Second Quarter 2018 Interim Report — Date: July 25, 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 six months ended June 30, 2018 and 2017. This Management Discussion and Analysis ("MD&A") is dated July 25, 2018. All amounts are denominated in Canadian dollars (CDN$) unless otherwise identified.

Financial Highlights	**Three months ended June 30**			**Six months ended June 30**		
(stated in thousands, except share and per share amounts)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Revenue	33,141	33,307	-	114,398	117,529	(3%)
Operating Revenue(1)	30,976	30,469	2%	103,941	108,622	(4%)
Gross Margin(1)	5,562	5,667	(2%)	25,833	30,125	(14%)
Gross Margin as a percentage of Operating Revenue	18%	19%	(5%)	25%	28%	(11%)
Adjusted EBITDA(1)	897	121	641%	16,009	18,746	(15%)
Adjusted EBITDA as a percentage of Operating Revenue	3%	-	100%	15%	17%	(12%)
Cash flow from operating activities	26,313	20,659	27%	30,177	23,832	27%
Capital expenditures	5,426	3,435	58%	10,082	5,871	72%
Net loss	(15,475)	(16,628)	(7%)	(21,422)	(20,993)	2%
-basic net loss per share	(0.17)	(0.23)	(26%)	(0.23)	(0.28)	(18%)
-diluted net loss per share	(0.17)	(0.23)	(26%)	(0.23)	(0.28)	(18%)
Weighted average number of shares						
-basic	92,178,383	73,797,866	25%	92,177,719	73,796,911	25%
-diluted	92,178,383	73,797,866	25%	92,177,719	73,796,911	25%
Outstanding common shares as at period end	92,179,281	73,798,126	25%	92,179,281	73,798,126	25%
Operating Highlights(1)						
Contract Drilling						
Canadian Operations						
Average active rig count	9.2	10.3	(11%)	19.1	20.3	(6%)
Operating Revenue per Billable Day	19,453	17,411	12%	19,113	17,252 (3)	11%
Operating Revenue per Operating Day	21,363	19,009	12%	21,218	18,992 (3)	12%
Drilling rig utilization - Billable Days	18%	20%	(10%)	38%	40%	(5%)
Drilling rig utilization - Operating Days	17%	19%	(11%)	34%	36%	(6%)
CAODC industry average utilization - Operating Days(2)	17%	18%	(6%)	29%	29%	-
United States Operations						
Average active rig count	2.1	2.7	(22%)	2.7	2.5	8%
Operating Revenue per Billable Day (US$)	22,815	19,545	17%	21,040	19,738	7%
Operating Revenue per Operating Day (US$)	25,865	23,235	11%	23,356	23,573	(1%)
Drilling rig utilization - Billable Days	34%	54%	(37%)	45%	51%	(12%)
Drilling rig utilization - Operating Days	30%	46%	(35%)	40%	42%	(5%)
Production Services						
Average active rig count	10.5	9.4	12%	15.5	17.1	(9%)
Service rig Operating Revenue per Service Hour	723	652	11%	710	678	5%
Service rig utilization	16%	14%	14%	23%	26%	(12%)

(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 six months ended June 30, 2017.

Financial Position at (stated in thousands)	June 30, 2018	December 31, 2017	June 30, 2017
Working capital	7,717	62,866	51,730
Property and equipment	634,812	652,828	677,465
Total assets	670,584	760,504	758,278
Long term debt	210,944	265,219	264,702

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 six months ended June 30, 2018 and 2017.

	Three months ended June 30			Six months ended June 30		
	2018	2017	Change	2018	2017	Change
Average crude oil and natural gas prices[1][2]						
Crude Oil						
West Texas Intermediate (US$/bbl)	67.97	48.11	41%	65.63	49.87	32%
Western Canadian Select (CDN$/bbl)	64.44	51.35	25%	55.99	50.85	10%
Natural Gas						
30 day Spot AECO (CDN$/mcf)	1.22	2.78	(56%)	1.63	2.74	(41%)
Average foreign exchange rates[2]						
US dollar to Canadian dollar	1.29	1.34	(4%)	1.28	1.33	(4%)

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

(2) Source: Bloomberg

West Texas Intermediate ("WTI") on average improved in the second quarter of 2018 as compared to the first quarter of 2018, increasing by 8%, and was 41% higher compared to the same period in the prior year. For Western's Canadian customers, the impact of the weaker US dollar when translating WTI into the Canadian dollar equivalent, resulted in a 36% increase for the three months ended June 30, 2018, as compared to the same period in the prior year. Canadian heavy crude pricing improved in the second quarter of 2018, as Western Canadian Select ("WCS") on average increased by 37% as compared to the first quarter of 2018, and increased by 25% as compared to the same period of the prior year. Natural gas prices declined in the second quarter of 2018, as the 30 day spot AECO price decreased by 56% over the same period of the prior year and decreased by 37% as compared to the first quarter of 2018. However, the prices for condensate and natural gas liquids ("NGL") in Canada improved in the second quarter of 2018, as compared to the same period in the prior year.

Improved market conditions in 2018 has 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 16% and 23% respectively, for the three and six months ended June 30, 2018 as compared to the same periods in the prior year. However in Canada, higher crude oil prices have been largely offset by 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 levels. The CAODC reported that for drilling in Canada, the total number of Operating Days in the Western Canadian Sedimentary Basin ("WCSB") decreased by approximately 7.0% and 3.6% respectively, for the three and six months ended June 30, 2018, as compared to the same periods in the prior year.

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

- Second quarter Operating Revenue improved by $0.5 million to $31.0 million in 2018 as compared to $30.5 million in 2017. In the contract drilling segment, Operating Revenue totalled $21.8 million in the second quarter of 2018, a decrease of $1.0 million (or 4%) as compared to $22.8 million in the second quarter of 2017, while in the production services segment, Operating Revenue totalled $9.2 million for the three months ended June 30, 2018, as compared to $7.7 million in the three months ended June 30, 2017, an increase of $1.5 million (or 20%). While activity was lower in the contract drilling segment, improved pricing in all divisions, as well as higher utilization in the production services segment impacted Operating Revenue as described below:
  - Drilling rig utilization – Operating Days ("Drilling Rig Utilization") in Canada averaged 17% in the second quarter of 2018 compared to an average of 19% in the second quarter of 2017, reflecting a 200 basis points ("bps") decrease. The decrease in activity is attributable to some of Western's customers deferring their drilling programs in the second quarter of 2018 to the latter half of 2018. Second quarter 2018 Drilling Rig Utilization of 17% was consistent with the CAODC industry average of 17%, whereas in the second quarter of 2017, Drilling Rig Utilization of 19% represented a premium of 100 bps to the industry average. The decrease in the Company's utilization premium to the industry average in the second quarter of 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 8.0% in the second quarter of 2018, as compared to 8.4% in the second quarter of 2017. While utilization decreased during the quarter, pricing continued to increase and resulted in a 12% improvement in Operating Revenue per Billable Day in the second 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, two of the Company's six drilling rigs operated throughout the quarter on long term contracts, resulting in Drilling Rig Utilization of 30% in the second quarter of 2018, as compared to 46% in the same period of the prior year. The decrease in Drilling Rig Utilization is mainly due to one rig being out of service during the second quarter of 2018 as upgrades were completed. This rig began work near the end of the second quarter of 2018 on a long term contract. Operating Revenue per Billable Day improved during the second quarter of 2018 by 17% as compared to the second quarter of 2017, mainly due to changes in the average rig mix, higher day rates and standby revenue earned during the quarter on a third drilling rig that began operating on a long term contract near the end of the second quarter; and
  - Well servicing utilization was 16% in the second quarter of 2018 compared to 14% in the same period of the prior year, due to increased demand in a number of areas where the Company operates. Hourly rates improved during the second quarter of 2018, increasing by 11% 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. Higher utilization and improved pricing, led to a $1.4 million (or 25%) increase in well servicing Operating Revenue in the period.
- Second quarter Adjusted EBITDA increased by $0.8 million (or 641%) to $0.9 million in the second quarter of 2018 as compared to $0.1 million in the second quarter of 2017. The year over year change in Adjusted EBITDA is due to improved pricing in all divisions, as well as higher well servicing activity, which was partially offset by lower Drilling Rig Utilization.
- Administrative expenses, excluding depreciation and stock based compensation, decreased by $0.8 million (or 15%) to $4.7 million, as compared to $5.5 million in the second quarter of 2017, mainly due to lower employee related costs.
- The Company incurred a net loss of $15.5 million in the second quarter of 2018 ($0.17 per basic common share) as compared to a net loss of $16.6 million in the same period in 2017 ($0.23 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 all divisions;
- A $0.2 million decrease in stock based compensation expense as fewer unvested stock options and equity settled restricted share units were outstanding in the quarter; and
- A $0.1 million positive change in other items, which include gains and losses on foreign exchange and asset sales.

Offsetting the above mentioned items was a $1.0 million decrease in income tax recovery due to improved earnings before taxes.

- Second quarter 2018 capital expenditures of $5.4 million included $3.8 million of expansion capital and $1.6 million of maintenance capital. In total, capital spending in the second quarter of 2018 increased by $2.0 million from the $3.4 million incurred in the second quarter of 2017. The Company incurred expansion capital mainly related to drilling rig upgrades, as well as required maintenance capital, in the second quarter of 2018.

Operational results for the six months ended June 30, 2018 include:

- Operating Revenue for the six month period ended June 30, 2018 decreased by $4.7 million (or 4%) to $103.9 million as compared to $108.6 million for the six month period ended June 30, 2017. However, after normalizing for $6.4 million of shortfall commitment revenue recognized in the first quarter of 2017, Operating Revenue for the six months ended June 30, 2018 improved by $1.7 million (or 2%). In the contract drilling segment, Operating Revenue totalled $79.1 million for the six months ended June 30, 2018, which after normalizing for $6.4 million of shortfall commitment revenue recognized in 2017, resulted in Operating Revenue improving by $3.5 million (or 5%). In the production services segment, Operating Revenue totalled $25.0 million for the six months ended June 30, 2018, as compared to $26.7 million in the same period of the prior year, a decrease of $1.7 million (or 6%). 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 six month period ended June 30, 2018 averaged 34%, compared to an average of 36% for the six month period ended June 30, 2017, reflecting a 200 bps decrease. The decrease in activity in the first half of 2018 is due to some of Western's customers ending their winter drilling programs early and deferring their drilling plans to later in 2018. Drilling Rig Utilization of 34% in 2018 represented a premium of 500 bps to the CAODC industry average of 29%, whereas in the first six months of 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 9.6% in the first half of 2018, as compared to 10.0% in the first half of 2017. While utilization decreased during the six months ended June 30, 2018, pricing continued to increase and resulted in an 11% 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 changes in the average rig mix and 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, four of the Company's six drilling rigs operated during the period, two of which were working throughout the period on long term contracts, resulting in Operating Days increasing by 15% for the six months ended June 30, 2018, as compared to the same period in the prior year. While activity increased, Drilling Rig Utilization decreased to 40% for the six months ended June 30, 2018, as compared to 42% in the same period of the prior year, due to an increased rig fleet as a 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 7% in the first six months of 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. Additionally, day rates were aided by standby revenue earned in the second quarter of 2018 on a third drilling rig that began operating on a long term contract near the end of the second quarter; and
  - Well servicing utilization of 23% for the six months ended June 30, 2018 compared to 26% in the same period of the prior year, due to customers deferring work amid widening crude oil differentials in the first quarter of 2018, as activity in the second quarter improved year over year. Hourly rates improved for the six months ended June 30, 2018, increasing by 5% 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 $1.1 million (or 5%) decrease in well servicing Operating Revenue in 2018.

- Adjusted EBITDA for the six months ended June 30, 2018 decreased by $2.7 million (or 15%) to $16.0 million as compared to $18.7 million for the six months ended June 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 $3.7 million (or 30%), as compared to the same period in the prior year. The year over year change in Adjusted EBITDA is due to improved pricing in all divisions and increased activity in the United States, offset by decreased activity in Canada and lower shortfall commitment revenue.
- Administrative expenses, excluding depreciation and stock based compensation, for the six month period ended June 30, 2018 decreased by $1.6 million (or 14%) to $9.8 million, as compared to $11.4 million in the same period of the prior year, mainly due to lower employee related costs.
- The Company incurred a net loss of $21.4 million for the six months ended June 30, 2018 ($0.23 per basic common share) as compared to a net loss of $21.0 million in the same period in 2017 ($0.28 per basic common share). The change can be attributed to the following:
    - A $2.7 million decrease in Adjusted EBITDA, mainly due to lower shortfall commitment revenue and decreased activity in Canada, partially offset by improved pricing in all divisions and increased activity in the United States; and
    - A $1.2 million decrease in income tax recovery due to improved earnings before taxes.

  Offsetting the above mentioned items was:
    - A $1.9 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 $0.9 decrease in finance costs, due to lower total debt levels; and
    - A $0.5 million decrease in stock based compensation expense as fewer unvested stock options and equity settled restricted share units were outstanding in the quarter.
- Year to date capital expenditures of $10.1 million included $5.6 million of expansion capital and $4.5 million of maintenance capital. In total, capital spending for the six months ended June 30, 2018 increased by $4.2 million from the $5.9 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, 20 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 in 2018. While Canadian crude oil prices are much improved, capital budgets for Western's Canadian customers have not increased materially. As such, year over year activity levels for the remainder of 2018 are expected to remain relatively consistent with 2017, with the potential to modestly improve if recent gains in crude oil pricing are maintained. Improving gross margin continues to be a priority for the Company and, as has been demonstrated over the last five 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 June 30, 2018, Western had nothing drawn on its $80.0 million Credit Facilities, which mature on December 17, 2020 and $215.0 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 potential 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 June 30**			**Six months ended June 30**		
(stated in thousands)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Revenue						
Operating Revenue[1]	21,791	22,807	(4%)	79,141	82,043	(4%)
Third party charges	1,730	2,413	(28%)	9,319	7,212	29%
Total revenue	23,521	25,220	(7%)	88,460	89,255	(1%)
Expenses						
Operating						
Cash operating expenses	19,431	20,782	(7%)	68,426	66,466	3%
Depreciation	13,149	13,027	1%	26,261	25,998	1%
Stock based compensation	132	29	355%	236	65	263%
Total operating expenses	32,712	33,838	(3%)	94,923	92,529	3%
Administrative						
Cash administrative expenses	2,311	2,826	(18%)	4,732	5,665	(16%)
Depreciation	57	65	(12%)	113	135	(16%)
Stock based compensation	37	46	(20%)	63	105	(40%)
Total administrative expenses	2,405	2,937	(18%)	4,908	5,905	(17%)
Gross Margin[1]	4,090	4,438	(8%)	20,034	22,789	(12%)
Gross Margin as a percentage of Operating Revenue	19%	19%	-	25%	28%	(11%)
Adjusted EBITDA[1]	1,779	1,612	10%	15,302	17,124	(11%)
Adjusted EBITDA as a percentage of Operating Revenue	8%	7%	14%	19%	21%	(10%)
Operating Loss[1]	(11,427)	(11,480)	-	(11,072)	(9,009)	23%
Capital expenditures	4,921	3,108	58%	8,695	4,913	77%

Operating Highlights						
Canadian Operations						
Contract drilling rig fleet:						
Average active rig count[1]	9.2	10.3	(11%)	19.1	20.3	(6%)
End of period	50	51	(2%)	50	51	(2%)
Operating Revenue per Billable Day[1]	19,453	17,411	12%	19,113	17,252 [3]	11%
Operating Revenue per Operating Day[1]	21,363	19,009	12%	21,218	18,992 [3]	12%
Operating Days[1]	761	859	(11%)	3,112	3,345	(7%)
Number of meters drilled	244,535	267,243	(8%)	918,741	936,535	(2%)
Number of wells drilled	59	56	6%	237	247	(4%)
Average Operating Days per well	12.8	15.3	(16%)	13.2	13.5	(2%)
Drilling rig utilization - Billable Days[1]	18%	20%	(10%)	38%	40%	(5%)
Drilling rig utilization - Operating Days[1]	17%	19%	(11%)	34%	36%	(6%)
CAODC industry average utilization - Operating Days[1][2]	17%	18%	(6%)	29%	29%	-
United States Operations						
Contract drilling rig fleet:						
Average active rig count[1]	2.1	2.7	(22%)	2.7	2.5	8%
End of period	6	5	20%	6	5	20%
Operating Revenue per Billable Day (US$)[1]	22,815	19,545	17%	21,040	19,738	7%
Operating Revenue per Operating Day (US$)[1]	25,865	23,235	11%	23,356	23,573	(1%)
Operating Days[1]	166	208	(20%)	440	384	15%
Number of meters drilled	57,659	62,596	(8%)	136,478	106,080	29%
Number of wells drilled	11	11	-	26	18	44%
Average Operating Days per well	15.1	19.8	(24%)	16.9	21.5	(21%)
Drilling rig utilization - Billable Days[1]	34%	54%	(37%)	45%	51%	(12%)
Drilling rig utilization - Operating Days[1]	30%	46%	(35%)	40%	42%	(5%)

(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 six months ended June 30, 2017.

For the three months ended June 30, 2018, Operating Revenue in the contract drilling segment totalled $21.8 million, a $1.0 million decrease (or 4%), as compared to the same period of the prior year, as decreased activity was partially offset by increased pricing in both Canada and the United States. For the six months ended June 30, 2018, Operating Revenue in the contract drilling segment totalled $79.1 million, a $2.9 million decrease (or 4%), 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 six months ended June 30, 2018 increased by $3.5 million (or 5%), as compared to the six months ended June 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 six months ended June 30, 2018, third party charges per Billable Day in the contract drilling segment increased to approximately $1,700 and $2,500 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 June 30, 2018, cash operating expenses per Billable Day in the contract drilling segment, excluding third party charges, increased by 12% to total approximately $17,295, as compared to approximately $15,511 in the same period of the prior year, mainly due to increased salaries expense, due to changes in crew configurations which are typically billed to the customer, and higher repairs and maintenance costs incurred, as well as fixed operating costs being allocated over fewer Billable Days in the second quarter of 2018, as compared to the same period in the prior year. For the six months ended June 30, 2018, cash operating expenses per Billable Day, excluding third party charges increased by 5% to total approximately $14,990, as compared to approximately $14,309 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 six months ended June 30, 2018 by 7% and 29% respectively, as compared to the same periods of the prior year, due to higher day rates in Canada and the United States.

Contract drilling Adjusted EBITDA for the three months ended June 30, 2018 increased by $0.2 million to $1.8 million, as compared to $1.6 million for the three months ended June 30, 2017. The increase is mainly due to higher day rates in Canada and the United States, which were partially offset by lower activity. For the six months ended June 30, 2018, Adjusted EBITDA decreased by $1.8 million to $15.3 million, as compared to $17.1 million for the six months ended June 30, 2017. However, after normalizing for $6.4 million of shortfall commitment revenue recognized in the first quarter of 2017, Adjusted EBITDA for the first half of 2018 increased by $4.6 million (or 43%), compared to the same period of the prior year. On a normalized basis, the increase in 2018 is mainly due to higher Operating Revenue per Billable Day and higher activity in the United States, partially offset by lower activity in Canada.

For the three and six months ended June 30, 2018, cash administrative expenses, which exclude depreciation and stock based compensation, totalled $2.3 million and $4.7 million, and were 18% and 16% lower respectively, than the same periods of the prior year, mainly due to lower employee related costs.

Depreciation expense for the three and six months ended June 30, 2018 of $13.2 million and $26.4 million, reflects increases of $0.1 million and $0.2 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 $4.9 million and $8.7 million for the three and six months ended June 30, 2018 respectively. Capital expenditures in the second quarter of 2018 include $3.5 million of expansion capital and $1.4 million of maintenance capital, whereas capital expenditures for the first half of 2018 include $5.2 million of expansion capital and $3.5 million of maintenance capital. Contract drilling capital expenditures for the three and six months ended June 30, 2018 represent increases of $1.8 million and $3.8 million respectively, from the $3.1 million and $4.9 million incurred in the respective periods in 2017. The Company incurred expansion capital relating to rig upgrades in the first half of 2018, as well as required maintenance capital.

Canadian Operations

During the second quarter of 2018, Operating Days decreased by 11% and Drilling Rig Utilization in Canada decreased to 17% as compared to 19% in the same period of the prior year. The decrease in activity is attributable to some of Western's customers deferring their drilling programs in the second quarter of 2018 to the latter half of 2018. On a year to date basis, Drilling Rig Utilization in Canada decreased to 34% in 2018 as compared to 36% in the same period of the prior year. The decrease in activity in Canada for the six months ended June 30, 2018 is due to some of Western's customers ending their winter drilling programs early in the first quarter of 2018 and deferring their drilling plans to later in 2018.

Drilling Rig Utilization in Canada of 17% in the second quarter of 2018 is consistent with the CAODC average of 17%, as compared to a 100 bps premium to the CAODC average of 18% in the second quarter of 2017. Drilling Rig Utilization in Canada of 34% for the six months ended June 30, 2018 reflects a 500 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 to the CAODC average in the three and six months ended June 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, remained relatively consistent at 8.0% in the second quarter of 2018, as compared to 8.4% in the second quarter of 2017 and 9.6% for the six months ended June 30, 2018, as compared to 10.0% in the same period of the prior year.

For the quarter ended June 30, 2018, Operating Revenue per Billable Day in Canada improved by 12% and totalled $19,453, compared to $17,411 in the same period of the prior year. The Company has been successful in steadily raising rates over the last twelve months as the energy industry continues to recover from a multi-year downturn. For the six months ended June 30, 2018, Operating Revenue per Billable Day in Canada improved by 11% and totalled $19,113, compared to $17,252 in the six months ended June 30, 2017. The increase in pricing for both the three and six months ended June 30, 2018 is due to changes in the average rig mix and the Company steadily raising rates over the last twelve months.

United States Operations

In the Williston basin in North Dakota, where the Company operates, active drilling rigs in the industry remained relatively constant at 54 rigs at June 30, 2018, as compared to 52 rigs at June 30, 2017 per Baker Hughes, a GE Company. Western's Operating Days in the United States decreased by 42 days (or 20%) resulting in Drilling Rig Utilization of 30% for the second quarter of 2018, compared to 46% in the same period of the prior year. The decrease in Drilling Rig Utilization is mainly due to one rig being out of service during the second quarter of 2018 as upgrades were completed. This rig began work near the end of the second quarter of 2018 on a long term contract. For the six months ended June 30, 2018, Western's Operating Days in the United States increased by 56 days (or 15%), resulting in Drilling Rig Utilization of 40% compared to 42% in the same period of the prior year. While Operating Days improved during the six months ended June 30, 2018 by 15%, Drilling Rig Utilization decreased due to an increased rig fleet as a Cardium class drilling rig from the Canadian fleet was transferred to the United States fleet in late 2017. Operating Revenue per Billable Day improved in the second quarter of 2018 to US$22,815 as compared to US$19,545 in the second quarter of 2017. Similarly, for the six months ended June 30, 2018, Operating Revenue per Billable Day improved by 7% to US$21,040, as compared to US$19,738 in the same period of the prior year. The higher day rates for both the three and six months ended June 30, 2018 are mainly due to changes in the average rig mix and standby revenue earned during the second quarter of 2018 on a third drilling rig that began operating on a long term contract near the end of the second quarter.

Production Services

Financial Highlights	**Three months ended June 30**			**Six months ended June 30**		
(stated in thousands)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Revenue						
Operating Revenue(1)	9,227	7,670	20%	24,962	26,683	(6%)
Third party charges	435	425	2%	1,138	1,695	(33%)
Total revenue	9,662	8,095	19%	26,100	28,378	(8%)
Expenses						
Operating						
Cash operating expenses	8,191	6,866	19%	20,301	21,042	(4%)
Depreciation	3,163	3,385	(7%)	6,443	6,795	(5%)
Stock based compensation	57	47	21%	61	108	(44%)
Total operating expenses	11,411	10,298	11%	26,805	27,945	(4%)
Administrative						
Cash administrative expenses	1,260	1,482	(15%)	2,624	3,091	(15%)
Depreciation	101	76	33%	170	161	6%
Stock based compensation	4	41	(90%)	15	61	(75%)
Total administrative expenses	1,365	1,599	(15%)	2,809	3,313	(15%)
Gross Margin(1)	1,471	1,229	20%	5,799	7,336	(21%)
Gross margin as a percentage of Operating Revenue	16%	16%	-	23%	27%	(15%)
Adjusted EBITDA(1)	211	(253)	(183%)	3,175	4,245	(25%)
Adjusted EBITDA as a percentage of Operating Revenue	2%	(3%)	(167%)	13%	16%	(19%)
Operating Loss(1)	(3,053)	(3,714)	(18%)	(3,438)	(2,711)	27%
Capital expenditures	505	325	55%	1,387	956	45%

Operating Highlights						
Well servicing rig fleet:						
Average active rig count(1)	10.5	9.4	12%	15.5	17.1	(9%)
End of period	66	66	-	66	66	-
Service rig Operating Revenue per Service Hour(1)	723	652	11%	710	678	5%
Service Hours(1)	9,588	8,511	13%	28,064	30,968	(9%)
Service rig utilization (1)	16%	14%	14%	23%	26%	(12%)

(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 June 30, 2018 improved by $1.5 million (or 20%) to $9.2 million, compared to $7.7 million in the same period of the prior year. In the second quarter of 2018, Eagle's contribution to Operating Revenue in the production services segment increased by 25% to $6.9 million compared to $5.5 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 second quarter of 2018 compared to $2.1 million in the same period of the prior year. Operating Revenue for the six months ended June 30, 2018, decreased by $1.7 million (or 6%) to $25.0 million, compared to $26.7 million in the same period of the prior year. For the six months ended June 30, 2018, Eagle's contribution to Operating Revenue in the production services segment of $19.9 million compared to $21.0 million in the prior year, whereas Aero's contribution to Operating Revenue in the production services segment of $5.0 million compared to $5.7 million in the prior year. The increase in Operating Revenue for Eagle for the three months ended June 30, 2018, as compared to the same period in the prior year, is due to improved hourly rates and activity during the quarter, while for the six months ended June 30, 2018, Operating Revenue decreased due to reduced customer demand in the first quarter of 2018 resulting from customers deferring work amid widening crude oil differentials. Similarly, Aero's Operating Revenue improved for the three months ended June 30, 2018 due to higher demand for equipment, while Operating Revenue decreased during the six months ended June 30, 2018 due to weaker demand in the first quarter of 2018.

Eagle's Service Hours increased by 13% to 9,588 hours (16% utilization) in the second quarter of 2018, as compared to 8,511 hours (14% utilization) in the same period of the prior year, while Service Hours for the first six months of 2018 decreased by 9% to 28,064 hours (23% utilization) as compared to 30,968 hours (26% utilization) in the same period of the prior year. The increase in Service Hours for the three month period ended June 30, 2018 is due to the higher demand in a number of areas where the Company operates. For the six month period ended June 30, 2018, activity was lower than the six months ended June 30, 2017 due to customers deferring work amid widening crude oil differentials in the first quarter of 2018. Operating Revenue per Service Hour increased by 11% to $723 and 5% to $710 for the three and six months ended June 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 improved in the second quarter of 2018 by $0.5 million (or 183%) to a gain of $0.2 million, compared to a loss of $0.3 million in the same period of the prior year. The higher Adjusted EBITDA in the second quarter of 2018 was due to improved pricing and higher demand for the Company's service rigs. For the six months ended June 30, 2018, Adjusted EBITDA decreased by $1.0 million (or 25%), compared to $4.2 million in the prior year. The lower Adjusted EBITDA in the six months ended June 30, 2018 was due to lower activity in the first quarter of 2018 as customers deferred work amid widening crude oil differentials and low natural gas prices.

During the three and six months ended June 30, 2018, cash administrative expenses, which exclude depreciation and stock based compensation, totalled $1.3 million and $2.6 million respectively, and were 15% lower than the same periods in the prior year, mainly due to lower employee related costs.

Depreciation expense for the three and six months ended June 30, 2018 decreased by 6% in each period to $3.3 million and $6.6 million respectively, as compared to $3.5 million and $7.0 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 June 30, 2018, capital expenditures in the production services segment totalled $0.5 million, as compared to $0.3 million for the three months ended June 30, 2017, and included expansion capital of $0.3 million and maintenance capital of $0.2 million. During the six months ended June 30, 2018, capital expenditures in the production services segment totalled $1.4 million, as compared to $1.0 million for the six months ended June 30, 2017, and included expansion capital of $0.5 million, mainly related to additional oilfield rental equipment, and maintenance capital of $0.9 million.

Corporate

	Three months ended June 30			Six months ended June 30		
(stated in thousands)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Administrative						
Cash administrative expenses	1,094	1,238	(12%)	2,467	2,623	(6%)
Depreciation	128	166	(23%)	263	333	(21%)
Stock based compensation	213	478	(55%)	426	968	(56%)
Total administrative expenses	1,435	1,882	(24%)	3,156	3,924	(20%)
Finance costs	4,493	5,419	(17%)	9,873	10,831	(9%)
Other items	(10)	124	(108%)	(97)	1,821	(105%)
Income taxes						
Current tax recovery	(45)	-	(100%)	(45)	-	(100%)
Deferred tax recovery	(5,108)	(6,154)	(17%)	(6,350)	(7,642)	(17%)
Total income taxes	(5,153)	(6,154)	(16%)	(6,395)	(7,642)	(16%)
Operating Loss(1)	(1,222)	(1,404)	(13%)	(2,730)	(2,956)	(8%)

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

Corporate cash administrative expenses, which exclude depreciation and stock based compensation, for the three and six months ended June 30, 2018 decreased by 12% and 6% respectively, as compared to the same periods in the prior year and totalled $1.1 million and $2.5 million respectively. The decrease for both the three and six months ended June 30, 2018 is mainly due to lower employee related costs.

Finance costs for the quarter ended June 30, 2018, were lower than the same period of the prior year, due to lower consolidated debt balances in 2018. Similarly, for the six months ended June 30, 2018, finance costs were lower than the same period in the prior year, as higher non-cash interest expense related to the Company's $265.0 million 7⅞% Senior Notes redemption on February 1, 2018 was offset by lower interest associated with the Company's $215.0 million 7.25% Second Lien Facility, which was drawn on January 31, 2018. The Company had an effective interest rate on its borrowings of 8.3% and 8.8% respectively, for the three and six months ended June 30 2018, as compared to 8.2% throughout the first six months of 2017. The increase in the effective interest rate for the six months ended June 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 the first six months of 2018, as compared to 8.0% throughout the first six months of 2017.

Other items for the three months ended June 30, 2018 total a negligible gain, as compared to a loss of $0.1 million in the same period of the prior year. For the six months ended June 30, 2018, other items total a gain of $0.1 million, as compared to a loss of $1.8 million in the same period of the prior year, and include gains and losses on foreign exchange and asset sales. The first quarter of 2017 included $1.6 million of transaction costs related to an unsuccessful transaction.

For the second quarter of 2018, income taxes on a consolidated basis totalled a recovery of $5.2 million, representing an effective tax rate of 25.0%, as compared to an effective tax rate of 27.0% in the second quarter of 2017. For the six month period ended June 30, 2018, income taxes on a consolidated basis totalled a recovery of $6.4 million, representing an effective tax rate of 23.0%, as compared to an effective tax rate of 26.7% 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 June 30, 2018, Western had working capital of $9.0 million, a decrease of $53.9 million from December 31, 2017. Western's consolidated Net Debt balance at June 30, 2018 was $206.7 million.

During the six months ended June 30, 2018, Western had the following changes to its cash balances, which resulted in a $42.8 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	16,009
Proceeds on sale of property and equipment	317
Deduct:	
Repayment of Senior Notes	(265,000)
Change in non cash working capital	12,597
Finance costs paid	(11,101)
Additions to property and equipment	(10,082)
Other items	(529)
Ending balance, at June 30, 2018	**6,036**

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. 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. Completing these financing transactions has 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.

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 June 30, 2018, the borrowing base calculation was not applicable as no amounts were 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 June 30, 2018 is as follows:

June 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 six months ended June 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 1.25 as at June 30, 2018, 1.5 as at September 30, 2018 and December 31, 2018 and 2.0 thereafter.

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

For the three months ended June 30, 2018, the Company had three significant customers comprising 14.9%, 12.2% and 10.3% respectively, of the Company's total revenue. The trade receivable balance outstanding related to these customers was 6.7%, 9.2% and 9.8% respectively, of the Company's total trade and other receivables at June 30, 2018. For the six months ended June 30, 2018, the Company had no customers comprising 10.0% or more of the Company's total revenue.

For the three months ended June 30, 2017, the Company had two significant customers comprising 15.9% and 11.4% of the Company's total revenue respectively. For the six months ended June 30, 2017, the Company had no customer's 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)	Jun 30, 2018	Mar 31, 2018	Dec 31, 2017	Sep 30, 2017	Jun 30, 2017	Mar 31, 2017	Dec 31, 2016	Sept 30, 2016
Revenue	33,141	81,257	66,515	54,131	33,307	84,222	45,126	32,485
Operating Revenue(1)	30,976	72,965	59,255	51,111	30,469	78,153	41,649	30,665
Gross Margin(1)	5,562	20,271	15,886	12,299	5,667	24,458	8,507	5,685
Adjusted EBITDA(1)	897	15,112	10,067	6,882	121	18,625	3,506	896
Cash flow from operating activities	26,313	3,864	(800)	1,609	20,659	3,173	(1,327)	909
Net loss	(15,475)	(5,947)	(4,974)	(11,478)	(16,628)	(4,365)	(14,509)	(16,973)
per share - basic	(0.17)	(0.06)	(0.06)	(0.16)	(0.23)	(0.06)	(0.20)	(0.23)
per share - diluted	(0.17)	(0.06)	(0.06)	(0.16)	(0.23)	(0.06)	(0.20)	(0.23)
Total assets	670,584	706,895	760,504	737,385	758,278	785,040	793,525	794,170
Long term debt	210,944	227,401	265,219	264,958	264,702	264,150	264,070	264,118

(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 the first half of 2018, after normalizing for shortfall commitment revenue, Revenue and Adjusted EBITDA in each quarter increased, as compared to the same quarter in the prior year, due to improving market conditions.

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 June 30, 2018 are as follows:

(stated in thousands)	2018	2019	2020	2021	2022	Thereafter	Total
Second Lien Facility	1,075	2,150	2,150	2,150	2,150	205,325	215,000
Second Lien Facility interest	6,449	15,503	15,390	15,192	15,036	8,744	76,314
Trade payables and other current liabilities (1)	19,107	-	-	-	-	-	19,107
Operating leases	2,087	3,894	3,641	2,757	2,436	5,075	19,890
Purchase commitments	2,756	-	-	-	-	-	2,756
Other long term debt	329	515	699	301	-	-	1,844
Total	31,803	22,062	21,880	20,400	19,622	219,144	334,911

(1) Trade payables and other current liabilities exclude the Company's interest accrued as at June 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 June 30, 2018.

Outstanding Share Data

	July 25, 2018	June 30, 2018	December 31, 2017
Common shares outstanding	92,180,310	92,179,281	92,175,598
Warrants	7,099,546	7,099,546	7,099,546
Stock options outstanding	5,736,401	5,680,121	6,475,613
Restricted share units outstanding - equity settled	192,708	187,737	191,420

Off Balance Sheet Arrangements

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

Transactions with Related Parties

During the three and six months ended June 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 June 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 June 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 six months ended June 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 June 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 six months ended June 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 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 accounts receivable 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 June 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 re-finance 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 June 30		**Six months ended June 30**	
(stated in thousands)	**2018**	**2017**	**2018**	**2017**
Operating Revenue				
Drilling	21,791	22,807	79,141	82,043
Production services	9,227	7,670	24,962	26,683
Less: inter-company eliminations	(42)	(8)	(162)	(104)
	30,976	**30,469**	**103,941**	**108,622**
Third party charges	2,165	2,838	10,457	8,907
Revenue	**33,141**	**33,307**	**114,398**	**117,529**
Less: operating expenses	(44,081)	(44,128)	(121,566)	(120,370)
Add:				
Depreciation - operating	16,313	16,412	32,704	32,793
Stock based compensation - operating	189	76	297	173
Gross Margin	**5,562**	**5,667**	**25,833**	**30,125**

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 June 30		**Six months ended June 30**	
(stated in thousands)	**2018**	**2017**	**2018**	**2017**
Net loss	**(15,475)**	**(16,628)**	**(21,422)**	**(20,993)**
Add:				
Finance costs	4,493	5,419	9,873	10,831
Income tax recovery	(5,153)	(6,154)	(6,395)	(7,642)
Depreciation - operating	16,313	16,412	32,704	32,793
Depreciation - administrative	286	307	545	629
EBITDA	**464**	**(644)**	**15,305**	**15,618**
Add:				
Stock based compensation - operating	189	76	297	173
Stock based compensation - administrative	254	565	504	1,134
Other items	(10)	124	(97)	1,821
Adjusted EBITDA	**897**	**121**	**16,009**	**18,746**
Subtract:				
Depreciation - operating	(16,313)	(16,412)	(32,704)	(32,793)
Depreciation - administrative	(286)	(307)	(545)	(629)
Operating Loss	**(15,702)**	**(16,598)**	**(17,240)**	**(14,676)**

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)	**June 30, 2018**	**December 31, 2017**
Long term debt	210,944	265,219
Current portion of long term debt	1,789	475
Less: cash and cash equivalents	(6,036)	(48,825)
Net Debt	**206,697**	**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.

<u>Contract Drilling Rig Classifications:</u>

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 the words "may", "will", "should", "could", "expect", "intend", "anticipate", "believe", "estimate", "plan", "predict", "potential", "continue", 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; 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.