Deferred income tax recovery	10,684	2,512	88,282	3,809
Net income (loss) and comprehensive income (loss)	$(36,067)	$16,472	$(287,388)	$11,646
Net income (loss) per share (note 12):				
Basic	$(0.16)	$ 0.07	$(1.30)	$ 0.05
Diluted	$(0.16)	$ 0.07	$(1.30)	$ 0.05

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Changes in Shareholders' Equity
(unaudited)(thousands)

	Number of common shares, net of treasury shares	Share capital	Treasury shares	Contributed surplus	Deficit	Total Shareholders' equity
Balance at January 1, 2019	226,072	$848,249	$(3,377)	$34,554	$(66,855)	$812,571
Issue of common shares	15	41	–	–	–	41
Settlement of RSUs	163	595	–	(782)	–	(187)
Purchase of common shares for cancellation	(927)	(3,563)	–	1,339	–	(2,224)
Purchase of common shares for RSU exercise	(499)	–	(1,251)	–	–	(1,251)
RSU exercise	665	–	1,868	(1,868)	–	–
Transfer on exercise of Options	–	26	–	(26)	–	–
Stock-based compensation	–	–	–	4,863	–	4,863
Net income	–	–	–	–	11,646	11,646
Balance at June 30, 2019	225,489	$845,348	$(2,760)	$38,080	$(55,209)	$825,459

Balance at January 1, 2020	222,793	$832,799	$(969)	$47,811	$(105,866)	$773,775
Purchase of common shares for cancellation	(664)	(2,551)	–	1,262	–	(1,289)
Purchase of common shares for RSU exercise	(1,841)	–	(2,182)	–	–	(2,182)
RSU exercise	933	–	1,540	(1,540)	–	–
Stock-based compensation	–	–	–	3,072	–	3,072
Net loss	–	–	–	–	(287,388)	(287,388)
Balance at June 30, 2020	221,221	$830,248	$(1,611)	$50,605	$(393,254)	$485,988

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Cash Flows
For the three and six months ended June 30, 2020 and 2019
(unaudited)(thousands)

	Three months ended June 30,		Six months ended June 30,	
	2020	2019	2020	2019
Cash provided by (used in):				
Operating:				
Net income (loss)	$(36,067)	$16,472	$(287,388)	$11,646
Depletion, depreciation and amortization (note 6 and 7)	27,338	41,772	66,855	81,124
Stock-based compensation (note 14)	1,596	2,399	2,546	3,719
Accretion expense on decommissioning obligations (note 8)	640	1,026	1,280	2,171
Unrealized (gain) loss on financial instruments (note 4)	38,244	(1,251)	(12,948)	20,558
Unrealized (gain) loss on foreign exchange	(1,537)	–	2,861	–
Unrealized (gain) loss on cross-currency swap (note 13)	1,442	–	(2,907)	–
Impairment of property, plant and equipment (note 6)	–	–	381,000	–
Deferred income tax recovery	(10,684)	(2,512)	(88,282)	(3,809)
Abandonment expenditures (note 8)	(217)	(518)	(2,002)	(789)
Changes in non-cash working capital (note 10)	7,352	2,932	13,451	(6,211)
Cash provided by operating activities	28,107	60,320	74,466	108,409
Financing:				
Change in bank debt (note 13)	(1,419)	(2,515)	10,699	25,417
Proceeds from issuance of shares	–	41	–	41
Purchase of common shares for cancellation	–	(1,541)	(1,289)	(2,224)
Purchase of common shares for RSU exercises	–	(1,251)	(2,182)	(1,438)
Purchase of leased asset	–	–	–	(22,328)
Repayment of lease liabilities (note 9)	(547)	(508)	(1,084)	(1,693)
Cash provided by (used in) financing activities	(1,966)	(5,774)	6,144	(2,225)
Investing:				
Property, plant and equipment additions (note 6)	(5,760)	(25,870)	(79,617)	(97,106)
Exploration and evaluation additions (note 7)	(458)	(32)	(474)	(39)
Acquisitions	–	(4,771)	–	(5,845)
Changes in non-cash working capital (note 10)	(19,923)	(23,873)	(519)	(3,194)
Cash used in investing activities	(26,141)	(54,546)	(80,610)	(106,184)
Change in cash and cash equivalents	–	–	–	–
Cash and cash equivalents, beginning of period	–	–	–	–
Cash and cash equivalents, end of period	$ –	$ –	$ –	$ –

See accompanying notes to the condensed consolidated interim financial statements.

1. Reporting entity:

Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") is a corporation existing under the laws of Alberta. The Company is engaged in the exploration for, development and production of, oil and natural gas. The condensed consolidated interim financial statements of Tamarack consist of the Company and its subsidiaries. The Company has the following wholly owned subsidiaries, which are incorporated in Canada: Tamarack Acquisition Corp. and Tamarack Valley Ridge Holdings Ltd. The Company also has a subsidiary incorporated in the United States: Tamarack Ridge Resources Inc. No assets are held within Tamarack Ridge Resources Inc. or Tamarack Valley Ridge Holdings Ltd. Tamarack is a publicly traded company, incorporated and domiciled in Canada. The address of its registered office is Suite 4300, 888 – 3rd Street S.W., Calgary, Alberta, T2P 5C5. The address of its head office is currently Suite 600, 425 – 1st Street S.W., Calgary, Alberta, T2P 3L8.

2. Basis of preparation:

Statement of compliance:

The condensed consolidated interim financial statements have been prepared in accordance with International Accounting Standard 34, "Interim Financial Reporting" of International Financial Reporting Standards ("IFRS").

These condensed consolidated interim financial statements have been prepared following the same accounting policies and methods of computation as the annual consolidated financial statements of the Company for the year ended December 31, 2019 except as detailed in note 3. The disclosures provided below are incremental to those included with the annual consolidated financial statements and certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. These condensed consolidated interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company's annual filings for the year ended December 31, 2019.

The condensed consolidated interim financial statements were authorized for issue by the Board of Directors on August 12, 2020.

Estimates and judgments:

The preparation of the condensed consolidated interim financial statements in conformity with IFRS requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities as at the date of the condensed consolidated interim financial statements and the reported amounts of revenues and expenses during the period. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future periods could require a material change in the interim financial statements. Accordingly, actual results may differ from the estimated amounts as future confirming events occur. The significant estimates and judgments made by management in the preparation of these condensed consolidated interim financial statements were consistent with those applied to the annual consolidated financial statements as at and for the year ended December 31, 2019.

Subsequent to December 31, 2019, global oil prices declined considerably caused by reduced demand driven by the novel coronavirus ("COVID-19") health pandemic and over supply concerns stemming from failed negotiations between OPEC+ countries on production curtailments. While the OPEC+ countries have now reached an agreement on production cuts, the macro environment remains weak and considerable uncertainty exists regarding the duration and extent of oil demand destruction from the COVID-19 pandemic. There have also been significant stock market declines, significant volatility in foreign exchange markets, and restrictions on the conduct of business in many jurisdictions. The current challenging economic climate may have significant adverse impacts on the Company, including, but not limited to:

- material declines in revenue and cash flows due to reduced commodity pricing,
- declines in future revenue could result in increased impairment charges to long-term assets,
- increased risk of non-performance by the Company's customers which could materially increase collection risk of accounts receivable and customer defaults on contracts, and
- prolonged demand destruction could negatively impact the Company's ability to maintain liquidity.

The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and the financial effect to the Company is not known at this time. Estimates and judgements made by management in the preparation of these condensed consolidated interim financial statements are subject to a higher degree of measurement uncertainty during this volatile period. As an understanding of the longer-term impacts of COVID-19 on commodity, credit and equity markets develops, there is amplified potential for changes in these estimates and judgments over the remainder of 2020.

3. New accounting standard:

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 January 1, 2020 and apply prospectively. The adoption of this standard had no impact to the Company.

4. Risk management contracts:

It is the Company's policy to economically hedge some oil and natural gas sales, foreign exchange rates and interest rates using various financial derivative forward sales contracts and physical sales contracts. The Company does not apply hedge accounting for these contracts. The Company's production is usually sold using "spot" or near-term contracts, with prices fixed at the time of transfer of custody or based on a monthly average market price. The Company, however, may give consideration in certain circumstances to the appropriateness of entering into long-term, fixed price marketing contracts. The Company does not enter into commodity contracts other than to meet its expected sales requirements. 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.

All financial derivative contracts are classified as fair value through profit and loss and are recorded on the balance sheet at fair value. The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and level 2 published forward price curves as at the balance sheet date, using the remaining contracted amounts and a risk-free interest rate (based on published government rates). The fair value of options and swaps are based on option models that use level 2 inputs, being published information with respect to volatility, prices and interest rates. The derivatives are valued at fair value through profit or loss and therefore the carrying amount equals fair value.

At June 30, 2020, the Company held derivative commodity, foreign exchange and interest rate contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value (Cdn $000s)
Crude oil	1,000 bbls/day	July 1, 2020 – September 30, 2020	WTI fixed price	US $37.25	($903)
Crude oil	1,000 bbls/day	October 1, 2020 – December 31, 2020	WTI fixed price	US $40.03	$33
Crude oil	1,000 bbls/day	January 1, 2021 – March 31, 2021	WTI fixed price	US $40.28	$39
Crude oil	3,000 bbls/day	July 1, 2020 – December 31, 2020	WTI fixed price*	US $54.57	$10,789
Crude oil	500 bbls/day	January 1, 2021 – June 30, 2021	WTI fixed price*	US $40.00	($811)
Crude oil	1,700 bbls/day	July 1, 2020 – September 30, 2020	WTI Put	US $58.00	$3,967
Crude oil	7,000 bbls/day	July 1, 2020 – December 31, 2020	Edm par diff	US ($7.54)	($3,342)
Crude oil	1,000 bbls/day	January 1, 2021 – December 31, 2021	Edm par diff	US ($6.50)	$421
Foreign exchange	3,000,000 US$/mth	July 1, 2020 – December 31, 2020	Exchange rate	Cdn $1.3863	$524
Foreign exchange	1,500,000 US$/mth	January 1, 2021 – June 30, 2021	Exchange rate	Cdn $1.4041	$340
Interest rate	25,000,000 US$/mth	July 1, 2020 – April 24, 2023	Fixed rate	1.90%	($917)
Interest rate	25,000,000 US$/mth	July 1, 2020 – June 14, 2023	Fixed rate	1.75%	($850)
Interest rate	20,000,000 US$/mth	July 1, 2020 – March 13, 2024	Fixed rate	1.06%	($297)
Interest rate	10,000,000 US$/mth	July 1, 2020 – March 26, 2024	Fixed rate	1.02%	($131)
					$8,862

* Extendable for an additional six months (January 1, 2021 – June 30, 2021 and July 1, 2021 – December 31, 2021) at the counter-party's discretion.

At June 30, 2020, Tamarack's commodity, foreign exchange and interest rate contracts were fair valued with a net asset of $8,862 (December 31, 2019 - $4,086 net liability) recorded on the balance sheet. The Company had an unrealized gain of $12,948 recorded in earnings for the six months ended June 30, 2020 (six months ended June 30, 2019 - $20,558 unrealized loss).

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 June 30, 2020, the Company held the following physical commodity contracts:

Subject contract	Quantity	Remaining term	Hedge type	Strike price
Natural gas	20,825 GJ/day	April 1, 2020 – October 31, 2020	AECO fixed price	Cdn $1.25
Natural gas	10,000 GJ/day	November 1, 2020 – March 31, 2021	Malin fixed price	US $2.99
Natural gas	10,000 GJ/day	November 1, 2020 – March 31, 2021	Michigan fixed price	US $2.85
Natural gas	10,000 GJ/day	November 1, 2020 – March 31, 2021	Chicago fixed price	US $3.01
Natural gas	10,000 GJ/day	November 1, 2020 – March 31, 2021	Dawn fixed price	US $3.01
Natural gas	2,500 GJ/day	April 1, 2021 – October 31, 2021	AECO fixed price	Cdn $2.20

Risk management contracts assets and liabilities are offset, and the net amount presented in the balance sheet, when the Company has a legal right to offset the amounts and intends to settle them on a net basis or to realize the asset and settle the liability simultaneously.

The following table sets out gross amounts relating to risk management contracts assets and liabilities that have been presented on a net basis on the balance sheet.

Gross Amounts ($ thousands)	**June 30, 2020**	December 31, 2019
Risk management contracts		
Current asset	**$11,184**	$114
Long-term asset	**210**	275
Current liability	**(1,059)**	(4,475)
Long-term liability	**(1,473)**	–
Balance, end of the period	**$8,862**	$(4,086)

Since June 30, 2020, the Company has entered into the following derivative contracts:

Subject contract	Quantity	Term	Hedge type	Strike price
Crude oil	1,000 bbls/day	January 1, 2021 – June 30, 2021	WTI collar*	US $40.00 Put /$50.25 Call
Crude oil	1,000 bbls/day	January 1, 2021 – June 30, 2021	Edm par diff	US $5.75

* Call portion extendable for an additional six months (July 1, 2021 – December 31, 2021) at the counter-party's discretion.

Since June 30, 2020, the Company has not entered into any additional physical contracts.

5. Revenue:

The Company sells its production pursuant to fixed-price or variable-price contracts. The transaction price for variable-price contracts is based on a benchmark commodity price, adjusted for quality, location or other factors whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver fixed or variable volumes of light oil, heavy oil, natural gas or NGL to the contract counterparty.

Revenue is recognized when the Company gives up control of the unit of production at the delivery point agreed to under the terms of the contract. The amount of revenue recognized is based on the agreed transaction price and the volumes delivered. Any variability in the transaction price relates specifically to Tamarack's efforts to transfer production and therefore the resulting revenue is allocated to the production volumes delivered in the period to which the variability relates. The Company does not have any factors considered to be constraining in the recognition of revenue with variable pricing factors. The Company's contracts with customers generally have a term of one year or less, except in the case of certain natural gas contracts, whereby delivery takes place throughout the contract period. Revenues are normally collected on the business day nearest the 25th day of the month following sale.

The Company's revenues were primarily generated in its core areas: the Cardium oil play in the Wilson Creek/Alder Flats areas of central Alberta; the Viking oil play in central and southern Alberta and west central Saskatchewan; and the Barons Sand oil play in the Penny area of southern Alberta. The Company's customers are oil and natural gas marketers and joint operations partners in the oil and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing volumes to numerous oil and natural gas marketers under customary industry sale and payment terms. As at June 30, 2020, four customers accounted for $12.8 million of the accounts receivable (December 31, 2019, four customers accounted for $28.7 million).

The following table presents the Company's total revenues disaggregated by revenue source:

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2020**	2019	**2020**	2019
Light oil	**$25,183**	$84,523	**$79,542**	$159,301
Heavy oil	**220**	3,088	**1,033**	4,853
Natural gas	**6,193**	8,307	**13,948**	21,122
Natural gas liquids	**1,699**	2,823	**4,644**	8,512
Oil and natural gas revenue	**$33,295**	$98,741	**$99,167**	$193,788
Processing income (expense)	**(168)**	(215)	**243**	356
Total revenue	**$33,127**	$98,526	**$99,410**	$194,144

Refer to note 4 for a listing of physical delivery contracts as at June 30, 2020.

Included in accounts receivable at June 30, 2020 was $15.9 million (December 31, 2019 - $34.7 million) of accrued production revenue related to deliveries for the month then ended. There were no significant adjustments for prior period accrued production revenue reflected in the current period. As at June 30, 2020, the Company did not have any contracts for the sale of its future production beyond one year in term, except certain natural gas contracts that expire in 2022.

6. Property, plant and equipment:

($ thousands)	Oil and natural gas interests	Other assets	Total
Cost:			
Balance at January 1, 2019	$1,858,155	$1,585	$1,859,740
Right-of-use assets	37,236	–	37,236
Property acquisitions	10,598	–	10,598
Cash additions	178,678	410	179,088
Decommissioning costs	(8,719)	–	(8,719)
Stock-based compensation	2,384	–	2,384
Transfer from exploration and evaluation assets (note 7)	30	–	30
Disposals	(2,035)	–	(2,035)
Balance at December 31, 2019	2,076,327	1,995	2,078,322
Cash additions	79,474	143	79,617
Decommissioning costs	14,361	–	14,361
Stock-based compensation	526	–	526
Transfer from exploration and evaluation assets (note 7)	55	–	55
Balance at June 30, 2020	$2,170,743	$2,138	$2,172,881
Accumulated depletion, depreciation and impairment losses:			
Balance at January 1, 2019	$643,187	$920	$644,107
Depletion and depreciation	166,049	263	166,312
Disposals	(1,047)	–	(1,047)
Impairment	68,000	–	68,000
Balance at December 31, 2019	876,189	1,183	877,372
Depletion and depreciation	66,441	131	66,572
Impairment	381,000	–	381,000
Balance at June 30, 2020	$1,323,630	$1,314	$1,324,944

	Oil and natural gas interests	Other assets	Total
Carrying amounts:			
At December 31, 2019	$1,200,138	$812	$1,200,950
At June 30, 2020	$847,113	$824	$847,937

The calculation of depletion at June 30, 2020 includes estimated future development costs of $642,307 (December 31, 2019 – $700,604) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $73,930 (December 31, 2019 – $70,791).

Certain facilities and surface leases are included in property, plant and equipment as right-of-use assets:

($ thousands)	Processing facilities	Surface leases	Total
As at January 1, 2020	$9,402	$1,736	$11,138
Depletion and depreciation	(768)	(79)	(847)
Impairment	(3,123)	(308)	(3,431)
Balance at June 30, 2020	$5,511	$1,349	$6,860

At March 31, 2020 impairment of $381.0 million was recorded as a result of a decrease in current and forecast oil, natural gas and NGL prices. The impairment recognized relates to all of the Company's cash-generating units ("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 recoverable amount of these CGU's as at March 31, 2020, net of decommissioning obligations, was estimated to be $447.9 million for the Viking oil CGU, $137.9 million for the Cardium oil CGU, $81.4 million for the Penny oil CGU and ($11.1) million for the minor gas CGU based on the net present value of before tax cash flows from proved plus probable reserves estimated by the Company's third party reserve evaluator internally updated by the Company to March 31, 2020 for production and forward prices as at that date at discount rates specific to the underlying composition of reserve categories of 10% to 20% (level 3 inputs). The recoverable amounts of all of the CGUs was determined using the fair value less costs of disposal methodology based on what Tamarack estimates it could receive for these assets if it disposed of them in the current environment taking into account lower oil, natural gas and NGL prices. The impairment of $381,000 was allocated to property, plant and equipment in the amount of $377,569 and $3,431 was allocated to the right-of-use asset.

7. Exploration and evaluation assets:

($ thousands)	Total
Cost:	
Balance at January 1, 2019	$26,006
Additions	(122)
Transfer to property, plant and equipment	(30)
Balance at December 31, 2019	25,854
Additions	474
Transfer to property, plant and equipment (note 6)	(55)
Balance at June 30, 2020	$26,273
Accumulated amortization and impairment:	
Balance at January 1, 2019	$23,218
Amortization	999
Balance at December 31, 2019	24,217
Amortization	283
Balance at June 30, 2020	$24,500

	Total
Carrying amounts:	
At December 31, 2019	$1,637
At June 30, 2020	$1,773

E&E assets consist of the Company's exploration projects which are pending the determination of proven or probable reserves. Additions represent the Company's share of costs incurred on E&E assets during the period.

8. Decommissioning obligations:

The decommissioning obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted and uninflated amount of cash flows required to settle its decommissioning obligations to be approximately $197.3 million at June 30, 2020 (December 31, 2019 – $195.6 million), which is expected to be incurred between 2021 and 2042. A risk-free rate of 1.0% (December 31, 2019 – 1.8%) and an inflation rate of 1.0% (December 31, 2019 – 1.4%) is used to calculate the present value of the decommissioning obligations at June 30, 2020 as presented in the table below:

($ thousands)	**Six months ended June 30, 2020**	Year ended December 31, 2019
Balance, beginning of the period	**$184,846**	$193,003
Liabilities incurred	**3,115**	12,031
Change in estimates	**11,246**	(20,750)
Expenditures	**(2,002)**	(3,154)
Liabilities disposed	**–**	(359)
Accretion	**1,280**	4,075
Balance, end of the period	**$198,485**	$184,846

The change in estimate for the six months ended June 30, 2020 resulted from decommissioning obligations being revalued using a risk-free rate of 1.0% and an inflation rate of 1.0% as opposed to a risk free-rate of 1.8% and an inflation rate of 1.4% used at December 31, 2019.

9. Lease liabilities:

The Company has lease liabilities for contracts related to financing facilities and surface leases. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. Discount rates used during the three and six months ended June 30, 2020 were between 6.8% and 8.8%, depending on the duration of the lease. The following table summarizes lease liabilities at June 30, 2020:

($ thousands)	**June 30, 2020**
Balance, beginning of the period	**$12,170**
Interest expense	**438**
Lease payments	**(1,522)**
Balance, end of the period	**$11,086**
Current portion	**$2,292**
Long term portion	**$8,794**

Undiscounted cash outflows relating to the lease liabilities are:

($ thousands)	As at June 30, 2020
Less than 1 year	$3,043
Years 2 and 3	6,066
Years 4 and 5	3,845
Thereafter	3,079
Total	$16,033

10. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2020**	2019	**2020**	2019
Source/(use) of cash:				
Accounts receivable	**$9,219**	$11,858	**$19,251**	$(8,029)
Prepaid expenses and deposits	**(161)**	(1,067)	**157**	(1,481)
Accounts payable and accrued liabilities	**(21,629)**	(31,732)	**(6,476)**	105
	$(12,571)	$(20,941)	**$12,932**	$(9,405)
Related to operating activities	**$7,352**	$2,932	**$13,451**	$(6,211)
Related to investing activities	**$(19,923)**	$(23,873)	**$(519)**	$(3,194)

The following are included in cash provided by operating activities:

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2020**	2019	**2020**	2019
Interest paid in cash on bank debt	**$1,732**	$2,038	**$3,682**	$3,745
Bank renewal fees	**531**	580	**531**	636
Interest paid on lease liabilities	**214**	253	**438**	764

11. Shareholders' equity:

a) Share capital:

At June 30, 2020 the Company was authorized to issue an unlimited number of common shares ("Common Shares") and preferred shares without nominal or par value.

b) Normal course issuer bid:

On April 4, 2019, the Company announced that the Toronto Stock Exchange had accepted the Company's intention to commence a normal course issuer bid ("NCIB"). Pursuant to the NCIB, the Company is permitted to purchase up to 8.6 million Common Shares between April 8, 2019 and April 7, 2020. The Company has decided not to renew the NCIB at this time due to the COVID-19 pandemic. During the six months ended June 30, 2020, the Company purchased and cancelled 0.7 million Common Shares at an average price of $1.94 per Common Share, for a total repurchase cost of $1.3 million.

c) Treasury shares:

During the six months ended June 30, 2020, the Company spent $2.2 million to purchase 1.8 million Common Shares to be used to settle restricted share units ("RSUs") on the date of exercise. As at June 30, 2020, 1,376,716 (December 31, 2019 – 469,120) Common Shares remain classified as treasury shares to be used for future settlements.

12. Net income (loss) per share:

The following table summarizes the net income (loss) and weighted average shares used in calculating net income (loss) per share:

	Three months ended June 30,		Six months ended June 30,	
($ thousands, except per share amounts)	**2020**	2019	**2020**	2019
Net income (loss)	**$(36,067)**	$16,472	**$(287,388)**	$11,646
Weighted average shares - basic	**221,142**	225,989	**221,612**	226,166
Weighted average shares - diluted	**221,142**	231,152	**221,612**	231,287
Net income (loss) per share-basic	**$(0.16)**	$ 0.07	**$(1.30)**	$ 0.05
Net income (loss) per share-diluted	**$(0.16)**	$ 0.07	**$(1.30)**	$ 0.05

Per share amounts have been calculated using the weighted average number of Common Shares outstanding. For the three and six months ended June 30, 2020, 14.5 million Common Shares issuable upon the exercise and/or settlement of stock options ("Options"), RSUs, performance share units ("PSUs") and TAC Preferred Shares (as defined below) were excluded from the diluted weighted average number of Common Shares outstanding as they were anti-dilutive due to the net loss. For both the three and six months ended June 30, 2019, 8.6 million Common Shares issuable upon the exercise and/or settlement of Options, RSUs, PSUs and TAC Preferred Shares were included in the diluted weighted average number of Common Shares outstanding.

13. Bank debt:

The Company currently has available a revolving credit facility in the amount of $255 million and a $20 million operating facility (collectively, the "Facility") with a syndicate of lenders. The Facility, totaling $275 million, will be subject to its next 364-day extension by November 30, 2020. If not extended on November 30, 2020, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that date.

The total interest rate on the Facility is determined through a pricing grid that categorizes based on both a net debt-to-cash-flow ratio and the total amount drawn down 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 June 30, 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 November 30, 2020.

At June 30, 2020, the Company had utilized the Facility in the amount of $206.5 million (December 31, 2019 - $192.9 million). The interest rate applicable to the drawn amounts as of this date was 4.27%. As at June 30, 2020, the Company had letter of guarantees outstanding in the amount of $0.2 million against the Facility (December 31, 2019 - $0.2 million). There are no financial covenants governing the Facility.

The Company manages its credit facility using a combination of prime rate loans, bankers' acceptance notes and US dollar denominated London Inter-bank Offered Rate ("LIBOR") loans. During the three months ended June 30, 2020, concurrent with the drawdown of US dollar LIBOR loans, the Company entered into cross-currency swaps (“CCS”) to fix the foreign exchange on US dollar LIBOR loan amounts for purposes of interest and principal repayments. At June 30, 2020, the Company had drawn US$60.0 million, fixed at notional amounts of $81.5 million through various CCS (December 31, 2019 – the Company had drawn US$141.0 million, fixed at notional amounts of $185.9 million through various CCS).

14. Share-based payments:

(a) Preferred share plan:

At June 30, 2020, there are 740,307 (December 31, 2019 – 1,021,974) preferred shares of Tamarack Acquisition Corp. (the “TAC Preferred Shares”) issued and outstanding. At June 30, 2020, the TAC Preferred Shares were fully vested and exchangeable into 711,834 (December 31, 2019 – 982,667) Common Shares at an exchange price of $3.12 per Common Share.

Under the terms of the Company’s preferred share plan, a cashless settlement alternative is available, whereby holders of TAC Preferred Shares can either (i) elect to receive Common Shares by delivering cash to the Company in the amount of the TAC Preferred Shares, or (ii) elect to receive a number of Common Shares equivalent to the market value of the TAC Preferred Shares in excess of the TAC Preferred Shares at the exchange price of $3.12 per Common Share. For the three and six months ended June 30, 2020 no TAC Preferred Shares were exchanged and 281,667 TAC Preferred Shares were forfeited.

(b) Options:

Pursuant to the Company’s stock option plan (the “Stock Option Plan”) and the Company’s performance and restricted share unit plan (the “PRSU Plan”), the Company may grant up to an aggregate of 15.5 million Options, RSUs and PSUs to officers, employees, directors and consultants of the Company or its subsidiaries, as applicable. As at June 30, 2020, there was an aggregate of 13.8 million Options, RSUs and PSUs issued and outstanding.

Options issued under the Stock Option Plan do not have an exercise price of less than the market price of the Common Shares at the time of grant, do not exceed a five-year term and vest one-third on each of the first, second and third anniversaries from the date of grant. There were 0.6 million Options granted during the six months ended June 30, 2020 (December 31, 2019 – 0.4 million).

The fair value of each Option granted during the six months ended June 30, 2020 was estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value and weighted average assumptions used to fair value the options are as follows:

	2020
Risk free rate (%)	**0.71**
Expected volatility (%)	**51**
Expected life (years)	**5**
Forfeiture rate (%)	**–**
Dividend ($ per share)	**–**
Fair value at grant date ($ per option)	**0.49**

The number and weighted average exercise prices of the Options are as follows:

	Number of Options (thousands)	Weighted average exercise price
Outstanding, January 1, 2019	2,945	$3.95
Granted	390	2.57
Exercised	(15)	2.75
Expired	(1,127)	5.32
Outstanding, December 31, 2019	2,193	$3.01
Granted	559	1.13
Forfeited/expired	(301)	3.16
Outstanding, June 30, 2020	**2,451**	**$2.56**

The range of exercise prices of the Options outstanding and exercisable at June 30, 2020 is as follows:

	Options outstanding			Options exercisable	
Range of exercise price	Number outstanding (thousands)	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable (thousands)	Weighted average exercise price
$ 0.64 – 2.50	559	$1.13	4.7	–	–
$ 2.51 – 2.81	1,071	$2.66	1.8	801	$2.69
$ 2.82 – 3.44	821	$3.40	1.5	821	$3.40
$ 0.64 – 3.44	**2,451**	**$2.56**	**2.3**	**1,622**	**$3.05**

(c) RSUs:

The PRSU Plan allows the Board of Directors to grant RSUs to officers, employees, consultants and non-employee directors of the Company or its subsidiaries. Each RSU entitles the holder to an award value to be paid as to one-third on each of the first, second and third anniversaries of the date of grant. There were 2.0 million RSUs granted during the six months ended June 30, 2020 (December 31, 2019 – 2.5 million).

For the purpose of calculating stock-based compensation, the fair value of each RSU is determined at the grant date using the closing price of the Common Shares. On the date of exercise, the Company has the option of settling the RSU value in cash or in Common Shares of the Company.

The following table summarizes information about the RSUs:

	Number of RSUs (thousands)
Outstanding, January 1, 2019	7,407
Granted	2,533
Exercised	(2,596)
Forfeited	(357)
Outstanding, December 31, 2019	6,987
Granted	1,956
Exercised	(933)
Forfeited	(212)
Outstanding, June 30, 2020	**7,798**
Exercisable, June 30, 2020	**3,625**

(d) PSUs:

The PRSU Plan allows the Board of Directors to grant PSU awards to officers, employees and consultants of the Company or its subsidiaries. Each PSU entitles the holder to an award value on the third anniversary of the date of grant multiplied by a payout multiplier ranging from 0 to 2.0 times. The payout multiplier for performance-based awards will be determined by the Board of Directors based on an assessment of the Company's achievement of predefined corporate performance measures in respect of the applicable period. There were 1.7 million PSUs granted during the six months ended June 30, 2020 (December 31, 2019 – 1.2 million).

For the purpose of calculating stock-based compensation, the fair value of each award is determined at the grant date using the closing price of the Common Shares. On the date of exercise, the Company has the option of settling the PSU value in cash or in Common Shares of the Company.

The following table summarizes information about the PSU awards:

	Number of PSU awards (thousands)
Outstanding, January 1, 2019	983
Awarded	1,211
Forfeited	(37)
Outstanding, December 31, 2019	2,157
Awarded	1,657
Forfeited	(250)
Outstanding, June 30, 2020	**3,564**
Earned, June 30, 2020	**683**
Exercisable, June 30, 2020	**–**

15. Commitments:

The following table summarizes the Company's commitments as at June 30, 2020:

($ thousands)	2020	2021	2022	2023	2024	2025+
Office lease(1)	394	131	–	–	–	–
Take or pay commitments(2)	1,956	3,950	4,023	3,894	–	–
Gas transportation(3)	115	76	–	–	–	–
Total	2,465	4,157	4,023	3,894	–	–

(1) Relates to the new office lease effective July 1, 2020 to February 28, 2021.

(2) 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 lasts for 60 months.

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

16. 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 the Company has breached its 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 these condensed consolidated interim financial statements.

17. Subsequent event:

Subsequent to quarter end, on July 9, 2020 the Company entered into and closed a purchase agreement to acquire assets located in West Central, Alberta (the "Assets"). The Assets include approximately 2,500 boe/d (52% oil and natural gas liquids) of production and approximately 105,000 net acres of land, acquired for total cash consideration of $4.25 million (before customary adjustments).

CORPORATE INFORMATION

Directors

Floyd Price - Chairman[(3)(4)]

Jeff Boyce[(1)(4)]

John Leach[(1)(2)]

Ian Currie[(2)(4)]

Rob Spitzer[(3)(2)]

Marnie Smith[(1)(3)]

Brian Schmidt

(1) Member of the Audit Committee of the Board of Directors
(2) Member of the Reserves Committee of the Board of Directors
(3) Member of the Compensation & Governance Committee of the Board of Directors
(4) Member of the Health, Safety & Environmental Committee of the Board of Directors

Management Team

Brian Schmidt
President & Chief Executive Officer

Steve Buytels
VP Finance & Chief Financial Officer

Dave Christensen
VP Engineering

Ken Cruikshank
VP Land

Martin Malek
VP Corporate Planning & Business Development

Kevin Screen
VP Production & Operations

Scott Reimond
VP Exploration

Sony Gill
Corporate Secretary

Lead Bank Syndicate

National Bank of Canada

Legal Counsel

Stikeman Elliott LLP

Auditor

KPMG LLP

Stock Exchange

Toronto Stock Exchange
Stock symbol: TVE

Contact Information

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