Third Quarter 2018 Interim Report   Date: October 24, 2018

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, 2017 and 2016, the Company's management discussion and analysis ("MD&A") for the year ended December 31, 2017, as well as the condensed consolidated financial statements and notes as at and for the three and nine months ended September 30, 2018 and 2017. This Management Discussion and Analysis ("MD&A") is dated October 24, 2018. All amounts are denominated in Canadian dollars (CDN$) unless otherwise identified.

Financial Highlights	**Three months ended September 30**			**Nine months ended September 30**		
(stated in thousands, except share and per share amounts)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Revenue	58,879	54,131	9%	173,277	171,660	1%
Operating Revenue[1]	54,071	51,111	6%	158,012	159,733	(1%)
Gross Margin[1]	12,025	12,299	(2%)	37,858	42,424	(11%)
Gross Margin as a percentage of Operating Revenue	22%	24%	(8%)	24%	27%	(11%)
Adjusted EBITDA[1]	7,691	6,882	12%	23,700	25,628	(8%)
Adjusted EBITDA as a percentage of Operating Revenue	14%	13%	8%	15%	16%	(6%)
Cash flow from operating activities	(1,968)	1,609	(222%)	28,209	25,441	11%
Capital expenditures	3,776	6,349	(41%)	13,858	12,220	13%
Net loss	(10,108)	(11,478)	(12%)	(31,530)	(32,471)	(3%)
-basic net loss per share	(0.11)	(0.16)	(31%)	(0.34)	(0.44)	(23%)
-diluted net loss per share	(0.11)	(0.16)	(31%)	(0.34)	(0.44)	(23%)
Weighted average number of shares						
-basic	92,236,159	73,877,203	25%	92,197,414	73,823,970	25%
-diluted	92,236,159	73,877,203	25%	92,197,414	73,823,970	25%
Outstanding common shares as at period end	92,304,538	73,974,594	25%	92,304,538	73,974,594	25%
Operating Highlights[1]						
Contract Drilling						
Canadian Operations						
Average active rig count	20.6	20.2	2%	19.6	20.3	(3%)
Operating Revenue per Billable Day	17,961	16,825	7%	18,704	17,109 [3]	9%
Operating Revenue per Operating Day	19,712	18,604	6%	20,680	18,862 [3]	10%
Drilling rig utilization - Billable Days	41%	40%	2%	39%	40%	(3%)
Drilling rig utilization - Operating Days	38%	36%	6%	35%	36%	(3%)
CAODC industry average utilization - Operating Days[2]	30%	29%	3%	29%	29%	-
United States Operations						
Average active rig count	3.4	3.3	3%	2.9	2.8	4%
Operating Revenue per Billable Day (US$)	19,634	19,801	(1%)	20,493	19,763	4%
Operating Revenue per Operating Day (US$)	21,951	21,832	1%	22,812	22,850	-
Drilling rig utilization - Billable Days	56%	65%	(14%)	49%	56%	(13%)
Drilling rig utilization - Operating Days	50%	59%	(15%)	44%	48%	(8%)
Production Services						
Average active rig count	16.3	17.7	(8%)	15.8	17.3	(9%)
Service rig Operating Revenue per Service Hour	653	629	4%	690	661	4%
Service rig utilization	25%	27%	(7%)	24%	26%	(8%)

(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 $6.4 million for the nine months ended September 30, 2017.

Financial Position at (stated in thousands)	September 30, 2018	December 31, 2017	September 30, 2017
Working capital	18,694	62,866	46,184
Property and equipment	620,169	652,828	663,542
Total assets	669,079	760,504	737,385
Long term debt	222,564	265,219	264,958

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. Financial and operating results for Horizon and Stoneham are included in Western's contract drilling segment, while financial and operating results for Eagle and Aero are included in Western's production services segment. Non-International Financial Reporting Standards ("Non-IFRS") measures are defined on page 19 of this MD&A. Abbreviations for standard industry terms are included on page 21 of this MD&A.

Western has a drilling rig fleet of 56 rigs specifically suited for drilling complex horizontal wells. Western is currently the fifth largest drilling contractor in Canada, based on the Canadian Association of Oilwell Drilling Contractors ("CAODC") registered rigs, with a fleet of 50 rigs operating through Horizon. Of the Canadian fleet, 23 are classified as Cardium class rigs, 19 as Montney class rigs and eight 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 six drilling rigs operating through Stoneham, including five Duvernay class triple drilling rigs. Western is also the fifth largest well servicing company in Canada with a fleet of 66 rigs operating through Eagle. 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 nine months ended September 30, 2018 and 2017.

	Three months ended September 30			Nine months ended September 30		
	2018	2017	Change	2018	2017	Change
Average crude oil and natural gas prices(1)(2)						
Crude Oil						
West Texas Intermediate (US$/bbl)	69.61	48.16	45%	67.05	49.32	36%
Western Canadian Select (CDN$/bbl)	54.33	47.27	15%	55.06	49.62	11%
Natural Gas						
30 day Spot AECO (CDN$/mcf)	1.26	1.65	(24%)	1.51	2.40	(37%)
Average foreign exchange rates(2)						
US dollar to Canadian dollar	1.31	1.25	5%	1.29	1.31	(2%)

(1) See "Abbreviations" on page 21 of this MD&A.

(2) Source: Bloomberg

West Texas Intermediate ("WTI") on average improved in the third quarter of 2018 as compared to the second quarter of 2018, increasing by 2%, and was 45% higher compared to the same period in the prior year. Similarly, WTI on average improved in the nine months ended September 30, 2018 by 36% as compared to the same period in the prior year. For Western's Canadian customers, the impact of the US dollar when translating WTI into the Canadian dollar equivalent, resulted in a 51% and 34% increase respectively, for the three and nine months ended September 30, 2018, as compared to the same periods in the prior year. Canadian heavy crude pricing weakened in the third quarter of 2018, as Western Canadian Select ("WCS") on average decreased by 16% as compared to the second quarter of 2018, however improved by 15% as compared to the same period of the prior year. Similarly, WCS improved by 11% in the nine months ended September 30, 2018, as compared to the nine months ended September 30, 2017. Natural gas prices declined in the three and nine months ended September 30, 2018, as the 30 day spot AECO price decreased by 24% and 37% respectively, over the same periods of the prior year, however third quarter 2018 average AECO prices improved marginally by 3% as compared to the second quarter of 2018.

Improved market conditions in 2018 have led to a corresponding increase in the demand for oilfield services in the United States. As reported by Baker Hughes, a GE Company, the average number of active drilling rigs in the United States increased approximately 11% and 18% respectively, for the three and nine months ended September 30, 2018 as compared to the same periods in the prior year. Market conditions in Canada have not improved to the same extent. Higher WTI prices have been largely offset by increased differentials on Canadian crude oil and lower natural gas prices, combined with 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. These factors 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") increased by approximately 12% and 1% respectively, for the three and nine months ended September 30, 2018, as compared to the same periods in the prior year.

Operational results for the three months ended September 30, 2018 include:

- Third quarter Operating Revenue improved by $3.0 million to $54.1 million in 2018 as compared to $51.1 million in 2017. In the contract drilling segment, Operating Revenue totalled $42.0 million in the third quarter of 2018, an increase of $3.3 million (or 9%) as compared to $38.7 million in the third quarter of 2017. In the production services segment, Operating Revenue totalled $12.1 million for the three months ended September 30, 2018, as compared to $12.4 million in the three months ended September 30, 2017, a decrease of $0.3 million (or 3%). While activity was lower in the production services segment, improved pricing in Canada, as well as higher activity in the contract drilling segment impacted Operating Revenue as described below:
    - While Canadian crude oil differentials have increased, absolute prices for Canadian crude oil have improved. As such, drilling rig utilization – Operating Days ("Drilling Rig Utilization") in Canada averaged 38% in the third quarter of 2018 compared to an average of 36% in the third quarter of 2017, reflecting a 200 basis points ("bps") increase. The increase in activity is attributable to improved demand for Western's Cardium and Duvernay class rigs, in addition to Western's already well utilized Montney class rigs. As a result, third quarter 2018 Drilling Rig Utilization of 38% represented a premium of 800 bps to the CAODC industry average of 30%, an increase as compared to the third quarter of 2017 when Drilling Rig Utilization of 36% represented a premium of 700 bps to the industry average. Pricing continued to increase and resulted in a 7% improvement in Operating Revenue per Billable Day in the third quarter of 2018, as compared to the same period in the prior year. The increase in pricing is a result of the Company being successful in steadily raising rates over the last twelve months as the energy industry continues to recover from a multi-year downturn;
    - In the United States, improved WTI prices led to five of the Company's six drilling rigs operating during the quarter, three of which were working on long term contracts. As a result, Operating Days increased by 2% in the third quarter of 2018 as compared to the same period in the prior year. While activity increased, Drilling Rig Utilization decreased to 50% in the third quarter of 2018, compared to 59% in the same period of the prior year, due to an increased rig fleet as one Cardium class drilling rig from the Canadian fleet was transferred to the United States fleet in late 2017. Operating Revenue per Billable Day was relatively consistent during the third quarter of 2018, decreasing by 1% as compared to the third quarter of 2017, as day rate increases on contracted rigs offset changes in the average rig mix; and
    - Service rig utilization was 25% in the third quarter of 2018 compared to 27% in the same period of the prior year. The decrease is due to lower demand in a number of areas where the Company operates as customers deferred work amid widening crude oil differentials, lack of available crews, and wet weather in the latter part of the quarter which impacted customer programs. Hourly rates improved during the third quarter of 2018, increasing by 4% as compared to the same period in the prior year, due to the Company actively increasing hourly rates and changes in the average rig mix. Lower utilization, offset partially by improved pricing, led to a $0.5 million (or 5%) decrease in well servicing Operating Revenue in the period.
- Third quarter Adjusted EBITDA increased by $0.8 million (or 12%) to $7.7 million in the third quarter of 2018 as compared to $6.9 million in the third quarter of 2017. The year over year change in Adjusted EBITDA is due to improved pricing in Canada, as well as higher activity in the contract drilling segment, which was partially offset by lower activity in the production services segment.
- Administrative expenses, excluding depreciation and stock based compensation, decreased by $1.1 million (or 20%) to $4.3 million, as compared to $5.4 million in the third quarter of 2017, mainly due to lower employee related costs.

- The Company incurred a net loss of $10.1 million in the third quarter of 2018 ($0.11 per basic common share) as compared to a net loss of $11.5 million in the same period in 2017 ($0.16 per basic common share). The change can be attributed to the following:
  - A $0.9 million decrease in finance costs, due to lower total debt levels;
  - A $0.8 million increase in Adjusted EBITDA, mainly due to improved pricing in Canada and increased activity in the contract drilling segment; and
  - A $0.1 million decrease in other items, which include gains and losses on foreign exchange and asset sales.

  Offsetting the above mentioned items was a $0.5 million decrease in income tax recovery due to improved earnings before taxes.
- Third quarter 2018 capital expenditures of $3.8 million included $1.6 million of expansion capital and $2.2 million of maintenance capital. In total, capital spending in the third quarter of 2018 decreased by $2.5 million from the $6.3 million incurred in the third quarter of 2017. The Company incurred expansion capital mainly related to drilling rig upgrades, as well as required maintenance capital, in the third quarter of 2018.

Operational results for the nine months ended September 30, 2018 include:

- Operating Revenue for the nine month period ended September 30, 2018 decreased by $1.7 million (or 1%) to $158.0 million as compared to $159.7 million for the nine month period ended September 30, 2017. However, after normalizing for $6.4 million of shortfall commitment revenue recognized in the first quarter of 2017, Operating Revenue for the nine months ended September 30, 2018 improved by $4.7 million (or 3%). In the contract drilling segment, Operating Revenue totalled $121.2 million for the nine months ended September 30, 2018, which after normalizing for $6.4 million of shortfall commitment revenue recognized in 2017, resulted in Operating Revenue improving by $6.8 million (or 6%). In the production services segment, Operating Revenue totalled $37.1 million for the nine months ended September 30, 2018, as compared to $39.1 million in the same period of the prior year, a decrease of $2.0 million (or 5%). While on a year to date basis activity was lower in Canada, pricing in all divisions improved which impacted Operating Revenue as described below:
  - Drilling Rig Utilization in Canada for the nine month period ended September 30, 2018 averaged 35%, compared to an average of 36% for the nine month period ended September 30, 2017, reflecting a 100 bps decrease. The decrease in activity is due to some of Western's customers deferring their drilling plans amid high differentials on Canadian crude oil and low natural gas prices. Drilling Rig Utilization of 35% in 2018 represented a premium of 600 bps to the CAODC industry average of 29%, whereas for the nine months ended September 30, 2017, Drilling Rig Utilization of 36% represented a 700 bps premium to the industry average. The decrease in the Company's utilization premium to the industry average in 2018 is a function of a smaller industry rig fleet, as rigs continue to be decommissioned or moved 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 relatively consistent at 9.9% in the nine months ended September 30, 2018, as compared to 10.4% in the same period of 2017. While utilization decreased during the nine months ended September 30, 2018, pricing continued to increase and resulted in a 9% improvement in Operating Revenue per Billable Day in 2018, as compared to the same period in the prior year. The increase in pricing is due to the Company steadily raising rates over the last twelve months, as the energy industry continues to recover from a multi-year downturn;
  - In the United States, improved WTI prices led to five of the Company's six drilling rigs operating during the period. As a result, Operating Days increased by 9% for the nine months ended September 30, 2018, as compared to the same period in the prior year. While activity increased, Drilling Rig Utilization decreased to 44% for the nine months ended September 30, 2018, as compared to 48% in the same period of the prior year, due to an increased rig fleet as one Cardium class drilling rig from the Canadian fleet was transferred to the United States fleet in late 2017. Operating Revenue per Billable Day in the United States improved by 4% in the nine months ended September 30, 2018, as compared to the same period of the prior year, as the Company has been able to raise day rates as commodity prices improve in the United States; and
  - Service rig utilization of 24% for the nine months ended September 30, 2018 compared to 26% in the same period of the prior year. The decrease is due to customers deferring work amid widening crude oil differentials, lack of available crews, and wet weather in the latter part of the third quarter of 2018. Hourly rates improved for the nine months ended September 30, 2018, increasing by 4% as compared to the same period in the prior year, due to changes in the average rig mix and the Company working to increase rates across all areas. Lower utilization, partially offset by improved pricing, led to a $1.6 million (or 5%) decrease in well servicing Operating Revenue in 2018.

- Adjusted EBITDA for the nine months ended September 30, 2018 decreased by $1.9 million (or 8%) to $23.7 million as compared to $25.6 million for the nine months ended September 30, 2017. However, after normalizing for the $6.4 million in shortfall commitment revenue recognized in the first quarter of 2017, Adjusted EBITDA improved by $4.5 million (or 23%), as compared to the same period in the prior year. The year over year decrease in Adjusted EBITDA is due to lower activity and shortfall commitment revenue in Canada, offset by improved pricing in all divisions and increased activity in the United States.
- Administrative expenses, excluding depreciation and stock based compensation, for the nine month period ended September 30, 2018 decreased by $2.6 million (or 16%) to $14.2 million, as compared to $16.8 million in the same period of the prior year, mainly due to lower employee related costs.
- The Company incurred a net loss of $31.5 million for the nine months ended September 30, 2018 ($0.34 per basic common share) as compared to a net loss of $32.5 million in the same period in 2017 ($0.44 per basic common share). The change can be attributed to the following:
    - A $1.9 million decrease in Adjusted EBITDA, mainly due to lower shortfall commitment revenue; and
    - A $1.7 million decrease in income tax recovery due to improved earnings before taxes.

  Offsetting the above mentioned items was:
    - A $2.1 million positive change in other items, of which $1.6 million related to transaction costs incurred in the prior period, coupled with gains and losses on foreign exchange and asset sales;
    - A $1.9 decrease in finance costs, due to lower total debt levels; and
    - A $0.5 million decrease in stock based compensation expense.
- Year to date capital expenditures of $13.9 million included $7.3 million of expansion capital and $6.6 million of maintenance capital. In total, capital spending for the nine months ended September 30, 2018 increased by $1.7 million from the $12.2 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 2018.
- On January 31, 2018, the Company completed the one time draw of $215.0 million on its 7.25% second lien secured term loan facility (the “Second Lien Facility”). The proceeds from the Second Lien Facility draw, along with cash on hand and funds available under the $70.0 million syndicated revolving credit facility (the “Revolving Facility”) and the $10.0 million committed operating facility (the “Operating Facility” and together the “Credit Facilities”) were used to redeem the $265.0 million 7⅞% senior unsecured notes (the “Senior Notes”) at their par value of $265.0 million on February 1, 2018.

Outlook

Currently, 31 of Western’s drilling rigs are operating. Six of Western’s 56 drilling rigs (or 11%) are under long term take or pay contracts, with one expected to expire in 2018, 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 2018 remains unchanged and is expected to total $20 million with $8 million allocated for expansion capital and $12 million for maintenance capital. Western believes the 2018 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.

Weak natural gas prices in Canada are expected to persist through 2018. While WTI prices are much improved, increased differentials on Canadian crude oil and lower natural gas prices have resulted in the capital budgets for Western’s Canadian customers remaining relatively unchanged in 2018 compared to 2017. As such, year over year activity levels for the remainder of 2018 are expected to remain relatively consistent with 2017. Improving gross margin continues to be a priority for the Company and, as has been demonstrated over the last six quarters, Western is working to implement higher rates with each rig that is awarded work. Prices for Western’s services remain below historical levels and will continue to impact Adjusted EBITDA and cash flow from operating activities in the near term. However, Western’s variable cost structure and a prudent capital budget will aid in preserving balance sheet strength. As at September 30, 2018, Western had $12.0 million drawn on its $80.0 million Credit Facilities, which mature on December 17, 2020 and currently has $213.9 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 including the implementation of a price on carbon emissions in Alberta, 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, as a result of low natural gas prices and differentials on Canadian crude oil, and the increasing challenge of staffing field crews, particularly in the well servicing division. Western's rig fleet is well positioned to benefit from the proposed liquefied natural gas expansion 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 in both Canada and the United States as well as in the production services segment in Canada. 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 September 30**			**Nine months ended September 30**		
(stated in thousands)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Revenue						
Operating Revenue[1]	42,045	38,711	9%	121,186	120,754	-
Third party charges	4,274	2,474	73%	13,593	9,686	40%
Total revenue	46,319	41,185	12%	134,779	130,440	3%
Expenses						
Operating						
Cash operating expenses	36,578	31,851	15%	105,004	98,317	7%
Depreciation	13,152	12,916	2%	39,413	38,914	1%
Stock based compensation	69	15	360%	305	80	281%
Total operating expenses	49,799	44,782	11%	144,722	137,311	5%
Administrative						
Cash administrative expenses	2,218	2,750	(19%)	6,950	8,415	(17%)
Depreciation	59	61	(3%)	172	196	(12%)
Stock based compensation	17	29	(41%)	80	134	(40%)
Total administrative expenses	2,294	2,840	(19%)	7,202	8,745	(18%)
Gross Margin[1]	9,741	9,334	4%	29,775	32,123	(7%)
Gross Margin as a percentage of Operating Revenue	23%	24%	(4%)	25%	27%	(7%)
Adjusted EBITDA[1]	7,523	6,584	14%	22,825	23,708	(4%)
Adjusted EBITDA as a percentage of Operating Revenue	18%	17%	6%	19%	20%	(5%)
Operating Loss[1]	(5,688)	(6,393)	(11%)	(16,760)	(15,402)	9%
Capital expenditures	3,384	5,630	(40%)	12,079	10,543	15%

Operating Highlights						
Canadian Operations						
Contract drilling rig fleet:						
Average active rig count[1]	20.6	20.2	2%	19.6	20.3	(3%)
End of period	50	51	(2%)	50	51	(2%)
Operating Revenue per Billable Day[1]	17,961	16,825	7%	18,704	17,109 [3]	9%
Operating Revenue per Operating Day[1]	19,712	18,604	6%	20,680	18,862 [3]	10%
Operating Days[1]	1,729	1,681	3%	4,841	5,027	(4%)
Number of meters drilled	632,673	541,933	17%	1,551,414	1,478,468	5%
Number of wells drilled	145	160	(9%)	382	407	(6%)
Average Operating Days per well	11.9	10.5	13%	12.7	12.4	2%
Drilling rig utilization - Billable Days[1]	41%	40%	2%	39%	40%	(3%)
Drilling rig utilization - Operating Days[1]	38%	36%	6%	35%	36%	(3%)
CAODC industry average utilization - Operating Days[1][2]	30%	29%	3%	29%	29%	-
United States Operations						
Contract drilling rig fleet:						
Average active rig count[1]	3.4	3.3	3%	2.9	2.8	4%
End of period	6	5	20%	6	5	20%
Operating Revenue per Billable Day (US$)[1]	19,634	19,801	(1%)	20,493	19,763	4%
Operating Revenue per Operating Day (US$)[1]	21,951	21,832	1%	22,812	22,850	-
Operating Days[1]	278	272	2%	718	656	9%
Number of meters drilled	93,259	71,295	31%	229,737	177,376	30%
Number of wells drilled	17	12	42%	44	30	48%
Average Operating Days per well	16.4	22.9	(28%)	16.3	22.0	(26%)
Drilling rig utilization - Billable Days[1]	56%	65%	(14%)	49%	56%	(13%)
Drilling rig utilization - Operating Days[1]	50%	59%	(15%)	44%	48%	(8%)

(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 $6.4 million for the nine months ended September 30, 2017.

For the three months ended September 30, 2018, Operating Revenue in the contract drilling segment totalled $42.0 million, a $3.3 million increase (or 9%), as compared to the same period of the prior year, due to improved activity in Canada and the United States, as well as increased pricing in Canada. For the nine months ended September 30, 2018, Operating Revenue in the contract drilling segment totalled $121.2 million, a $0.4 million increase, as compared to the same period in the prior year. Normalizing for $6.4 million in shortfall commitment revenue in 2017, Operating Revenue for the nine months ended September 30, 2018 increased by $6.8 million (or 6%), as compared to the nine months ended September 30, 2017, as increased pricing in both Canada and the United States and higher activity in the United States, was partially offset by lower activity in Canada.

For the three and nine months ended September 30, 2018, third party charges per Billable Day in the contract drilling segment increased to approximately $1,900 and $2,200 respectively, as compared to approximately $1,100 and $1,500 in the same periods of the prior year. The increase is mainly due to higher fuel prices and an increased volume of fuel purchased, which is recharged to the customer, as more customers elected to purchase fuel through the Company rather than directly from a third party provider in 2018.

For the three months ended September 30, 2018, cash operating expenses per Billable Day in the contract drilling segment, excluding third party charges, increased by 8% to $14,631, as compared to $13,605 in the same period of the prior year. The increase is mainly due to one-time recommissioning costs in the United States of approximately $0.6 million, as well as higher repairs and maintenance expense on rigs and higher salary and related expenses. For the nine months ended September 30, 2018, cash operating expenses per Billable Day, excluding third party charges increased by 6% to $14,861, as compared to $14,068 in the same period of the prior year, mainly due to fixed operating costs being allocated over fewer Billable Days in 2018, as compared to 2017.

Gross Margin per Billable Day, excluding shortfall commitment revenue, improved for the three and nine months ended September 30, 2018 by 2% and 19% respectively, as compared to the same periods of the prior year, due to improving day rates.

Contract drilling Adjusted EBITDA for the three months ended September 30, 2018 increased by $0.9 million to $7.5 million, as compared to $6.6 million for the three months ended September 30, 2017. The increase is mainly due to higher day rates in Canada and increased activity in Canada and the United States. For the nine months ended September 30, 2018, Adjusted EBITDA decreased by $0.9 million to $22.8 million, as compared to $23.7 million for the nine months ended September 30, 2017. However, after normalizing for $6.4 million of shortfall commitment revenue recognized in the first quarter of 2017, Adjusted EBITDA for the nine months ended September 30, 2018 increased by $5.5 million (or 32%), compared to the same period of the prior year. On a normalized basis, the increase in 2018 is mainly due to increased pricing in both Canada and the United States and higher activity in the United States, partially offset by lower activity in Canada.

For the three and nine months ended September 30, 2018, cash administrative expenses, which exclude depreciation and stock based compensation, totalled $2.2 million and $7.0 million, and were 19% and 17% lower respectively, than the same periods of the prior year, mainly due to lower employee related costs.

Depreciation expense for the three and nine months ended September 30, 2018 of $13.2 million and $39.6 million, reflects increases of $0.2 million and $0.5 million respectively, over the same periods of the prior year, mainly due to capital assets added during the period.

Capital expenditures in the contract drilling segment totalled $3.4 million and $12.1 million for the three and nine months ended September 30, 2018 respectively. Capital expenditures in the third quarter of 2018 include $1.4 million of expansion capital and $2.0 million of maintenance capital, whereas capital expenditures for the nine months ended September 30, 2018 include $6.6 million of expansion capital and $5.5 million of maintenance capital. Contract drilling capital expenditures for the three and nine months ended September 30, 2018 represent a decrease of $2.2 million and an increase of $1.6 million respectively, from the $5.6 million and $10.5 million incurred in the respective periods in 2017. The Company incurred expansion capital relating to rig upgrades in 2018, as well as required maintenance capital.

Canadian Operations

While Canadian crude oil differentials have increased, absolute prices for Canadian crude oil have improved. As such, during the third quarter of 2018, Operating Days increased by 3% and Drilling Rig Utilization in Canada improved to 38% as compared to 36% in the same period of the prior year. The increase in activity is attributable to improved demand for Western’s Cardium and Duvernay class rigs, in addition to Western’s already well utilized Montney class rigs. On a year to date basis, Drilling Rig Utilization in Canada decreased to 35% in 2018 as compared to 36% in the same period of the prior year. The decrease in activity in Canada for the nine months ended September 30, 2018 is due to some of Western’s customers deferring their drilling plans amid high differentials on Canadian crude oil and low natural gas prices. In addition, wet weather in the latter part of the third quarter of 2018 negatively impacted activity for both the three and nine months ended September 30, 2018.

Drilling Rig Utilization in Canada of 38% in the third quarter of 2018 reflects an 800 bps premium to the CAODC average of 30%, as compared to a 700 bps premium to the CAODC average of 29% in the third quarter of 2017. The increase in the Company's premium to the CAODC average in the three months ended September 30, 2018 is due to improved activity, particularly for the Company's Duvernay and Cardium class rigs. Drilling Rig Utilization in Canada of 35% for the nine months ended September 30, 2018 reflects a 600 bps premium to the CAODC average of 29%, as compared to a 700 bps premium in the same period of the prior year. The decrease in the Company's premium for the nine months ended September 30, 2018 is a function of a smaller industry rig fleet, as rigs continue to be decommissioned or moved 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, decreased to 10.3% in the third quarter of 2018, as compared to 11.2% in the third quarter of 2017 and 9.9% for the nine months ended September 30, 2018, as compared to 10.4% in the same period of the prior year.

For the quarter ended September 30, 2018, Operating Revenue per Billable Day in Canada improved by 7% and totalled $17,961, compared to $16,825 in the same period of the prior year. For the nine months ended September 30, 2018, Operating Revenue per Billable Day in Canada improved by 9% and totalled $18,704, compared to $17,109 in the nine months ended September 30, 2017. The increase in pricing for both the three and nine months ended September 30, 2018 is due to the Company steadily raising rates over the last twelve months, as the energy industry continues to recover from a multiyear downturn.

United States Operations

In the Williston basin in North Dakota, where the Company operates, active drilling rigs in the industry remained relatively constant at 53 rigs at September 30, 2018, as compared to 50 rigs at September 30, 2017 per Baker Hughes. Improved WTI prices led to five of the Company's six drilling rigs operating during the three and nine months ended September 30, 2018. This led to Western's Operating Days in the United States, in the third quarter of 2018, increasing by 6 days (or 2%) which resulted in Drilling Rig Utilization of 50%, compared to 59% in the same period of the prior year. For the nine months ended September 30, 2018, Western's Operating Days in the United States increased by 62 days (or 9%), resulting in Drilling Rig Utilization of 44% compared to 48% in the same period of the prior year. For both the three and nine months ended September 30, 2018, five of the Company's six drilling rigs operated during the period. The decrease in Drilling Rig Utilization for both the three and nine months ended September 30, 2018 is mainly due an increased rig fleet as one Cardium class drilling rig from the Canadian fleet was transferred to the United States in late 2017. Operating Revenue per Billable Day was relatively consistent in the third quarter of 2018 totalling US$19,634 as compared to US$19,801 in the third quarter of 2017. The slightly lower day rate for the three months ended September 30, 2018 is mainly due to day rate increases on contracted rigs being offset by changes in the average rig mix. For the nine months ended September 30, 2018, Operating Revenue per Billable Day increased by 4% to US$20,493, as compared to US$19,763 in the same period of the prior year, as the Company has been able to raise day rates as commodity prices improve in the United States.

Production Services						
Financial Highlights	**Three months ended September 30**			**Nine months ended September 30**		
(stated in thousands)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Revenue						
Operating Revenue[1]	12,100	12,411	(3%)	37,062	39,094	(5%)
Third party charges	534	546	(2%)	1,672	2,241	(25%)
Total revenue	12,634	12,957	(2%)	38,734	41,335	(6%)
Expenses						
Operating						
Cash operating expenses	10,350	9,992	4%	30,651	31,034	(1%)
Depreciation	3,080	3,280	(6%)	9,523	10,075	(5%)
Stock based compensation	(18)	6	(400%)	43	114	(62%)
Total operating expenses	13,412	13,278	1%	40,217	41,223	(2%)
Administrative						
Cash administrative expenses	1,334	1,478	(10%)	3,958	4,569	(13%)
Depreciation	73	76	(4%)	243	237	3%
Stock based compensation	5	18	(72%)	20	79	(75%)
Total administrative expenses	1,412	1,572	(10%)	4,221	4,885	(14%)
Gross Margin[1]	2,284	2,965	(23%)	8,083	10,301	(22%)
Gross margin as a percentage of Operating Revenue	19%	24%	(21%)	22%	26%	(15%)
Adjusted EBITDA[1]	950	1,487	(36%)	4,125	5,732	(28%)
Adjusted EBITDA as a percentage of Operating Revenue	8%	12%	(33%)	11%	15%	(27%)
Operating Loss[1]	(2,203)	(1,869)	18%	(5,641)	(4,580)	23%
Capital expenditures	392	719	(45%)	1,779	1,675	6%

Operating Highlights						
Well servicing rig fleet:						
Average active rig count[1]	16.3	17.7	(8%)	15.8	17.3	(9%)
End of period	66	66	-	66	66	-
Service rig Operating Revenue per Service Hour[1]	653	629	4%	690	661	4%
Service Hours[1]	15,026	16,328	(8%)	43,090	47,296	(9%)
Service rig utilization [1]	25%	27%	(7%)	24%	26%	(8%)

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

The Company's production services segment includes Eagle's well servicing fleet, which totals 66 rigs, as well as Aero's oilfield rental equipment. Operating Revenue for the quarter ended September 30, 2018 decreased by $0.3 million (or 3%) to $12.1 million, compared to $12.4 million in the same period of the prior year. In the third quarter of 2018, Eagle's contribution to Operating Revenue in the production services segment decreased by 5% to $9.8 million compared to $10.3 million in the prior year, whereas Aero's contribution to Operating Revenue in the production services segment improved by 10% to $2.3 million in the third quarter of 2018 compared to $2.1 million in the same period of the prior year.

Operating Revenue in the production services segment for the nine months ended September 30, 2018, decreased by $2.0 million (or 5%) to $37.1 million, compared to $39.1 million in the same period of the prior year. For the nine months ended September 30, 2018, Eagle's contribution to Operating Revenue in the production services segment of $29.7 million compared to $31.3 million in the prior year, whereas Aero's contribution to Operating Revenue in the production services segment of $7.3 million compared to $7.8 million in the prior year. The decrease in Operating Revenue for Eagle for both the three and nine months ended September 30, 2018, as compared to the same periods in the prior year, is due to reduced activity offset partially by improved hourly rates. Aero's Operating Revenue improved for the three months ended September 30, 2018 due to improved pricing and demand for equipment, while Operating Revenue decreased during the nine months ended September 30, 2018 due to weaker demand in the first quarter of 2018.

Eagle's Service Hours decreased by 8% to 15,026 hours (25% utilization) in the third quarter of 2018, as compared to 16,328 hours (27% utilization) in the same period of the prior year, while Service Hours for the nine months ended September 30, 2018 decreased by 9% to 43,090 hours (24% utilization) as compared to 47,296 hours (26% utilization) in the same period of the prior year. The decrease in Service Hours for both the three and nine month periods ended September 30, 2018 is mainly due to lower activity resulting from customers deferring work amid widening crude oil differentials, lack of available crews, and wet weather in the latter part of the third quarter of 2018. Operating Revenue per Service Hour increased by 4% to $653 and $690 for the three and nine months ended September 30, 2018 respectively, as compared to the same periods in the prior year, due to the Company actively increasing hourly rates and changes in the average rig mix.

Adjusted EBITDA decreased in the third quarter of 2018 by $0.5 million (or 36%) to $1.0 million, compared to a $1.5 million in the same period of the prior year. For the nine months ended September 30, 2018, Adjusted EBITDA decreased by $1.6 million (or 28%), compared to $5.7 million in the prior year. The lower Adjusted EBITDA for the three and nine months ended September 30, 2018 was mainly due to lower demand for the Company's service rigs, offset partially by improved hourly rates.

During the three and nine months ended September 30, 2018, cash administrative expenses, which exclude depreciation and stock based compensation, totalled $1.3 million and $4.0 million respectively, and were 10% and 13% lower than the same periods in the prior year, mainly due to lower employee related costs.

Depreciation expense for the three and nine months ended September 30, 2018 decreased by 6% and 5% in each period to $3.2 million and $9.8 million respectively, as compared to $3.4 million and $10.3 million in the same periods of the prior year, due to certain capital assets being fully depreciated in the period.

During the three months ended September 30, 2018, capital expenditures in the production services segment totalled $0.4 million, as compared to $0.7 million for the three months ended September 30, 2017, and included expansion capital of $0.2 million, mainly related to additional oilfield rental equipment, and maintenance capital of $0.2 million. During the nine months ended September 30, 2018, capital expenditures in the production services segment totalled $1.8 million, as compared to $1.7 million for the nine months ended September 30, 2017, and included expansion capital of $0.7 million, mainly related to additional oilfield rental equipment, and maintenance capital of $1.1 million.

Corporate

	Three months ended September 30			Nine months ended September 30		
(stated in thousands)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Administrative						
Cash administrative expenses	783	1,189	(34%)	3,250	3,812	(15%)
Depreciation	136	163	(17%)	399	496	(20%)
Stock based compensation	150	111	35%	576	1,079	(47%)
Total administrative expenses	1,069	1,463	(27%)	4,225	5,387	(22%)
Finance costs	4,574	5,521	(17%)	14,447	16,352	(12%)
Other items	99	235	(58%)	2	2,056	(100%)
Income taxes						
Current tax (recovery) expense	-	33	(100%)	(45)	33	(236%)
Deferred tax recovery	(3,598)	(4,104)	(12%)	(9,948)	(11,746)	(15%)
Total income taxes	(3,598)	(4,071)	(12%)	(9,993)	(11,713)	(15%)
Operating Loss(1)	(919)	(1,352)	(32%)	(3,649)	(4,308)	(15%)

(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 nine months ended September 30, 2018 decreased by 34% and 15% respectively, as compared to the same periods in the prior year and totalled $0.8 million and $3.3 million respectively. The decrease for both the three and nine months ended September 30, 2018 is mainly due to lower employee related costs.

Finance costs for the three and nine months ended September 30, 2018, were lower than the same periods of the prior year, due to the decreased total debt level and lower interest rate on the Second Lien Facility, as compared to the previously outstanding Senior Notes. The Company refinanced its $265.0 million 7⅞% Senior Notes on February 1, 2018 with a combination of cash on hand, available Credit Facilities and the proceeds from the $215.0 million 7.25% Second Lien Facility draw. The Second Lien Facility was drawn on January 31, 2018 and currently has a principal balance outstanding of $213.9 million. The Company had an effective interest rate on its borrowings of 8.1% and 8.6% respectively, for the three and nine months ended September 30 2018, as compared to 8.3% throughout 2017. The increase in the effective interest rate for the nine months ended September 30, 2018 is due to $0.6 million in non-cash accretion expense related to the early redemption of the Senior Notes on February 1, 2018. On a cash basis, the Company had an effective interest rate on its borrowings of 7.7% throughout 2018, as compared to 8.0% throughout 2017.

Other items for the three months ended September 30, 2018 total a loss of $0.1 million, as compared to a loss of $0.2 million in the same period of the prior year, and include gains and losses on foreign exchange and asset sales. For the nine months ended September 30, 2018, other items total a negligible loss as compared to a loss of $2.1 million in the same period of the prior year. The first quarter of 2017 included $1.6 million of transaction costs related to an unsuccessful transaction.

For the third quarter of 2018, income taxes on a consolidated basis totalled a recovery of $3.6 million, representing an effective tax rate of 26.2%, as compared to an effective tax rate of 26.2% in the third quarter of 2017. For the nine month period ended September 30, 2018, income taxes on a consolidated basis totalled a recovery of $10.0 million, representing an effective tax rate of 24.1%, as compared to an effective tax rate of 26.5% in the same period of 2017.

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 September 30, 2018, Western had working capital of $18.7 million, a decrease of $44.2 million from December 31, 2017. Western's consolidated debt balance at September 30, 2018 decreased by $38.2 million (or 14%) to $228.1 million, as compared to $266.3 million at December 31, 2017.

During the nine months ended September 30, 2018, Western had the following changes to its cash balances, which resulted in a $44.0 million decrease in cash and cash equivalents in the period:

(stated in thousands)	
Opening balance, at December 31, 2017	48,825
Add:	
Issuance of Second Lien Facility	215,000
Adjusted EBITDA	23,700
Draw on Credit Facilities	12,009
Change in non cash working capital	2,878
Proceeds on sale of property and equipment	483
Deduct:	
Repayment of Senior Notes	(265,000)
Finance costs paid	(17,967)
Additions to property and equipment	(13,858)
Repayment of Second Lien Facility	(538)
Repayment of other long term debt	(463)
Other items	(291)
Ending balance, at September 30, 2018	**4,778**

During the first quarter of 2018, the $265.0 million 7⅞% Senior Notes were repaid at par on February 1, 2018 by a combination of a single draw on the Company's $215.0 million 7.25% Second Lien Facility, as well as through cash on hand and the funds available under the Company's Credit Facilities. This refinancing lowered Western's total debt and leverage metrics, decreased Western's cash interest expense on a go forward basis and extended the maturity on all of Western's long term debt. Additionally, Western will save approximately $5.3 million annually in cash interest expense, due to the decreased total debt level and lower interest rate on the Second Lien Facility, as compared to the Senior Notes.

Western's Credit Facilities, which have a limit of $80.0 million, mature on December 17, 2020. Western's cash from operations and available Credit Facilities are expected to be sufficient to cover Western's financial obligations, including the 2018 capital budget. Advances under the Credit Facilities are limited by the Company's borrowing base. The borrowing base is applicable when the Debt Service Coverage ratio is less than 2.0 and 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 $400.0 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 $50.0 million.

As at September 30, 2018, 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 $400.0 million.

Amounts borrowed under the Credit Facilities bear interest at the bank's Canadian prime rate, US base rate, LIBOR 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.

The Credit Facilities are secured by the assets of Western and its subsidiaries. A summary of the Company's financial covenants as at September 30, 2018 is as follows:

September 30, 2018	Covenants
Maximum Consolidated Senior Debt to Consolidated EBITDA Ratio (1)	3.0:1.0 or less
Maximum Consolidated Debt to Consolidated Capitalization Ratio (1)	0.6:1.0 or less
Minimum Debt Service Coverage Ratio (1)(2)	Not applicable

(1) See covenant definitions in Note 8 of the condensed consolidated financial statements as at and for the three and nine months ended September 30, 2018.

(2) Consolidated Debt Service Coverage Ratio is only applicable when $40.0 million or more is drawn on the Credit Facilities or the net book value of Western's property and equipment is less than $400.0 million. When applicable the ratio must meet or exceed 1.5 as at September 30, 2018 and December 31, 2018 and 2.0 thereafter.

At September 30, 2018, Western is in compliance with all debt covenants under its Credit Facilities.

For the three and nine months ended September 30, 2018, the Company had no significant customers comprising 10.0% or more of the Company's total revenue.

For the three months ended September 30, 2017, the Company had one significant customer comprising 10.5% of the Company's total revenue. For the nine months ended September 30, 2017, the Company had no 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 in 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)	Sep 30, 2018	Jun 30, 2018	Mar 31, 2018	Dec 31, 2017	Sep 30, 2017	Jun 30, 2017	Mar 31, 2017	Dec 31, 2016
Revenue	58,879	33,141	81,257	66,515	54,131	33,307	84,222	45,126
Operating Revenue(1)	54,071	30,976	72,965	59,255	51,111	30,469	78,153	41,649
Gross Margin(1)	12,025	5,562	20,271	15,886	12,299	5,667	24,458	8,507
Adjusted EBITDA(1)	7,691	897	15,112	10,067	6,882	121	18,625	3,506
Cash flow from operating activities	(1,968)	26,313	3,864	(800)	1,609	20,659	3,173	(1,327)
Net loss	(10,108)	(15,475)	(5,947)	(4,974)	(11,478)	(16,628)	(4,365)	(14,509)
per share - basic	(0.11)	(0.17)	(0.06)	(0.06)	(0.16)	(0.23)	(0.06)	(0.20)
per share - diluted	(0.11)	(0.17)	(0.06)	(0.06)	(0.16)	(0.23)	(0.06)	(0.20)
Total assets	669,079	670,584	706,895	760,504	737,385	758,278	785,040	793,525
Long term debt	222,564	210,944	227,401	265,219	264,958	264,702	264,150	264,070

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

Revenue and Adjusted EBITDA were impacted by lower commodity prices throughout the last eight quarters with the most significant declines occurring during 2016, with Revenue and Adjusted EBITDA beginning to recover in 2017. In 2017 and for each quarter in 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.

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.

Contractual Obligations

In the normal course of business the Company incurs contractual obligations. The expected maturities of the Company's contractual obligations as at September 30, 2018 are as follows:

(stated in thousands)	2018	2019	2020	2021	2022	Thereafter	Total
Second Lien Facility	538	2,150	2,150	2,150	2,150	205,324	214,462
Second Lien Facility interest	-	15,503	15,390	15,192	15,036	8,744	69,865
Trade payables and other current liabilities (1)	23,928	-	-	-	-	-	23,928
Operating leases	1,052	4,007	3,739	2,857	2,534	5,149	19,338
Revolving Facility	-	-	9,000	-	-	-	9,000
Purchase commitments	3,666	53	-	-	-	-	3,719
Operating Facility	-	-	3,009	-	-	-	3,009
Other long term debt	149	530	715	329	-	-	1,723
Total	29,333	22,243	34,003	20,528	19,720	219,217	345,044

(1) Trade payables and other current liabilities exclude the Company's interest accrued as at September 30, 2018 on the Second Lien Facility.

There have been no material changes in the contractual obligations, other than in the normal course of business, subsequent to September 30, 2018.

Outstanding Share Data

	October 24, 2018	September 30, 2018	December 31, 2017
Common shares outstanding	92,304,876	92,304,538	92,175,598
Warrants	7,099,546	7,099,546	7,099,546
Stock options outstanding	8,448,914	8,453,364	6,475,613
Restricted share units outstanding - equity settled	544,663	545,001	191,420

Off Balance Sheet Arrangements

As at September 30, 2018, Western had no off balance sheet arrangements in place.

Transactions with Related Parties

During the three and nine months ended September 30, 2018 and 2017, 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. Transaction costs related to undrawn term loans are recognized in deferred charges until the term loan is drawn. Subsequent to drawing on the term loan, transaction costs are netted against the term loan and amortized using the effective interest method.

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, per 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 September 30, 2018 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 September 30, 2018, 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.

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 nine months ended September 30, 2018, 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:

Business Combinations

The Company assesses the fair value of the net assets acquired in a business combination based on management's best estimate of market value, which takes into consideration the condition of the assets acquired, current industry conditions and the discounted future cash flows expected to be received from the assets as well as the amount it is expected to cost to settle the outstanding liabilities.

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. 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. Value-in-use and fair value less cost to sell calculations performed in assessing the recoverable amounts incorporate a number of key estimates. As at September 30, 2018, the Company completed its assessment of impairment and determined there was no impairment of property and equipment. Additionally, there were no reversals of previous property and equipment impairment losses during the three and nine months ended September 30, 2018.

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 (g) of the December 31, 2017 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 life 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 for the year ended December 31, 2017 as filed on SEDAR at www.sedar.com. The Company's primary business risks as at September 30, 2018 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 continue to 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. On November 22, 2015, the Alberta Government announced new emissions regulations, including a province wide price on carbon emissions effective January 1, 2017 and mandated methane emission reductions. Effective January 1, 2018 the Alberta government increased the price on carbon emissions to $30 per tonne, from $20 per tonne in 2017. In September 2016, the Canadian Federal Government announced its intention to impose a national carbon price on the provinces, requiring provinces to adopt either a carbon price or cap-and-trade approach and to meet a federally established minimum price starting at $10 per tonne in 2018 and rising by $10 per year to $50 per tonne in 2022. 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.
- 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 in addition to revenue, 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.

Gross Margin

Management believes that in addition to net income, 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 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 September 30		**Nine months ended September 30**	
(stated in thousands)	**2018**	**2017**	**2018**	**2017**
Operating Revenue				
Drilling	42,045	38,711	121,186	120,754
Production services	12,100	12,411	37,062	39,094
Less: inter-company eliminations	(74)	(11)	(236)	(115)
	54,071	**51,111**	**158,012**	**159,733**
Third party charges	4,808	3,020	15,265	11,927
Revenue	**58,879**	**54,131**	**173,277**	**171,660**
Less: operating expenses	(63,137)	(58,049)	(184,703)	(178,419)
Add:				
Depreciation - operating	16,232	16,196	48,936	48,989
Stock based compensation - operating	51	21	348	194
Gross Margin	**12,025**	**12,299**	**37,858**	**42,424**

Adjusted EBITDA

Management believes that in addition to net income, 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.

Operating Earnings (Loss)

Management believes that in addition to net income, 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 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 September 30		**Nine months ended September 30**	
(stated in thousands)	**2018**	**2017**	**2018**	**2017**
Net loss	**(10,108)**	**(11,478)**	**(31,530)**	**(32,471)**
Add:				
Finance costs	4,574	5,521	14,447	16,352
Income tax recovery	(3,598)	(4,071)	(9,993)	(11,713)
Depreciation - operating	16,232	16,196	48,936	48,989
Depreciation - administrative	269	300	814	929
EBITDA	**7,369**	**6,468**	**22,674**	**22,086**
Add:				
Stock based compensation - operating	51	21	348	194
Stock based compensation - administrative	172	158	676	1,292
Other items	99	235	2	2,056
Adjusted EBITDA	**7,691**	**6,882**	**23,700**	**25,628**
Subtract:				
Depreciation - operating	(16,232)	(16,196)	(48,936)	(48,989)
Depreciation - administrative	(269)	(300)	(814)	(929)
Operating Loss	**(8,810)**	**(9,614)**	**(26,050)**	**(24,290)**

Net Debt

The following table provides a reconciliation of long term debt under IFRS, as disclosed in the condensed consolidated balance sheets to Net Debt:

(stated in thousands)	**September 30, 2018**	**December 31, 2017**
Long term debt	222,564	265,219
Current portion of long term debt	1,755	475
Less: cash and cash equivalents	(4,778)	(48,825)
Net Debt	**219,541**	**216,869**

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”);
- Natural Gas Liquids (“NGL”);
- 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”, “propose”, “anticipate”, “believe”, “estimate”, “plan”, “predict”, “potential”, “continue”, “working 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 Operating Days typically generated from the Company’s contracts); the Company’s expansion and maintenance capital plans for 2018; the Company’s liquidity needs including the ability of current capital resources to cover Western’s financial obligations and the 2018 capital budget; the use and availability 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 proposed liquefied natural gas expansion in British Columbia; the potential impact of changes to environmental laws and regulations and the implementation of a price on carbon emissions in Alberta; the expectation of continued investment in the Canadian crude oil and natural gas industry; expectations relating to producer spending and activity levels for oilfield services, and 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” 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; crude oil transport and pipeline approval and development; the Company’s ability to finance its operations; 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; 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 included in Western's annual information form 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 Annual Information Form containing additional information relating to the Company is filed on SEDAR at www.sedar.com.