Second Quarter 2019 Interim Report — Date: July 24, 2019

The following discussion of the financial condition, changes in financial condition and results of operations of Western Energy Services Corp. (the "Company" or "Western") should be read in conjunction with the audited consolidated financial statements and accompanying notes of the Company for the years ended December 31, 2018 and 2017, the Company's management discussion and analysis ("MD&A") for the year ended December 31, 2018, as well as the condensed consolidated financial statements and notes as at and for the three and six months ended June 30, 2019 and 2018. This MD&A is dated July 24, 2019. All amounts are denominated in Canadian dollars (CDN$) unless otherwise identified.

Financial Highlights	**Three months ended June 30**			**Six months ended June 30**		
(stated in thousands, except share and per share amounts)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Revenue	37,728	33,141	14%	103,503	114,398	(10%)
Operating Revenue[1]	34,692	30,976	12%	96,465	103,941	(7%)
Gross Margin[1]	6,792	5,562	22%	22,324	25,833	(14%)
Gross Margin as a percentage of Operating Revenue	20%	18%	11%	23%	25%	(8%)
Adjusted EBITDA[1]	2,438	897	172%	13,686	16,009	(15%)
Adjusted EBITDA as a percentage of Operating Revenue	7%	3%	133%	14%	15%	(7%)
Cash flow from operating activities	17,501	26,313	(33%)	23,389	30,177	(22%)
Capital expenditures	1,691	5,426	(69%)	3,883	10,082	(61%)
Net loss	(10,128)	(15,475)	(35%)	(17,206)	(21,422)	(20%)
-basic net loss per share	(0.11)	(0.17)	(35%)	(0.19)	(0.23)	(17%)
-diluted net loss per share	(0.11)	(0.17)	(35%)	(0.19)	(0.23)	(17%)
Weighted average number of shares						
-basic	92,307,042	92,178,383	-	92,306,939	92,177,719	-
-diluted	92,307,042	92,178,383	-	92,306,939	92,177,719	-
Outstanding common shares as at period end	92,307,042	92,179,281	-	92,307,042	92,179,281	-
Operating Highlights[1]						
Contract Drilling						
Canadian Operations						
Average active rig count	7.0	9.2	(24%)	12.8	19.1	(33%)
Operating Revenue per Billable Day	20,167	19,453	4%	19,664	19,113	3%
Operating Revenue per Operating Day	22,022	21,363	3%	21,988	21,218	4%
Drilling rig utilization - Billable Days	14%	18%	(22%)	26%	38%	(32%)
Drilling rig utilization - Operating Days	13%	17%	(24%)	23%	34%	(32%)
CAODC industry average utilization - Operating Days[2]	14%	17%	(18%)	22%	29%	(24%)
United States Operations						
Average active rig count	4.3	2.1	105%	4.9	2.7	81%
Operating Revenue per Billable Day (US$)	20,286 [3]	22,815	(11%)	19,968 [3]	21,040	(5%)
Operating Revenue per Operating Day (US$)	23,576 [3]	25,865	(9%)	23,402 [3]	23,356	-
Drilling rig utilization - Billable Days	54%	34%	59%	64%	45%	42%
Drilling rig utilization - Operating Days	46%	30%	53%	55%	40%	38%
Production Services						
Canadian Operations						
Average active rig count	13.0	10.5	24%	18.0	15.5	16%
Service rig Operating Revenue per Service Hour	655	723	(9%)	665	710	(6%)
Service rig utilization	20%	16%	25%	28%	23%	22%

(1) See "Non-IFRS Measures" on page 19 of this MD&A.

(2) Source: The Canadian Association of Oilwell Drilling Contractors ("CAODC"). The CAODC industry average is based on Operating Days divided by total available days.

(3) Excludes shortfall commitment revenue from take or pay contracts of US$1.3 million for the three and six months ended June 30, 2019.

Financial Position at (stated in thousands)	June 30, 2019	December 31, 2018	June 30, 2018
Working capital	4,981	15,739	7,717
Property and equipment	591,935	615,395	634,812
Total assets	626,890	667,295	670,584
Long term debt	223,363	222,258	210,944

Overall Performance and Results of Operations

Western is an oilfield service company focused on three core business lines: contract drilling, well servicing and oilfield rental equipment services. Western provides contract drilling services through its division, Horizon Drilling ("Horizon") in Canada, and its wholly owned subsidiary, Stoneham Drilling Corporation ("Stoneham") in the United States ("US"). Western provides well servicing and oilfield rental equipment services in Canada through its wholly owned subsidiary Western Production Services Corp. ("Western Production Services"). Western Production Services' division, Eagle Well Servicing ("Eagle") provides well servicing operations, while its division, Aero Rental Services ("Aero") provides oilfield rental equipment services. Stoneham's division, Western Oilfield Services, provides well servicing operations in the United States. Financial and operating results for Horizon and Stoneham are included in Western's contract drilling segment, while financial and operating results for Eagle, Aero, and Western Oilfield Services are included in Western's production services segment. Non-International Financial Reporting Standards ("Non-IFRS") measures, such as Operating Revenue, Gross Margin, Adjusted EBITDA and Operating Loss, are defined on page 19 of this MD&A. Abbreviations for standard industry terms are included on page 20 of this MD&A.

Western has a drilling rig fleet of 57 rigs specifically suited for drilling complex horizontal wells. Western is currently the fourth largest drilling contractor in Canada, based on the Canadian Association of Oilwell Drilling Contractors ("CAODC") registered rigs, with a fleet of 49 rigs operating through Horizon. Of the Canadian fleet, 23 are classified as Cardium class rigs, 19 as Montney class rigs and seven as Duvernay class rigs. As compared to the Cardium class rigs, the Montney class rigs have a larger hookload, while the Duvernay class rigs have the largest hookload allowing the rig to support more drill pipe downhole. Additionally, Western has eight drilling rigs operating through Stoneham in the US, including six Duvernay class rigs. Western is also the fifth largest well servicing company in Canada with a fleet of 63 rigs operating through Eagle. Additionally, Western Oilfield Services has three well servicing rigs operating in the Bakersfield area of California in the US. Western's oilfield rental equipment division, which operates through Aero, provides oilfield rental equipment for hydraulic fracturing services, well completions and production work, coil tubing and drilling services.

Crude oil and natural gas prices impact the cash flow of Western's customers, which in turn impacts the demand for Western's services. The following table summarizes average crude oil and natural gas prices, as well as average foreign exchange rates, for the three and six months ended June 30, 2019 and 2018.

	Three months ended June 30			Six months ended June 30		
	2019	2018	Change	2019	2018	Change
Average crude oil and natural gas prices(1)(2)						
Crude Oil						
West Texas Intermediate (US$/bbl)	59.84	67.88	(12%)	57.33	65.38	(12%)
Western Canadian Select (CDN$/bbl)	65.75	62.81	5%	61.20	55.78	10%
Natural Gas						
30 day Spot AECO (CDN$/mcf)	1.08	1.18	(8%)	1.82	1.59	14%
Average foreign exchange rates(2)						
US dollar to Canadian dollar	1.34	1.29	4%	1.33	1.28	4%

(1) See "Abbreviations" on page 20 of this MD&A.

(2) Source: Sproule

West Texas Intermediate ("WTI") on average declined for both the three and six months ended June 30, 2019 by 12%, compared to the same periods in the prior year. However, pricing on Canadian crude oil increased for both the three and six months ended June 30, 2019, as compared to the same periods in the prior year, due to improved price differentials as a result of the mandated crude oil production curtailments implemented by the Government of Alberta, coupled with a weaker Canadian dollar. As a result, the price for Western Canadian Select ("WCS") increased by 5% and 10% respectively, for the three and six months ended June 30, 2019. Natural gas prices in Canada were volatile and declined for the three months ended June 30, 2019, as the 30 day spot AECO price decreased by 8% over the same period in the prior year; however, for the six months ended June 30, 2019, the 30 day spot AECO price improved by 14%, compared to the same period of the prior year.

In the United States, market conditions have remained relatively stable in 2019. As reported by Baker Hughes, a GE Company, the average number of active drilling rigs in the United States decreased by 5% in the second quarter of 2019 as compared to the same period in the prior year, while for the six months ended June 30, 2019, active drilling rigs increased by approximately 2% as compared to the same period in the prior year. In Canada, market conditions have deteriorated despite improved year to date prices for Canadian crude oil and natural gas. The mandated crude oil production curtailments implemented by the Government of Alberta and continued industry concerns over market access, increased regulation, and the prevailing customer preference to return cash to shareholders, or pay down debt, rather than grow production have resulted in a decrease in industry activity in Canada. The CAODC reported that for drilling in Canada, the total number of Operating Days in the Western Canadian Sedimentary Basin ("WCSB") decreased by approximately 25% and 31% respectively, for the three and six months ended June 30, 2019, as compared to the same periods in the prior year.

Operational results for the three months ended June 30, 2019 include:

- Second quarter Operating Revenue increased by $3.7 million to $34.7 million in 2019 as compared to $31.0 million in 2018. In the contract drilling segment, Operating Revenue totalled $25.2 million in the second quarter of 2019, an increase of $3.4 million (or 16%) as compared to $21.8 million in the second quarter of 2018, and included US$1.3 million in shortfall commitment revenue. In the production services segment, Operating Revenue totalled $9.6 million for the three months ended June 30, 2019, as compared to $9.2 million for the three months ended June 30, 2018, an increase of $0.4 million (or 4%). Activity was higher for contract drilling in the United States and for well servicing in Canada; whereas lower contract drilling and oilfield rental equipment activity in Canada impacted Operating Revenue as described below:
    - Drilling rig utilization – Operating Days ("Drilling Rig Utilization") in Canada decreased to 13% in the second quarter of 2019 compared to an average of 17% in the same period of the prior year, reflecting a 400 basis points ("bps") reduction. The decrease in activity was mainly attributable to mandated crude oil production curtailments in Alberta, coupled with continued market uncertainty and as a result, customers have reduced their 2019 drilling programs. Second quarter 2019 Drilling Rig Utilization of 13% represented a discount of 100 bps to the CAODC industry average of 14%, a decrease as compared to the second quarter of 2018 when Drilling Rig Utilization of 17% was consistent with the industry average. The decrease in the Company's utilization as compared to the industry average in 2019 was a function of a smaller industry rig fleet, as older rigs continue to be decommissioned and higher specification rigs continue to move out of the WCSB. Western's market share, represented by the Company's Operating Days as a percentage of the CAODC's total Operating Days in the WCSB, remained consistent at 8% in both the second quarter of 2019 and the second quarter of 2018. Despite lower activity, pricing improved and resulted in a 4% increase in Operating Revenue per Billable Day in the second quarter of 2019, as compared to the same period in the prior year, as day rates on the Company's high specification Duvernay class and Montney class rigs have improved.
    - In the United States, improved WTI prices led to six of the Company's eight drilling rigs working during the quarter, three of which were operating on term contracts. During the fourth quarter of 2018, the Company purchased one Cardium class drilling rig for its fleet in the United States, which commenced operations in the Permian basin. Additionally, a Duvernay class rig from the Canadian fleet was deployed to the Permian Basin in the first quarter of 2019. As a result of a larger and more geographically diversified rig fleet in the second quarter of 2019, Operating Days increased by 104%, as compared to the same period in the prior year. Furthermore, Drilling Rig Utilization improved to 46% in the second quarter of 2019, compared to 30% in the same period of the prior year. While day rates on the Company's high specification Duvernay class rigs improved, Operating Revenue per Billable Day for the second quarter of 2019, excluding shortfall commitment revenue, decreased by 11% as the newly acquired Cardium class rig, which worked at a lower day rate and also has a significantly lower capital investment, decreased the average day rate in the United States; and
    - In Canada, service rig utilization was 20% in the second quarter of 2019 compared to 16% in the same period of the prior year. The increase is due to continued efforts by management to improve activity with existing customers and broaden the Company's customer base, despite customer programs being impacted by continued market uncertainty. While utilization improved, service rig Operating Revenue per Service Hour decreased during the second quarter of 2019 by 9%, as compared to the same period in the prior year, due to pricing pressure in certain operating areas. Higher utilization, offset partially by lower pricing, led to well servicing Operating Revenue in the period increasing to $7.6 million, an improvement of $0.7 million (or 10%), as compared to the same period in the prior year.

- Second quarter Adjusted EBITDA increased by $1.5 million (or 172%) to $2.4 million in 2019 as compared to $0.9 million in the second quarter of 2018. The year over year change in Adjusted EBITDA is due to US$1.3 million in shortfall commitment revenue earned in the quarter and higher utilization for contract drilling in the United States, offset partially by lower Adjusted EBITDA in all Canadian divisions, as well as $0.4 million in costs related to establishing well servicing operations for Western Oilfield Services in the United States.
- Administrative expenses, excluding depreciation and stock based compensation, decreased by $0.3 million (or 7%) to $4.4 million, as compared to $4.7 million in the second quarter of 2018, mainly due to lower rent expense as a result of the adoption of IFRS 16.
- The Company incurred a net loss of $10.1 million in the second quarter of 2019 ($0.11 per basic common share) as compared to a net loss of $15.5 million in the same period in 2018 ($0.17 per basic common share). The change can be attributed to:
  - A $1.5 million increase in Adjusted EBITDA, mainly due to US$1.3 million in shortfall commitment revenue; and
  - A $3.6 million increase in income tax recovery due to the reduction in the provincial corporate tax rate that was substantively enacted by the Government of Alberta in the second quarter of 2019;

  Offsetting the above mentioned items was:
  - A $0.2 million increase in finance costs due to higher long term debt balances outstanding in the quarter; and
  - A $0.1 million change in other items, which include gains and losses on foreign exchange and asset sales.
- Second quarter 2019 capital expenditures of $1.7 million consist primarily of maintenance capital. In total, capital spending in the second quarter of 2019 decreased by $3.7 million from the $5.4 million incurred in the second quarter of 2018.

Operational results for the six months ended June 30, 2019 include:

- Operating Revenue for the six month period ended June 30, 2019 decreased by $7.4 million to $96.5 million as compared to $103.9 million for the six month period ended June 30, 2018. In the contract drilling segment, Operating Revenue totalled $71.1 million for the six months ended June 30, 2019, including US$1.3 million of shortfall commitment revenue, and reflects a decrease of $8.0 million (or 10%) as compared to $79.1 million for the six months ended June 30, 2018. In the production services segment, Operating Revenue totalled $25.5 million for the six months ended June 30, 2019, as compared to $25.0 million in the same period of the prior year, an increase of $0.5 million (or 2%). Activity was higher for contract drilling in the United States and for well servicing in Canada; whereas lower contract drilling and oilfield rental equipment activity in Canada impacted Operating Revenue as described below:
  - Drilling Rig Utilization in Canada for the six month period ended June 30, 2019 decreased to 23%, compared to an average of 34% for the six month period ended June 30, 2018, reflecting a 1,100 bps reduction. The decrease in activity was mainly attributable to mandated crude oil production curtailments in Alberta, coupled with heightened market uncertainty and as a result, customers have reduced their 2019 drilling programs. Drilling Rig Utilization of 23% in 2019 represented a premium of 100 bps to the CAODC industry average of 22%, whereas in the first six months of 2018, Drilling Rig Utilization of 34% represented a 500 bps premium to the CAODC industry average. The decrease in the Company's utilization premium to the industry average in 2019 was a function of a smaller industry rig fleet, as older rigs continue to be decommissioned and higher specification rigs continue to move out of the WCSB. Western's market share, represented by the Company's Operating Days as a percentage of the CAODC's total Operating Days in the WCSB, was 9.2% for the first six months of 2019, as compared to 9.6% in the same period of the prior year. Despite lower activity, pricing reflects a 3% improvement in Operating Revenue per Billable Day in 2019, as compared to the same period in the prior year, as day rates have increased in all rig classes.
  - In the United States, seven of the Company's eight drilling rigs worked year to date, three of which were operating on term contracts. During the fourth quarter of 2018, the Company purchased one Cardium class drilling rig for its fleet in the United States, which commenced operations in the Permian basin. Additionally, a Duvernay class rig from the Canadian fleet was deployed to the Permian Basin in the first quarter of 2019. As a result of a larger and more geographically diversified rig fleet in the first six months of 2019, Operating Days increased by 73% in 2019, as compared to the same period in the prior year. Furthermore, Drilling Rig Utilization improved to 55% for the six months ended June 30, 2019, compared to 40% in the same period of the prior year. While day rates on the Company's high specification Duvernay class rigs improved, Operating Revenue per Billable Day for the six months ended June 30, 2019, excluding shortfall commitment revenue, decreased by 5%

as the newly acquired Cardium class rig, which worked at a lower day rate and also has a significantly lower capital investment, decreased the average day rate in the United States; and

  - In Canada, service rig utilization was 28% for the six months ended June 30, 2019 compared to 23% in the same period of the prior year. The increase is due to continued efforts by management to improve activity with existing customers and broaden the Company's customer base, despite customer programs being impacted by continued market uncertainty. While utilization improved, service rig Operating Revenue per Service Hour decreased during the six months ended June 30, 2019 by 6%, as compared to the same period in the prior year, due to pricing pressure in certain operating areas. Higher utilization, offset partially by lower pricing, led to well servicing Operating Revenue in the period increasing to $21.4 million, an improvement of $1.5 million (or 8%), as compared to the same period in the prior year.

- Adjusted EBITDA for the six months ended June 30, 2019 decreased by $2.3 million (or 15%) to $13.7 million as compared to $16.0 million for the six months ended June 30, 2018. The year over year change in Adjusted EBITDA is due to lower Adjusted EBITDA in all Canadian divisions, coupled with $0.8 million in costs related to establishing well servicing operations for Western Oilfield Services in the United States, which was offset partially by shortfall commitment revenue and increased contract drilling activity in the United States.
- Administrative expenses, excluding depreciation and stock based compensation, for the six month period ended June 30, 2019 decreased by $1.2 million (or 12%) to $8.6 million, as compared to $9.8 million in the same period of the prior year, mainly due to lower rent expense as a result of the adoption of IFRS 16, coupled with lower employee related costs.
- The Company incurred a net loss of $17.2 million for the six months ended June 30, 2019 ($0.19 per basic common share) as compared to a net loss of $21.4 million in the same period in 2018 ($0.23 per basic common share). The change can be attributed to:
  - A $4.9 million increase in income tax recovery due to the reduction in the provincial corporate tax rate that was substantively enacted by the Government of Alberta in the second quarter of 2019;
  - A $0.5 million decrease in finance costs, due to $0.6 million of non-cash accretion expense recognized in the prior year related to the early redemption of the Company's senior notes;
  - A $0.5 million decrease in stock based compensation expense;
  - A $0.4 million decrease in depreciation expense due to certain assets being fully depreciated in the period; and
  - A $0.2 million change in other items, which include gains and losses on foreign exchange and asset sales.

  Offsetting the above mentioned items was a $2.3 million decrease in Adjusted EBITDA, mainly due to lower Adjusted EBITDA in all Canadian divisions and startup costs related to establishing well servicing operations for Western Oilfield Services in the US, offset partially by shortfall commitment revenue and increased contract drilling activity in the United States.
- Year to date capital expenditures of $3.9 million included $1.2 million of expansion capital and $2.7 million of maintenance capital. In total, capital spending for the six months ended June 30, 2019 decreased by $6.2 million from the $10.1 million incurred in the same period of the prior year. The Company incurred expansion capital mainly related to drilling rig upgrades, as well as required maintenance capital, in 2019.
- On January 1, 2019, the Company adopted IFRS 16, Leases, using the modified retrospective method. The adoption of IFRS 16 resulted in an increase in long term debt of $12.8 million, an increase in property and equipment of $10.1 million, a decrease in provisions of $1.4 million, a decrease in the deferred tax liability of $0.4 million, a decrease in other assets of $0.1 million, and a net decrease in retained earnings of $1.1 million. For the three and six months ended June 30, 2019, the impact of IFRS 16 on Adjusted EBITDA was an increase of $0.8 million and $1.6 million respectively, whereas the impact on net loss was less than $0.1 million in each respective period, as increased Adjusted EBITDA was offset by higher depreciation and finance costs.

Outlook

Currently, 19 of Western's drilling rigs are operating. Five of Western's 57 drilling rigs (or 9%) are under term take or pay contracts, with two expected to expire in 2019, two expected to expire in 2020 and one expected to expire in 2021. These contracts each typically generate between 250 and 350 Billable Days per year.

Western's capital budget for 2019 remains unchanged and is expected to total $15 million with $2 million allocated for expansion capital and $13 million for maintenance capital. Western believes the 2019 capital budget provides a prudent use of cash resources and will allow it to maintain its premier drilling and well servicing rig fleets, while remaining responsive to customer requirements. Western will continue to manage its operations in a disciplined manner and make required adjustments to its capital program as customer demand changes.

Mandated crude oil production cuts in Alberta and uncertainty surrounding takeaway capacity related to the timing of construction on the Trans Mountain pipeline expansion and the Keystone XL pipeline, as well as the in service date of the Enbridge Line 3 pipeline replacement, have resulted in the announced 2019 capital budgets for Western's Canadian customers decreasing significantly year over year. As such, year over year activity levels in Canada are expected to decrease in 2019. Controlling fixed costs and maintaining balance sheet flexibility are priorities for the Company, as prices for Western's services remain below historical levels. However, Western's variable cost structure and a prudent capital budget will aid in preserving balance sheet strength.

Given the outlook for oilfield services in Canada, Western is proactively looking to deploy existing assets from Canada into more active resource plays in the United States. In the first quarter of 2019, Western transferred a Duvernay class drilling rig from Canada to the Permian Basin in the United States, increasing the United States drilling rig fleet to eight rigs. Additionally, in 2019, the Company began establishing well servicing operations in the United States and relocated three well service rigs from Canada to the Bakersfield area of California. Bakersfield is located in a mature basin where the demand for well interventions is high. Western's three well service rigs deployed in this area fit the profile of wells being serviced and feature engines that are compliant with the California Air Resources Board on-highway emissions standards.

As at June 30, 2019, Western had $5.2 million drawn on its $60.0 million credit facilities, consisting of its syndicated first lien credit facility (the "Revolving Facility") and its committed operating facility (the "Operating Facility" and together the "Credit Facilities"), which mature on December 17, 2021 and currently has $212.3 million outstanding on its Second Lien Facility, which matures on January 31, 2023.

Oilfield service activity in Canada will be affected by the development of resource plays in Alberta and northeast British Columbia which will be impacted by pipeline construction, environmental regulations, and the level of investment in Canada. Currently, the largest challenges facing the oilfield service industry are limited take away capacity, continued customer spending constraints relative to historical levels, and the challenge of staffing field crews. Western's rig fleet is well positioned to benefit from the recently approved liquefied natural gas project in British Columbia. It is also Western's view that its modern drilling and well servicing rig fleets, reputation, and disciplined cash management provide a competitive advantage which will enable the Company to manage through the current oilfield service environment.

Segmented Information

Western operates in the contract drilling segment as well as in the production services segment in both Canada and the United States. Contract drilling includes drilling rigs along with related equipment. Production services includes well servicing rigs and related equipment as well as oilfield rental equipment.

Contract Drilling

Financial Highlights	**Three months ended June 30**			**Six months ended June 30**		
(stated in thousands)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Revenue						
Operating Revenue[1]	25,184	21,791	16%	71,068	79,141	(10%)
Third party charges	2,430	1,730	40%	5,988	9,319	(36%)
Total revenue	27,614	23,521	17%	77,056	88,460	(13%)
Expenses						
Operating						
Cash operating expenses	21,334	19,431	10%	58,292	68,426	(15%)
Depreciation	12,638	13,149	(4%)	25,176	26,261	(4%)
Stock based compensation	60	132	(55%)	90	236	(62%)
Total operating expenses	34,032	32,712	4%	83,558	94,923	(12%)
Administrative						
Cash administrative expenses	2,327	2,311	1%	4,368	4,732	(8%)
Depreciation	60	57	5%	120	113	6%
Stock based compensation	(24)	37	(165%)	(9)	63	(114%)
Total administrative expenses	2,363	2,405	(2%)	4,479	4,908	(9%)
Gross Margin[1]	6,280	4,090	54%	18,764	20,034	(6%)
Gross Margin as a percentage of Operating Revenue	25%	19%	32%	26%	25%	4%
Adjusted EBITDA[1]	3,953	1,779	122%	14,396	15,302	(6%)
Adjusted EBITDA as a percentage of Operating Revenue	16%	8%	100%	20%	19%	5%
Operating Earnings (Loss)[1]	(8,745)	(11,427)	(23%)	(10,900)	(11,072)	(2%)
Capital expenditures	1,260	4,921	(74%)	3,186	8,695	(63%)

Operating Highlights

Canadian Operations						
Contract drilling rig fleet:						
Average active rig count[1]	7.0	9.2	(24%)	12.8	19.1	(33%)
End of period	49	50	(2%)	49	50	(2%)
Operating Revenue per Billable Day[1]	20,167	19,453	4%	19,664	19,113	3%
Operating Revenue per Operating Day[1]	22,022	21,363	3%	21,988	21,218	4%
Operating Days[1]	582	761	(24%)	2,075	3,112	(33%)
Number of meters drilled	197,863	244,535	(19%)	690,672	918,741	(25%)
Number of wells drilled	45	59	(25%)	172	237	(27%)
Average Operating Days per well	13.1	12.8	2%	12.1	13.2	(8%)
Drilling rig utilization - Billable Days[1]	14%	18%	(22%)	26%	38%	(32%)
Drilling rig utilization - Operating Days[1]	13%	17%	(24%)	23%	34%	(32%)
CAODC industry average utilization - Operating Days[1][2]	14%	17%	(18%)	22%	29%	(24%)

United States Operations						
Contract drilling rig fleet:						
Average active rig count[1]	4.3	2.1	105%	4.9	2.7	81%
End of period	8	6	33%	8	6	33%
Operating Revenue per Billable Day (US$)[1]	20,286 [3]	22,815	(11%)	19,968 [3]	21,040	(5%)
Operating Revenue per Operating Day (US$)[1]	23,576 [3]	25,865	(9%)	23,402 [3]	23,356	-
Operating Days[1]	338	166	104%	760	440	73%
Number of meters drilled	98,640	57,659	71%	218,587	136,478	60%
Number of wells drilled	23	11	109%	49	26	88%
Average Operating Days per well	14.7	15.1	(3%)	15.5	16.9	(8%)
Drilling rig utilization - Billable Days[1]	54%	34%	59%	64%	45%	42%
Drilling rig utilization - Operating Days[1]	46%	30%	53%	55%	40%	38%

(1) See "Non-IFRS Measures" on page 19 of this MD&A.

(2) Source: CAODC. The CAODC industry average is based on Operating Days divided by total available days.

(3) Excludes shortfall commitment revenue from take or pay contracts of US$1.3 million for the three and six months ended June 30, 2019.

For the three months ended June 30, 2019, Operating Revenue in the contract drilling segment totalled $25.2 million, a $3.4 million increase (or 16%), as compared to the same period of the prior year, as higher activity and shortfall commitment revenue in the United States, was partially offset by decreased activity in Canada. For the six months ended June 30, 2019, Operating Revenue in the contract drilling segment totalled $71.1 million, an $8.0 million decrease (or 10%), as compared to the same period in the prior year. Operating Revenue in 2019 was impacted by lower industry activity in Canada as customers reduced their drilling programs due to the mandated Government of Alberta production curtailments and market uncertainty; however, an increased and more geographically diverse rig fleet in the United States led to higher year over year activity. While pricing in Canada improved by 4% and 3% in the three and six months ended June 30, 2019 respectively, pricing in the United States decreased by 11% and 5% in the three and six months ended June 30, 2019 respectively, as compared to the same periods in the prior year, mainly due to changes in the average rig mix.

For the three months ended June 30, 2019, third party charges per Billable Day in the contract drilling segment increased to approximately $2,400, as compared to approximately $1,700 in the same period of the prior year, whereas for the six months ended June 30, 2019, third party charges per Billable Day in the contract drilling segment decreased to approximately $1,900, as compared to approximately $2,400 in the same period of the prior year. The variance for both the three and six months ended June 30, 2019 is mainly due to changes in the mix of customers who request the Company pay for the rig fuel initially, which the Company then recharges back to the customer, instead of the customer electing to purchase fuel directly from a third party provider.

For the three months ended June 30, 2019, cash operating expenses per Billable Day in the contract drilling segment, excluding third party charges, decreased by 3% to $16,805, as compared to $17,295 in the same period of the prior year, mainly due to lower salaries and related costs in the Permian Basin area, where a higher proportion of Billable Days were worked. For the six months ended June 30, 2019, cash operating expenses per Billable Day, excluding third party charges, decreased by 2% to $14,671, as compared to $14,990 in the same period of the prior year mainly due to a higher proportion of Billable Days in the Permian Basin area, which has lower salaries and related costs, partially offset by one time mobilization costs of $0.6 million incurred related to moving one Duvernay class drilling rig from the Canadian fleet to the Permian Basin in the first quarter of 2019.

Gross Margin per Billable Day, excluding shortfall commitment revenue and one time mobilization costs, remained relatively consistent year to date in 2019 with the three months ended June 30, 2019 increasing by 2% due to improved day rates in Canada, and the six months ended June 30, 2019, decreasing by 2%, mainly due to lower day rates in the United States, as compared to the same periods in the prior year.

Contract drilling Adjusted EBITDA for the three months ended June 30, 2019 increased by $2.2 million to $4.0 million, as compared to $1.8 million for the three months ended June 30, 2018, mainly due to shortfall commitment revenue and increased activity in the United States. For the six months ended June 30, 2019, contract drilling Adjusted EBITDA decreased by $0.9 million to $14.4 million, as compared to $15.3 million in the same period of the prior year, mainly due to lower activity in Canada, which was offset partially by shortfall commitment revenue and increased activity in the United States.

For the three and six months ended June 30, 2019, cash administrative expenses, which exclude depreciation and stock based compensation, totalled $2.3 million and $4.4 million respectively, and were 1% and 8% lower respectively, than the same periods of the prior year, mainly due to lower rent expense as a result of the adoption of IFRS 16.

Depreciation expense for the three and six months ended June 30, 2019 totalled $12.7 million and $25.3 million, and reflect decreases of $0.5 million and $1.1 million over the same periods of the prior year, mainly due to certain assets being fully depreciated in the period.

Capital expenditures in the contract drilling segment totalled $1.3 million and $3.2 million for the three and six months ended June 30, 2019. Capital expenditures in the second quarter of primarily relate to maintenance capital, whereas capital expenditures for the first half of 2019 include $1.0 million of expansion capital and $2.2 million of maintenance capital. Contract drilling capital expenditures in 2019 were significantly lower than the prior year and include expansion capital relating to rig upgrades, as well as required maintenance capital.

Canadian Operations

While the price for Canadian crude oil and natural gas improved during the first six months of 2019, activity in the WCSB declined as most customers reduced their drilling programs, largely due to economic factors such as the crude oil production curtailments mandated by the Government of Alberta. As a result, during the three months ended June 30, 2019, Operating Days decreased by 24% and Drilling Rig Utilization in Canada declined to 13% as compared to 17% in the same period of the prior year. Similarly, for the six months ended June 30, 2019, Operating Days decreased by 33% and Drilling Rig Utilization in Canada declined to 23% as compared to 34% in the same period in 2018.

Drilling Rig Utilization in Canada of 13% in the second quarter of 2019 reflects a 100 bps discount to the CAODC average of 14%, as compared to being consistent with the CAODC average of 17% in the second quarter of 2018. Drilling Rig Utilization in Canada of 23% for the six month period ended June 30, 2019 reflects a 100 bps premium to the CAODC average of 22%, as compared to a 500 bps premium in the same period of the prior year. The decrease in the Company's premium to the CAODC average for both the three and six months ended June 30, 2019 was due to a smaller industry rig fleet, as older rigs continue to be decommissioned and higher specification rigs continue to move out of the WCSB. Western's market share, represented by the Company's Operating Days as a percentage of the CAODC's total Operating Days in the WCSB, remained consistent at 8.1% and 9.2% for the three and six months ended June 30, 2019 respectively, as compared to 8.0% and 9.6% respectively, in the same periods of the prior year.

For the quarter ended June 30, 2019, Operating Revenue per Billable Day in Canada improved by 4% and totalled $20,167, compared to $19,453 in the same period of the prior year. For the six months ended June 30, 2019, Operating Revenue per Billable Day in Canada increased by 3% and totalled $19,664, compared to $19,113 in the six months ended June 30, 2018. The improvement in pricing for both the three and six months ended June 30, 2019 is due to day rates being held constant or increasing in all rig classes.

United States Operations

A larger drilling rig fleet and improved market conditions led to seven of the Company's eight United States drilling rigs operating during the first half of 2019. This resulted in Western's Operating Days in the United States increasing for both the three and six months ended June 30, 2019. For the second quarter of 2019, Operating Days increased by 172 days (or 104%) which resulted in Drilling Rig Utilization of 46%, as compared to 30% in the same period of the prior year. Similarly, for the six months ended June 30, 2019, Operating Days improved by 320 days (or 73%) which resulted in Drilling Rig Utilization of 55%, as compared to 40% in the six months ended June 30, 2018.

Operating Revenue per Billable Day, excluding shortfall commitment revenue, decreased in the second quarter of 2019 by 11% to US$20,286, as compared to US$22,815 in the second quarter of 2018. Similarly, for the six months ended June 30, 2019, Operating Revenue per Billable Day decreased by 5% to US$19,968, as compared to US$21,040 in the same period of the prior year. While day rates on the Company's high specification Duvernay class rigs improved, Operating Revenue per Billable Day declined for the three and six months ended June 30, 2019, as the newly acquired Cardium class rig, which worked at a lower day rate and also has a significantly lower capital investment, decreased the average day rate in the United States.

Production Services

Financial Highlights (stated in thousands)	Three months ended June 30 2019	2018	Change	Six months ended June 30 2019	2018	Change
Revenue						
Operating Revenue[1]	9,559	9,227	4%	25,539	24,962	2%
Third party charges	612	435	41%	1,062	1,138	(7%)
Total revenue	10,171	9,662	5%	26,601	26,100	2%
Expenses						
Operating						
Cash operating expenses	9,659	8,191	18%	23,041	20,301	13%
Depreciation	3,179	3,163	1%	6,374	6,443	(1%)
Stock based compensation	22	57	(61%)	43	61	(30%)
Total operating expenses	12,860	11,411	13%	29,458	26,805	10%
Administrative						
Cash administrative expenses	1,149	1,260	(9%)	2,384	2,624	(9%)
Depreciation	136	101	35%	270	170	59%
Stock based compensation	-	4	(100%)	-	15	(100%)
Total administrative expenses	1,285	1,365	(6%)	2,654	2,809	(6%)
Gross Margin[1]	512	1,471	(65%)	3,560	5,799	(39%)
Gross margin as a percentage of Operating Revenue	5%	16%	(69%)	14%	23%	(39%)
Adjusted EBITDA[1]	(637)	211	(402%)	1,176	3,175	(63%)
Adjusted EBITDA as a percentage of Operating Revenue	(7%)	2%	(450%)	5%	13%	(62%)
Operating Loss[1]	(3,952)	(3,053)	29%	(5,468)	(3,438)	59%
Capital expenditures	431	505	(15%)	697	1,387	(50%)
Operating Highlights						
Canadian well servicing rig fleet:						
Average active rig count[1]	13.0	10.5	24%	18.0	15.5	16%
End of period	63	66	(5%)	63	66	(5%)
Service rig Operating Revenue per Service Hour[1]	655	723	(9%)	665	710	(6%)
Service Hours[1]	11,646	9,588	21%	32,144	28,064	15%
Service rig utilization [1]	20%	16%	25%	28%	23%	22%

(1) See "Non-IFRS Measures" on page 19 of this MD&A.

The Company's production services segment includes Eagle's well servicing fleet and Aero's oilfield rental equipment in Canada, as well as Western Oilfield Services' well servicing fleet in the United States. Operating Revenue in the production services segment for the quarter ended June 30, 2019 increased by $0.4 million (or 4%) to $9.6 million, compared to $9.2 million in the same period of the prior year. In the second quarter of 2019, Eagle's contribution to Operating Revenue in the production services segment increased to $7.6 million compared to $6.9 million in the prior year, whereas Aero's contribution to Operating Revenue in the production services segment decreased to $1.9 million compared to $2.3 million in the same period of the prior year. Operating Revenue in the production services segment for the six months ended June 30, 2019 increased by $0.5 million (or 2%) to $25.5 million, compared to $25.0 million in the same period of the prior year. For the six months ended June 30, 2019, Eagle's contribution to Operating Revenue in the production services segment increased to $21.4 million compared to $19.9 million in the prior year, whereas Aero's contribution to Operating Revenue in the production services segment decreased to $4.1 million compared to $5.0 million in the prior year. The increase in Operating Revenue for Eagle for the three and six months ended June 30, 2019, as compared to the same periods in the prior year, reflects an increased market share and is due to continued efforts by management to improve activity with existing customers and broaden the Company's customer base, despite customer programs being impacted by continued market uncertainty. The decrease in Aero's Operating Revenue for the three and six months ended June 30, 2019, as compared to the same periods in the prior year, is mainly due to lower industry activity. Operations commenced in Western Oilfield Services in the United States in the second quarter of 2019, with the first well servicing hours worked near the end of the period.

Eagle's Service Hours improved by 21% to 11,646 hours (20% utilization) in the second quarter of 2019, as compared to 9,588 hours (16% utilization) in the same period of the prior year. Similarly for the six months ended June 30, 2019, Eagle's Service Hours increased by 15% to 32,144 hours (28% utilization) compared to 28,064 hours (23% utilization) in the same period of the prior year. The improvement in Eagle's Service Hours is mainly due to the continued efforts by management to increase market share. While utilization improved, service rig Operating Revenue per Service Hour decreased by 9% to $655 and 6% to $665 for the three and six months ended June 30, 2019 respectively, as compared to the same periods in the prior year, due to pricing pressure in certain operating areas.

Adjusted EBITDA decreased in the second quarter of 2019 by $0.8 million to a loss of $0.6 million, compared to a gain of $0.2 million in the second quarter of 2018. While Operating Revenue increased by 4%, the lower Adjusted EBITDA for the three months ended June 30, 2019, was mainly due to additional costs of $0.4 million related to establishing well servicing in the Bakersfield area of California in the United States in 2019 and higher operating costs related to repairs and maintenance in Canada, partially due to reactivating rigs. Similarly, for the six months ended June 30, 2019, Adjusted EBITDA decreased by $2.0 million (or 63%), as higher activity in Eagle, was offset by higher operating costs in Eagle and lower activity in Aero, coupled with $0.8 million related to establishing well servicing operations in the Bakersfield area of California.

During the three and six months ended June 30, 2019, cash administrative expenses, which exclude depreciation and stock based compensation, totalled $1.1 million and $2.4 million respectively, and were both 9% lower than the same periods in the prior year, mainly due to lower rent expense due to the impact of adopting IFRS 16.

Depreciation expense for the three and six months ended June 30, 2019 was consistent with the same periods of the prior year, as capital assets additions, including leases capitalized with the adoption of IFRS 16, were offset by certain capital assets being fully depreciated in the period.

Capital expenditures in the production services segment totalled $0.4 million in the second quarter of 2019, as compared to $0.5 million in the same period of the prior year, and mainly relate to maintenance capital. During the six months ended June 30, 2019, capital expenditures in the production services segment totalled $0.7 million, as compared to $1.4 million in the same period of the prior year, and included $0.2 million of expansion capital and maintenance capital of $0.5 million.

Corporate

	Three months ended June 30			Six months ended June 30		
(stated in thousands)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Administrative						
Cash administrative expenses	878	1,094	(20%)	1,886	2,467	(24%)
Depreciation	459	128	259%	908	263	245%
Stock based compensation	82	213	(62%)	190	426	(55%)
Total administrative expenses	1,419	1,435	(1%)	2,984	3,156	(5%)
Finance costs	4,700	4,493	5%	9,376	9,873	(5%)
Other items	61	(10)	(710%)	(317)	(97)	227%
Income taxes						
Current tax recovery	-	(45)	(100%)	-	(45)	(100%)
Deferred tax recovery	(8,807)	(5,108)	72%	(11,329)	(6,350)	78%
Total income taxes	(8,807)	(5,153)	71%	(11,329)	(6,395)	77%
Operating Loss(1)	(1,337)	(1,222)	9%	(2,794)	(2,730)	2%

(1) See "Non-IFRS Measures" on page 19 of this MD&A.

Corporate cash administrative expenses, which exclude depreciation and stock based compensation, for the three and six months ended June 30, 2019 decreased by 20% and 24% respectively, as compared to the same periods in the prior year and totalled $0.9 million and $1.9 million respectively. The decrease for both the three and six months ended June 30, 2019 is mainly due to lower employee related costs and lower rent expense as a result of the adoption of IFRS 16.

Finance costs of $4.7 million for the quarter ended June 30, 2019, were higher by $0.2 million (or 5%) as compared to the same period in the prior year, and represented an effective interest rate of 8.1%, as compared to 8.3% in the same period of the prior year. The increase in finance costs in the second quarter of 2019 is mainly due to a higher average long term debt balance in the period, due to an increased average Credit Facility balance outstanding and the finance lease obligations recognized on the adoption of IFRS 16. For the six months ended June 30, 2019, finance costs of $9.4 million were lower by $0.5 million (or 5%) than the same period of the prior year and represented an effective interest rate of 8.0%, as compared to 8.8% in the same period of the prior year. The decrease for the six months ended June 30, 2019 is mainly due to the inclusion of $0.6 million of non-cash accretion expense related to the early redemption of the Company's senior notes in 2018, offset partially by a higher average long term debt balance outstanding in 2019.

Other items, which relate to gains and losses on the sale of assets and foreign exchange, total a loss of $0.1 million and a gain of $0.3 million respectively, for the three and six months ended June 30, 2019 as compared to a negligible gain and a gain of $0.1 million respectively, in the same periods of the prior year.

For the second quarter of 2019, income taxes on a consolidated basis totalled a recovery of $8.8 million, representing an effective tax rate of 46.5%, as compared to an effective tax rates of 25.0% in the second quarter of 2018. For the six month period ended June 30, 2019, income taxes on a consolidated basis totalled a recovery of $11.3 million, representing an effective tax rate of 39.7%, as compared to an effective tax rate of 23.0% in the same period of 2018. The increase in the effective tax rate for both the three and six months ended June 30, 2019, as compared to the same periods of the prior year, is mainly due to the decrease in the Alberta corporate tax rate substantively enacted in the second quarter of 2019. Normalizing for this change, the effective tax rate for the three and six months ended June 30, 2019 would have been approximately 20.8% and 22.6% respectively.

Liquidity and Capital Resources

The Company's liquidity needs in the short and long term can be sourced in several ways including: available cash balances, funds from operations, borrowing against the Credit Facilities, new debt instruments, equity issuances and proceeds from the sale of assets. As at June 30, 2019, Western had working capital of $5.0 million, a decrease of $10.7 million from December 31, 2018. Western's consolidated debt balance at June 30, 2019 increased by $3.6 million (or 2%) to $231.2 million, as compared to $227.6 million at December 31, 2018, mainly due to the implementation of IFRS 16, Leases, which added $12.8 million to long term debt, which was partially offset by repayments related to the Company's Credit Facilities and its Second Lien Facility.

During the six months ended June 30, 2019, Western had the following changes to its cash balances, which resulted in a $1.3 million decrease in cash and cash equivalents in the period:

Cash and cash equivalents (stated in thousands)	
Opening balance, at December 31, 2018	3,960
Add:	
Adjusted EBITDA	13,686
Change in non cash working capital	6,456
Proceeds on sale of property and equipment	711
Deduct:	
Finance costs paid	(8,839)
Repayment of Credit Facilities	(6,727)
Additions to property and equipment	(3,883)
Repayment of Second Lien Facility	(1,075)
Repayment of other long term debt	(1,597)
Other items	(10)
Ending balance, at June 30, 2019	**2,682**

Western's Credit Facilities, which have a limit of $60.0 million, mature on December 17, 2021. Western's cash from operations and available Credit Facilities are expected to be sufficient to cover Western's financial obligations, including working capital requirements and the 2019 capital budget. Advances under the Credit Facilities are limited by the Company's borrowing base. The borrowing base is applicable when either (i) more than $40.0 million is drawn on the Credit Facilities or (ii) the net book value of Western's property and equipment is less than $300.0 million. The borrowing base is determined as follows:

- 85% of eligible investment grade accounts receivable; plus
- 75% of eligible non-investment grade accounts receivable; plus
- 25% of the net book value of property and equipment to a maximum of $40.0 million.

As at June 30, 2019, the borrowing base calculation was not applicable as less than $40.0 million was drawn on the Company's Credit Facilities and the net book value of Western's property and equipment was greater than $300.0 million.

Amounts borrowed under the Credit Facilities bear interest at the bank's Canadian prime rate or the banker's acceptance rate plus an applicable margin depending, in each case, on the ratio of Consolidated Debt to Consolidated EBITDA as defined by the Credit Facilities agreement. Consolidated EBITDA, as defined by the Credit Facilities agreement, differs from Adjusted EBITDA as defined under Non-IFRS Measures on page 19 of this MD&A, by including certain items such as realized foreign exchange gains or losses and cash payments made on leases capitalized under IFRS 16.

The Credit Facilities are secured by the assets of Western and its subsidiaries. A summary of the Company's financial covenants as at June 30, 2019 is as follows:

June 30, 2019	**Covenants [1]**
Maximum Consolidated Senior Debt to Consolidated EBITDA Ratio	3.0:1.0 or less
Maximum Consolidated Debt to Consolidated Capitalization Ratio	0.6:1.0 or less
Minimum Current Ratio	1.15:1.0 or more

(1) See covenant definitions in Note 7 of the June 30, 2019 condensed consolidated financial statements.

At June 30, 2019, Western is in compliance with all covenants related to its Credit Facilities. The adoption of IFRS 16 did not have an impact on the Company's Credit Facility covenants.

For the three months ended June 30, 2019, the Company had two customers comprising 13.4% and 10.7% respectively, of the Company's total revenue. The trade receivable balance outstanding related to these customers was 4.8% and 11.3% respectively, of the Company's total trade and other receivables at June 30, 2019. One of the previously mentioned customers was also a significant customer for the six months ended June 30, 2019, comprising 10.0% of the Company's total revenue. For the three months ended June 30, 2018, the Company had three significant customers comprising 14.9%, 12.2% and 10.3% respectively, of the Company's total revenue. For the six months ended June 30, 2018, the Company had no significant customers comprising 10.0% or more of the Company's total revenue. The Company's significant customers may change from period to period.

Summary of Quarterly Results

In addition to other market factors, quarterly results of Western are markedly affected by weather patterns throughout its operating areas. Historically, the first quarter of the calendar year is very active, followed by a much slower second quarter due to what is known in the Canadian oilfield service industry as "spring breakup", where due to the spring thaw, provincial and county road bans restrict movement of heavy equipment. As a result of this, the variation of Western's results on a quarterly basis, particularly between the first and second quarters, can be significant quarter over quarter independent of other demand factors.

The following is a summary of selected financial information of the Company for the last eight completed quarters:

Three months ended (stated in thousands, except per share amounts)	**Jun 30, 2019**	**Mar 31, 2019**	**Dec 31, 2018**	**Sep 30, 2018**	**Jun 30, 2018**	**Mar 31, 2018**	**Dec 31, 2017**	**Sep 30, 2017**
Revenue	37,728	65,775	63,133	58,879	33,141	81,257	66,515	54,131
Operating Revenue(1)	34,692	61,773	57,806	54,071	30,976	72,965	59,255	51,111
Gross Margin(1)	6,792	15,532	12,677	12,025	5,562	20,271	15,886	12,299
Adjusted EBITDA(1)	2,438	11,248	7,916	7,691	897	15,112	10,067	6,882
Cash flow from operating activities	17,501	5,888	5,022	(1,968)	26,313	3,864	(800)	1,609
Net loss	(10,128)	(7,078)	(9,530)	(10,108)	(15,475)	(5,947)	(4,974)	(11,478)
per share - basic	(0.11)	(0.08)	(0.10)	(0.11)	(0.17)	(0.06)	(0.06)	(0.16)
per share - diluted	(0.11)	(0.08)	(0.10)	(0.11)	(0.17)	(0.06)	(0.06)	(0.16)
Total assets	626,890	663,117	667,295	669,079	670,584	706,895	760,504	737,385
Long term debt	223,363	238,590	222,258	222,564	210,944	227,401	265,219	264,958

(1) See "Non-IFRS Measures" on page 19 of this MD&A.

Revenue and Adjusted EBITDA, which were impacted by lower commodity prices throughout the last eight quarters, began to recover in 2017. In 2017 and through to the third quarter of 2018, after normalizing for shortfall commitment revenue, Revenue and Adjusted EBITDA in each quarter increased, as compared to the same quarter in the prior year, due to improving market conditions. However, the fourth quarter of 2018 was impacted by record high differentials on Canadian crude oil and market uncertainty continued into the first half of 2019, resulting in customers reducing or delaying their drilling programs, which had a negative impact on Western's Revenue and Adjusted EBITDA.

Net loss is impacted by the seasonal nature of the oilfield service industry in Canada. A net loss has been incurred throughout the last eight quarters, due to the prolonged decline in crude oil and natural gas prices.

Total assets over the last eight quarters have been impacted by depreciation expense exceeding capital additions as capital spending has been reduced during the downturn in crude oil and natural gas prices.

Commitments

In the normal course of business the Company incurs commitments related to its contractual obligations. The expected maturities of the Company's contractual obligations as at June 30, 2019 are as follows:

(stated in thousands)	2019	2020	2021	2022	2023	Thereafter	Total
Second Lien Facility	1,075	2,150	2,150	2,150	205,325	-	212,850
Second Lien Facility interest	7,662	15,376	15,179	15,105	7,473	-	60,795
Trade payables and other current liabilities (1)	17,400	-	-	-	-	-	17,400
Operating commitments (2)	2,529	921	843	841	816	884	6,834
Revolving Facility	-	-	3,000	-	-	-	3,000
Operating Facility	-	-	2,164	-	-	-	2,164
Finance lease obligations (3)	2,221	4,239	2,962	2,167	1,792	1,860	15,241
Total	30,887	22,686	26,298	20,263	215,406	2,744	318,284

(1) Trade payables and other current liabilities exclude the Company's interest accrued as at June 30, 2019 on the Second Lien Facility.

(2) Operating commitments include purchase commitments, short term operating leases, and operating expenses associated with long term leases.

(3) Finance lease obligations represent the gross lease commitments to be paid over the term of the Company's outstanding long term leases and include those leases capitalized under IFRS 16.

Second Lien Facility and interest:

The Company pays interest on the Second Lien Facility semi-annually on January 1 and July 1. The Second Lien Facility is due January 31, 2023.

Trade payables and other current liabilities:

The Company has recorded trade payables for amounts due to third parties which are expected to be paid within one year.

Operating commitments:

The Company has agreements in place to purchase certain capital and other operational items with third parties, as well as short term leases with a term of less than one year, and operating expense associated with long term leases.

Other long term debt:

The Company has other long term debt relating to leased vehicles, as well as office and equipment leases, classified as lease obligations under IFRS 16, which was adopted January 1, 2019. These leases run for terms greater than one year.

There have been no material changes in the contractual obligations, other than in the normal course of business, subsequent to June 30, 2019.

Outstanding Share Data

	July 24, 2019	June 30, 2019	December 31, 2018
Common shares outstanding	92,307,042	92,307,042	92,305,542
Warrants	7,099,546	7,099,546	7,099,546
Stock options outstanding	7,268,123	7,350,827	8,313,537
Restricted share units outstanding - equity settled	513,358	513,358	543,997

Off Balance Sheet Arrangements

As at June 30, 2019, Western had no off balance sheet arrangements in place.

Transactions with Related Parties

During the three and six months ended June 30, 2019 and 2018, the Company had no transactions with related parties.

Financial Instruments

Fair Values

All financial instruments are measured at fair value upon initial recognition of the transaction. Measurement in subsequent periods is dependent on whether the instrument is classified as “amortized cost”, “fair value through profit or loss”, or “fair value through other comprehensive income”.

The Company derecognizes a financial asset when the contractual right to the cash flows from the asset expires, or it transfers the right to receive the contractual cash flows from the financial asset in a transaction in which substantially all the risks and rewards of ownership of the financial asset are transferred. The Company derecognizes a financial liability when its contractual obligations are discharged, cancelled or expired.

Financial 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 either to settle on a net basis or to realize the asset and settle the liability simultaneously.

The Company has the following financial assets and liabilities recognized at amortized cost:

Cash and cash equivalents are initially recognized at fair value and are subsequently measured at amortized cost with changes therein recognized in net income.

The Company’s trade and other receivables are classified under the amortized cost category and are financial assets with fixed or determinable payments that are not quoted in an active market. Such assets are recognized initially at fair value, adjusted for any directly attributable transaction costs. Subsequent to initial recognition, trade and other receivables are measured at amortized cost using the effective interest method, less any impairment losses.

Trade payables and other current liabilities, finance lease obligations, the Second Lien Facility and Credit Facilities are classified under the amortized cost category. Financial liabilities are recognized initially at fair value net of any directly attributable transaction costs. Financial liabilities, including the Second Lien Facility, are subsequently measured at amortized cost using the effective interest method. Transaction costs incurred with respect to the Credit Facilities are deferred and amortized using the straight line method over the term of the facility. The asset is recognized in other assets on the balance sheet while the amortization is included in finance costs within net income.

Credit Risk

The Company's trade receivables are with customers in the crude oil and natural gas industry and are subject to normal industry credit risk. The Company's practice is to manage credit risk by performing a detailed analysis of the credit worthiness of new customers before the Company's standard payment terms are offered. Additionally, the Company continuously reviews individual customer trade receivables, taking into consideration payment history and the aging of the trade receivable to monitor collectability.

Under IFRS 9, Financial Instruments, the Company is required to review impairment of its trade and other receivables at each reporting period and to review its loss allowance for expected future credit losses. The Company records an allowance for doubtful accounts if an account is determined to be uncollectible. Any provisions recorded by the Company are reviewed regularly to determine if any of the balances provided for should be written off. The allowance for doubtful accounts could materially change as a result of fluctuations in the financial position of the Company's customers.

The Company completes a detailed review of its historical credit losses as part of its impairment assessment. The Company has had minimal historical impairment losses on its trade and other receivables, due in part to its credit management processes. As such, the Company assesses impairment losses on an individual customer account basis, rather than recognize a loss allowance on all outstanding trade and other receivables.

Interest Rate Risk

The Company is exposed to interest rate risk on debt subject to floating interest rates, such as the Company's Credit Facilities. Other long term debt, such as the Second Lien Facility and the Company's finance leases have fixed interest rates, however they are subject to interest rate fluctuations relating to refinancing as required.

Foreign Exchange Risk

The Company is exposed to foreign exchange fluctuations in relation to its US dollar capital expenditures and US operations. The Company ensures that its net exposure is kept to an acceptable level by buying or selling foreign currencies at spot rates when necessary. From time to time the Company may use forward foreign currency contracts to hedge against these fluctuations.

Liquidity Risk

Liquidity risk is the exposure of the Company to the risk of not being able to meet its financial obligations as they become due. To manage liquidity risk, the Company forecasts operational results and capital spending on a regular basis. Variances between actual results and forecast are continually monitored to assess the Company's ability to meet its financial obligations.

Disclosure Controls and Procedures and Internal Controls Over Financial Reporting

As Western's common shares trade on the Toronto Stock Exchange, pursuant to National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings, the President and Chief Executive Officer ("CEO") and Senior Vice President, Finance and Chief Financial Officer ("CFO") of the Company have certified as at June 30, 2019 that they have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") to provide reasonable assurance that: (i) material information relating to the Company, including its consolidated subsidiaries, is made known to the CEO and the CFO by others within those entities, particularly during the periods in which the interim filings of the Company 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 CEO and CFO do not expect that the DC&P will prevent or detect all errors, misstatements and fraud but are designed to provide reasonable assurance of achieving their objectives. A control system, no matter how well designed or operated, can only provide reasonable, but not absolute, assurance that the objectives of the control system are met. In addition to DC&P, the CEO and CFO have designed internal controls over financial reporting, or caused them to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

During the three months ended June 30, 2019, there were no changes in internal control over financial reporting that materially affected, or are reasonably likely to materially affect, Western's internal control over financial reporting.

Change in Accounting Policy

On January 1, 2019, the Company adopted IFRS 16, Leases, using the modified retrospective method. The adoption of IFRS 16 resulted in an increase in long term debt of $12.8 million, an increase in property and equipment of $10.1 million, a decrease in provisions of $1.4 million, a decrease in the deferred tax liability of $0.4 million, a decrease in other assets of $0.1 million, and a net decrease in retained earnings of $1.1 million. For the three and six months ended June 30, 2019, the impact of IFRS 16 on Adjusted EBITDA was an increase of $0.8 million and $1.6 million respectively, whereas the impact on net loss was less than $0.1 million in each respective period, as increased Adjusted EBITDA was offset by higher depreciation and finance costs. There have been no other changes in the Company's accounting policies. The adoption of IFRS 16 is disclosed in Note 4 of the condensed consolidated financial statements as at and for the three and six months ended June 30, 2019.

Critical Accounting Estimates

This MD&A of the Company's financial condition and results of operations is based on the condensed consolidated financial statements for the three and six months ended June 30, 2019, which were prepared in accordance with IFRS. The presentation of these financial statements in conformity with IFRS requires management to make estimates, judgments and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. These estimates and judgements are based on historical experience and on various assumptions that are believed to be reasonable under the circumstances. Anticipating future events cannot occur with absolute certainty, therefore these estimates may change as new events occur, more experience is acquired and as the Company's operating environment changes. The Company's critical accounting estimates relate to business combinations, impairment, property and equipment, income taxes, stock based compensation, and the Company's allowance for doubtful accounts.

The accounting estimates believed to be the most difficult, subjective or require complex judgements and which are the most critical to the reporting of results of operations and financial positions of the Company are as follows:

Impairment

An evaluation of whether or not an asset is impaired involves consideration of whether indicators of impairment exist. Factors which could indicate impairment exists include: significant underperformance of an asset relative to historical or projected operating results, significant changes in the manner in which an asset is used or in the Company's overall business strategy, the carrying amount of the net assets of the entity being more than its market capitalization or significant negative industry or economic trends. In some cases, these events are clear. However, in many cases, a clearly identifiable event indicating possible impairment does not occur. Instead, a series of individually insignificant events occur over a period of time leading to an indication that an asset may be impaired. Events can occur in these situations that may not be known until a date subsequent to their occurrence. Management continually monitors the Company's operating segments, the markets, and the business environment, and makes judgments and assessments about conditions and events in order to conclude whether a possible impairment exists.

When there are indicators of impairment, and at a minimum annually in the case of goodwill, the recoverable amount of the asset is estimated to determine the amount of impairment, if any. Where it is not possible to estimate the recoverable amount of an individual asset, the Company estimates the recoverable amount of the cash generating unit ("CGU") to which the asset belongs. A CGU is the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The determination of CGUs is based on management judgement.

The recoverable amount for property and equipment is the higher of fair value less costs to sell and value in use. In assessing fair value less costs to sell, the Company must estimate the price that would be received to sell the asset or CGU less any incremental costs directly attributable to the disposal. In assessing value in use, the estimated future cash flows are discounted to their present value using an appropriate discount rate that reflects current market assessments of the time value of money and the risks specific to the asset or CGU. Arriving at the estimated future cash flows involves significant judgments, estimates and assumptions, including those associated with the future cash flows of the CGU, determination of the CGU and discount rates.

If indicators conclude that the asset is no longer impaired, the Company will reverse impairment losses on assets only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized. Impairment losses on goodwill are not reversed. Similar to determining if an impairment exists, judgment is required in assessing if a reversal of an impairment loss is required.

Property and equipment

Property and equipment is depreciated over the estimated useful life of the asset while factoring in an asset's estimated residual value as determined by management. All estimates of useful lives and residual values are set out in Note 3 (f) of the December 31, 2018 annual consolidated financial statements. Assessing the reasonableness of the estimated useful life, residual value and the appropriate depreciation methodology requires judgment and is based on management's experience and knowledge of the industry. Additionally, when determining whether to decommission an asset, future utilization and economic conditions are considered based on management's experience and knowledge of the industry and requires management's judgement.

Income taxes

Preparation of the condensed consolidated financial statements involves determining an estimate of, or provision for, income taxes in each of the jurisdictions in which the Company operates. The process also involves making an estimate of taxes currently payable and taxes expected to be payable or recoverable in future periods, referred to as deferred taxes. Deferred taxes result from the effects of temporary differences due to items that are treated differently for tax and accounting purposes. The tax effects of these differences are reflected in the condensed consolidated balance sheet as deferred tax assets and liabilities.

An assessment must also be made to determine the likelihood that the Company's future taxable income will be sufficient to permit the recovery of deferred income tax assets. To the extent that such recovery is not probable, recognized deferred tax assets must be reduced. Judgment is required in determining the provision for income taxes and recognition of deferred tax assets and liabilities. Management must also exercise judgment in its assessment of continually changing tax interpretations, regulations and legislation, to ensure deferred tax assets and liabilities are complete and fairly presented. The effects of differing assessments and applications could be material.

Stock based compensation

The fair values of stock options, equity settled restricted share units ("RSUs"), and warrants are measured using a Black Scholes option pricing model. Measurement inputs include the common share price on the grant date, the exercise price of the instrument, the expected common share price volatility, the weighted average expected life of the instruments, the expected dividends and the risk-free interest rate. Service and non-market performance conditions are not taken into account in determining fair value. Stock based compensation recognized is also determined based on management's grant date estimate of the forfeitures that are expected to occur over the vesting period of the stock options and equity settled RSUs.

Cash settled RSUs outstanding are fair valued using a mark-to-market calculation based on the Company's closing common share price at the end of the period. The number of stock options and RSUs that actually vest could differ from the estimated number of awards expected to vest and any differences between the actual and estimated forfeitures are recognized prospectively as they occur.

Allowance for doubtful accounts

The Company reviews its outstanding trade and other receivables balances on at least a monthly basis to determine collectability. Accounts receivable balances are also reviewed as circumstances change in the economy and/or a customer's credit worthiness changes. An allowance for doubtful accounts is recorded if an account is considered uncollectible.

Business Risks

For a comprehensive listing of the Company's business risks please see the most recent annual information form ("AIF") for the year ended December 31, 2018 as filed on SEDAR at www.sedar.com. Certain of the Company's primary business risks as at June 30, 2019 are as follows:

- The Company's business relies on the crude oil and natural gas exploration and production industry which is subject to a number of risks including general economic conditions, fluctuations in demand and supply of crude oil and natural gas production, fluctuations in commodity prices, competition and increases in operating costs. In addition, changes may occur in government regulations, including regulations relating to foreign acquisitions, prices, taxes, royalties, land tenure, allowable production, importing and exporting of crude oil and natural gas and environmental protection for the crude oil and natural gas industry as a whole. Risks impacting the crude oil and natural gas exploration and production industry, including the ability of crude oil and natural gas companies to accumulate capital or variations in their exploration and development budgets, may also affect the Company's business. The exact impact of these risks cannot be accurately predicted.
- If a low commodity price environment persists, the demand for the Company's equipment and services will remain lower than normal and the Company's utilization rates and revenue will be adversely affected during such time. In addition, lower utilization and revenue could result in the Company not being in compliance with certain covenants in its Credit Facilities, which in turn could restrict the Company's ability to access its Credit Facilities, pay distributions and incur additional debt in the future.

- The Company may find it necessary in the future to obtain additional debt or equity to support ongoing operations, to refinance debt, to undertake capital expenditures or to undertake acquisitions or other business combination transactions. There can be no assurance that additional financing will be available when needed or on terms acceptable to the Company.
- The Company's exploration and production customers' facilities and other operations emit greenhouse gases which requires them to comply with legislation in those provinces and states where they operate. Over the past few years, both Federal and Provincial governments have implemented carbon levies on greenhouse gas emissions. The direct or indirect costs of these new greenhouse gas emission reduction regulations, as well as regulations which may be adopted in these or other jurisdictions in the future, may have a material adverse effect on the Company's business, financial condition and results of operations and cash flows, as well as impacting the Company's customers' operations.
- In addition to global economic events and uncertainty, the capacity within North America to ship commodities to market introduces uncertainties in levels of activity and pricing for crude oil and natural gas production.
- The Company is vulnerable to market prices. Fixed costs, including costs associated with operations, interest, leases, and labour costs account for a significant portion of the Company's expenses. As a result, reduced productivity resulting from reduced demand, equipment failure, or other factors could significantly affect its financial results.
- Competition among oilfield service companies offering related services is significant. Some competitors are larger and have greater revenue than the Company and overall greater financial resources. The Company's ability to generate revenue depends on its ability to attract and win contracts and to perform services.
- Currently, the Company is focused on providing services in the WCSB as well as certain limited geographic areas in the United States, which may expose the Company to more extreme market fluctuations relating to factors such as weather and general economic conditions which may be more extreme than the broader industry conditions.
- The success of the Company is dependent upon the efforts and abilities of its management team. The loss of any member of the management team could have a material adverse effect upon the business and prospects of the Company.
- Safety is a key factor customers consider when selecting an oilfield service company. A decline in the Company's safety performance could result in reduced demand for the Company's services which could have a material adverse effect on the Company's business and financial results.
- The Company's operations are subject to many hazards inherent in the oilfield service industry, such as blowouts, explosions, damaged or lost drilling, well servicing and oilfield rental equipment or damage or loss from inclement weather, which could result in business interruption, casualty losses, damage or destruction of equipment, suspension of operations, environmental damage or damage to property. This could have a material adverse effect on the Company's business and financial results.
- During the prolonged downturn many oilfield service workers left the industry and, therefore, as activity has increased it has been difficult for the Company to attract and retain field crews. This could have a material adverse effect on the Company's business and financial results.
- The Company's business is subject to the operating risks inherent to the oilfield service industry. On occasion, substantial liabilities to third parties may be incurred. The Company will have the benefit of insurance maintained by it and industry standard contracts, however, it may become liable for damages against which it cannot adequately insure or against which it may elect not to insure because of high costs or other reasons.
- The ability of the Company to make payments, dividends or enter into certain transactions will be subject to the applicable laws and contractual restrictions in the instruments governing its indebtedness, including the Credit Facilities and the Second Lien Facility.
- The oilfield service industry has experienced a high degree of invention and innovation. It is possible that new technology will be developed which will compete with the Company's products and services.
- A portion of the operations of the Company are in the United States which subject the Company to currency fluctuations and different tax and regulatory laws.
- The loss of a significant customer or customers, or any decrease in services provided or prices charged to a significant customer or customers could have a material adverse effect on the Company's business and financial results.

- The Company's business is subject to credit risk primarily from credit exposure to customers, with a concentration of credit risk with customers in the crude oil and natural gas industry.
- The Company relies on various information systems to manage its business. If these systems were compromised as a result of a successful cyber-attack, this could have a material adverse effect on the Company business and financial results.

Non-IFRS Measures

Western uses certain measures in this MD&A which do not have any standardized meaning as prescribed by IFRS. These measures, which are derived from information reported in the condensed consolidated financial statements, may not be comparable to similar measures presented by other reporting issuers. These measures have been described and presented in this MD&A in order to provide shareholders and potential investors with additional information regarding the Company. These Non-IFRS measures are identified and defined as follows:

Operating Revenue

Management believes that Operating Revenue is a useful supplemental measure as it provides an indication of the revenue generated by Western's principal operating activities, excluding flow through third party charges such as rig fuel, which at the customer's request may be paid for initially by Western, then recharged in its entirety to Western's customers. The closest IFRS measure would be revenue.

Gross Margin

Management believes that Gross Margin is a useful supplemental measure as it provides an indication of the results generated by Western's principal operating activities prior to considering administrative expenses, depreciation and amortization, stock based compensation, how those activities are financed, the impact of foreign exchange, how the results are taxed, how funds are invested, and how non-cash items and one-time gains and losses affect results. The closest IFRS measure would be net income.

The following table provides a reconciliation of revenue under IFRS, as disclosed in the condensed consolidated statements of operations and comprehensive income, to Operating Revenue and Gross Margin:

	Three months ended June 30		Six months ended June 30	
(stated in thousands)	**2019**	**2018**	**2019**	**2018**
Operating Revenue				
Drilling	25,184	21,791	71,068	79,141
Production services	9,559	9,227	25,539	24,962
Less: inter-company eliminations	(51)	(42)	(142)	(162)
	34,692	**30,976**	**96,465**	**103,941**
Third party charges	3,042	2,165	7,050	10,457
Less: inter-company eliminations	(6)	-	(12)	-
Revenue	**37,728**	**33,141**	**103,503**	**114,398**
Less: operating expenses	(46,835)	(44,081)	(112,862)	(121,566)
Add:				
Depreciation - operating	15,817	16,313	31,550	32,704
Stock based compensation - operating	82	189	133	297
Gross Margin	**6,792**	**5,562**	**22,324**	**25,833**

Adjusted EBITDA

Management believes that earnings before interest and finance costs, taxes, depreciation and amortization, other non-cash items and one-time gains and losses ("Adjusted EBITDA") is a useful supplemental measure as it provides an indication of the results generated by the Company's principal operating segments similar to Gross Margin but also factors in the cash administrative expenses incurred in the period. The closest IFRS measure would be net income.

Operating Earnings (Loss)

Management believes that Operating Earnings (Loss) is a useful supplemental measure as it provides an indication of the results generated by the Company's principal operating segments similar to Adjusted EBITDA but also factors in the depreciation expense incurred in the period. The closest IFRS measure would be net income.

The following table provides a reconciliation of net loss under IFRS, as disclosed in the condensed consolidated statements of operations and comprehensive income, to earnings before interest and finance costs, taxes, depreciation and amortization ("EBITDA"), Adjusted EBITDA and Operating Loss:

	Three months ended June 30		Six months ended June 30	
(stated in thousands)	**2019**	**2018**	**2019**	**2018**
Net loss	**(10,128)**	**(15,475)**	**(17,206)**	**(21,422)**
Add:				
Finance costs	4,700	4,493	9,376	9,873
Income tax recovery	(8,807)	(5,153)	(11,329)	(6,395)
Depreciation - operating	15,817	16,313	31,550	32,704
Depreciation - administrative	655	286	1,298	545
EBITDA	**2,237**	**464**	**13,689**	**15,305**
Add:				
Stock based compensation - operating	82	189	133	297
Stock based compensation - administrative	58	254	181	504
Other items	61	(10)	(317)	(97)
Adjusted EBITDA	**2,438**	**897**	**13,686**	**16,009**
Less:				
Depreciation - operating	(15,817)	(16,313)	(31,550)	(32,704)
Depreciation - administrative	(655)	(286)	(1,298)	(545)
Operating Loss	**(14,034)**	**(15,702)**	**(19,162)**	**(17,240)**

Defined Terms:

Average active rig count (contract drilling): Calculated as drilling rig utilization – Billable Days multiplied by the average number of drilling rigs in the Company's fleet for the period.

Average active rig count (production services): Calculated as service rig utilization multiplied by the average number of service rigs in the Company's fleet for the period.

Billable Days: Defined as Operating Days plus rig mobilization days.

Drilling rig utilization – Operating Days (or "Drilling Rig Utilization"): Calculated based on Operating Days divided by total available days.

Drilling rig utilization – Billable Days: Calculated based on Billable Days divided by total available days.

Operating Days: Defined as contract drilling days, calculated on a spud to rig release basis.

Service Hours: Defined as well servicing hours completed.

Service rig utilization: Calculated based on Service Hours divided by available hours, being 10 hours per day, per well servicing rig, 365 days per year.

Contract Drilling Rig Classifications:

Cardium class rig: Defined as any contract drilling rig which has a total hookload less than or equal to 399,999 lbs (or 177,999 daN).

Montney class rig: Defined as any contract drilling rig which has a total hookload between 400,000 lbs (or 178,000 daN) and 499,999 lbs (or 221,999 daN).

Duvernay class rig: Defined as any contract drilling rig which has a total hookload equal to or greater than 500,000 lbs (or 222,000 daN).

Abbreviations:

- Barrel ("bbl");
- Basis point ("bps"): A 1% change equals 100 basis points and a 0.01% change is equal to one basis point;
- Canadian Association of Oilwell Drilling Contractors ("CAODC");
- DecaNewton ("daN");
- International Financial Reporting Standards ("IFRS");
- Pounds ("lbs");
- Thousand cubic feet ("mcf");
- Western Canadian Sedimentary Basin ("WCSB");

- Western Canadian Select (“WCS”); and
- West Texas Intermediate (“WTI”).

Forward-Looking Statements and Information

This MD&A contains certain statements or disclosures relating to Western that are based on the expectations of Western as well as assumptions made by and information currently available to Western which may constitute forward-looking information under applicable securities laws. All information and statements contained herein that are not clearly historical in nature constitute forward-looking information, and words and phrases such as “may”, “will”, “should”, “could”, “expect”, “intend”, “anticipate”, “believe”, “estimate”, “plan”, “predict”, “potential”, “continue”, “looking to”, or the negative of these terms or other comparable terminology are generally intended to identify forward-looking information. Such information represents the Company’s internal projections, estimates or beliefs concerning, among other things, an outlook on the estimated amounts and timing of capital expenditures, anticipated future debt levels and revenues or other expectations, beliefs, plans, objectives, assumptions, intentions or statements about future events or performance. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information.

In particular, forward-looking information in this MD&A includes, but is not limited to, statements relating to commodity pricing; the future demand for and utilization of the Company’s services and equipment; the pricing for the Company’s services and equipment; the terms of existing and future drilling contracts in Canada and the US and the revenue resulting therefrom (including the number of Billable Days typically generated from such contracts and expected expiration dates of such contracts); the Company’s expansion and maintenance capital plans for 2019 and its ability to make changes thereto in response to customer demands; the Company’s liquidity needs including the ability of current capital resources to cover Western’s financial obligations, working capital requirements and the 2019 capital budget; the use, availability and sufficiency of the Company’s Credit Facilities; pricing for Western’s services and impact on Adjusted EBITDA; the Company’s ability to maintain certain covenants under its Credit Facilities; the future declaration of dividends; expectations as to the increase in crude oil transportation capacity through pipeline development; expectations as to the benefits of the liquefied natural gas expansion in British Columbia on the Company and its rig fleet; the future deployment or retirement of rigs and other existing assets; the potential impact of changes to laws, governmental and environmental regulations, and the price on carbon emissions; the expectation of continued investment in the Canadian crude oil and natural gas industry; the development of Alberta and British Columbia resource plays; expectations relating to producer spending and activity levels for oilfield services; the Company’s approach to management of its budget and operations; the Company’s ability to maintain a competitive advantage to enable it to manage the current oilfield service environment; the Company’s ability to find and maintain enough field crew members; and forward-looking statements under the headings “Disclosure Controls and Procedures and Internal Controls Over Financial Reporting”, “Business Risks” and “Critical Accounting Estimates”.

The material assumptions in making the forward-looking statements in this MD&A include, but are not limited to, assumptions relating to: demand levels and pricing for oilfield services; demand for crude oil and natural gas and the price and volatility of crude oil and natural gas; pressures on commodity pricing; the continued business relationships between the Company and its significant customers; the Company’s competitive advantage; crude oil transport and pipeline approval and development; the Company’s ability to finance its operations; the effectiveness of the Company’s cost structure and capital budget; the effects of seasonal and weather conditions on operations and facilities; the competitive environment to which the various business segments are, or may be, exposed in all aspects of their business and the Company’s competitive position therein; the ability of the Company’s various business segments to access equipment (including spare parts and new technologies); changes in laws or regulations; currency exchange fluctuations; the ability of the Company to attract and retain skilled labour and qualified management; the ability to retain and attract significant customers; the ability to maintain a satisfactory safety record; and general business, economic and market conditions.

Although Western believes that the expectations and assumptions on which such forward-looking statements and information are based on are reasonable, undue reliance should not be placed on the forward-looking statements and information as Western cannot give any assurance that they will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risk that recent improvements in commodity pricing may not continue, and other general industry, economic, market and business conditions. Readers are cautioned that the foregoing list of risks, uncertainties and assumptions are not exhaustive. Additional information on these and other risk factors that could affect Western’s operations and financial results are discussed under the heading “Risk Factors” in Western’s annual information form for the year ended December 31, 2018 (“AIF”) which may be accessed through the SEDAR website at www.sedar.com. The forward-looking statements and information contained in this MD&A are made as of the date hereof and Western does not undertake any obligation to update publicly or revise any forward-looking statements and information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

Additional data

The AIF containing additional information relating to the Company is filed on SEDAR at www.sedar.com.