2018 Management Discussion & Analysis

Date: February 13, 2019

The following discussion of the financial condition, changes in financial condition and results of operations of Western Energy Services Corp. (the "Company" or "Western") should be read in conjunction with the audited consolidated financial statements and accompanying notes of the Company for the years ended December 31, 2018 and 2017. This Management Discussion and Analysis ("MD&A") is dated February 13, 2019. All amounts are denominated in Canadian dollars (CDN$) unless otherwise identified.

Financial Highlights	**Three months ended December 31**			**Year ended December 31**			
(stated in thousands, except share and per share amounts)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**	**2016**
Revenue	63,133	66,515	(5%)	236,410	238,175	(1%)	124,438
Operating Revenue(1)	57,806	59,255	(2%)	215,818	218,988	(1%)	116,907
Gross Margin(1)	12,677	15,886	(20%)	50,535	58,310	(13%)	25,762
Gross Margin as a percentage of Operating Revenue	22%	27%	(19%)	23%	27%	(15%)	22%
Adjusted EBITDA(1)	7,916	10,067	(21%)	31,616	35,695	(11%)	5,775
Adjusted EBITDA as a percentage of Operating Revenue	14%	17%	(18%)	15%	16%	(6%)	5%
Cash flow from operating activities	5,022	(800)	(728%)	33,231	24,641	35%	16,631
Capital expenditures	6,102	5,912	3%	19,960	18,132	10%	4,719
Net loss	(9,530)	(4,974)	92%	(41,060)	(37,445)	10%	(61,973)
-basic net loss per share	(0.10)	(0.06)	67%	(0.45)	(0.48)	(6%)	(0.84)
-diluted net loss per share	(0.10)	(0.06)	67%	(0.45)	(0.48)	(6%)	(0.84)
Weighted average number of shares							
-basic	92,305,208	88,812,216	4%	92,224,585	77,601,827	19%	73,703,437
-diluted	92,305,208	88,812,216	4%	92,224,585	77,601,827	19%	73,703,437
Outstanding common shares as at period end	92,305,542	92,175,598	-	92,305,542	92,175,598	-	73,795,944
Operating Highlights(1)							
Contract Drilling							
Canadian Operations							
Average active rig count	18.1	21.6	(16%)	19.2	20.6	(7%)	10.0
Operating Revenue per Billable Day	19,622	18,807	4%	18,922	17,558 (3)	8%	16,984 (4)
Operating Revenue per Operating Day	21,973	21,100	4%	20,984	19,446 (3)	8%	19,058 (4)
Drilling rig utilization - Billable Days	36%	43%	(16%)	38%	41%	(7%)	20%
Drilling rig utilization - Operating Days	32%	38%	(16%)	35%	37%	(5%)	17%
CAODC industry average utilization - Operating Days(2)	28%	28%	-	29%	29%	-	17%
United States Operations							
Average active rig count	4.9	4.0	23%	3.4	3.1	10%	1.4
Operating Revenue per Billable Day (US$)	19,756	18,038	10%	20,227	19,198	5%	21,805
Operating Revenue per Operating Day (US$)	22,183	21,265	4%	22,586	22,338	1%	25,166
Drilling rig utilization - Billable Days	79%	75%	5%	57%	61%	(7%)	28%
Drilling rig utilization - Operating Days	71%	63%	13%	51%	52%	(2%)	24%
Production Services							
Average active rig count	18.8	17.0	11%	16.5	17.2	(4%)	12.9
Service rig Operating Revenue per Service Hour	667	708	(6%)	683	673	1%	643
Service rig utilization	28%	26%	9%	25%	26%	(4%)	20%

(1) See "Non-IFRS Measures" on page 21 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 year ended December 31, 2017.

(4) Excludes shortfall commitment revenue from take or pay contracts of $1.8 million for the year ended December 31, 2016.

Financial Position at (stated in thousands)	December 31, 2018	December 31, 2017	December 31, 2016
Working capital	15,739	62,866	51,118
Property and equipment	615,395	652,828	708,567
Total assets	667,295	760,504	793,525
Long term debt	222,258	265,219	264,070

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 21 of this MD&A. Abbreviations for standard industry terms are included on page 23 of this MD&A.

Western has a drilling rig fleet of 57 rigs specifically suited for drilling complex horizontal wells. Western is currently the fourth largest drilling contractor in Canada, based on the Canadian Association of Oilwell Drilling Contractors ("CAODC") registered rigs, with a fleet of 49 rigs operating through Horizon. Of the Canadian fleet, 23 are classified as Cardium class rigs, 19 as Montney class rigs and seven as Duvernay class rigs. As compared to the Cardium class rigs, the Montney class rigs have a larger hookload, while the Duvernay class rigs have the largest hookload allowing the rig to support more drill pipe downhole. Additionally, Western has eight drilling rigs operating through Stoneham in the US, including six Duvernay class rigs. Western is also the fifth largest well servicing company in Canada with a fleet of 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 months ended December 31, 2018 and 2017 and for the years ended December 31, 2018 and 2017.

	Three months ended December 31			Year ended December 31		
	2018	2017	Change	2018	2017	Change
Average crude oil and natural gas prices(1)(2)						
Crude Oil						
West Texas Intermediate (US$/bbl)	59.32	55.28	7%	64.95	50.81	28%
Western Canadian Select (CDN$/bbl)	33.91	49.10	(31%)	49.97	49.49	1%
Natural Gas						
30 day Spot AECO (CDN$/mcf)	1.61	1.67	(4%)	1.53	2.23	(31%)
Average foreign exchange rates(2)						
US dollar to Canadian dollar	1.32	1.27	4%	1.30	1.30	-

(1) See "Abbreviations" on page 23 of this MD&A.

(2) Source: Bloomberg

West Texas Intermediate ("WTI") on average improved by 7% and 28% for the three months and year ended December 31, 2018 respectively, compared to the same periods in the prior year. However, pricing on Canadian crude oil collapsed in the fourth quarter of 2018, resulting in record differentials. As a result, the price for Western Canadian Select ("WCS") decreased by 31% for the three months ended December 31, 2018, as compared to the same period in the prior year, while on a year over year basis WCS improved by only 1%. The United States dollar to Canadian dollar foreign exchange rate remained constant year over year, though the weakening of the Canadian dollar in the fourth quarter of 2018 had a slightly positive effect on the cash flows of Western's Canadian customers, when selling United States dollar denominated commodities. Natural gas prices declined for both the three months and year ended December 31, 2018, as the 30 day spot AECO price decreased by 4% and 31% respectively, over the same periods of the prior year, however fourth quarter 2018 average AECO prices improved by 28% as compared to the third quarter of 2018.

In the United States, improved market conditions in 2018 led to a corresponding increase in the demand for oilfield services. As reported by Baker Hughes, a GE Company, the average number of active drilling rigs in the United States increased approximately 18% in 2018 as compared to 2017. However, market conditions in Canada did not improve. Higher WTI prices were largely offset by increased differentials on Canadian crude oil, which hit record highs in the fourth quarter of 2018, prior to narrowing upon the announcement of mandatory crude oil production curtailments by the Government of Alberta. This intervention increased market uncertainty, so the higher pricing did not correspond to higher activity. Additionally, the continued industry concerns over market access, increased regulation, and the prevailing customer preference to return cash to shareholders, or pay down debt, rather than grow production have resulted in a decrease in industry activity in Canada. The CAODC reported that for drilling in Canada, the total number of Operating Days in the Western Canadian Sedimentary Basin ("WCSB") decreased by approximately 3% in 2018 as compared to 2017.

Operational results for the three months ended December 31, 2018 include:

- Fourth quarter Operating Revenue decreased by $1.5 million to $57.8 million in 2018 as compared to $59.3 million in 2017. In the contract drilling segment, Operating Revenue totalled $44.5 million in the fourth quarter of 2018, a decrease of $1.4 million (or 3%) as compared to $45.9 million in the fourth quarter of 2017. In the production services segment, Operating Revenue totalled $13.3 million for the three months ended December 31, 2018, as compared to $13.4 million in the three months ended December 31, 2017, a decrease of $0.1 million (or 1%). While pricing improved in the contract drilling segment and activity was higher for contract drilling in the United States and well servicing in Canada, lower contract drilling activity in Canada, decreased oilfield rental equipment activity, and lower pricing in the production services segment, impacted Operating Revenue as described below:
    - Drilling rig utilization – Operating Days ("Drilling Rig Utilization") in Canada decreased to 32% in the fourth quarter of 2018 compared to an average of 38% in the same period of the prior year, reflecting a 600 basis points ("bps") reduction. The decrease in activity was mainly attributable to record high differentials on Canadian crude oil realized in the fourth quarter of 2018 and heightened market uncertainty. As a result, customers were quick to delay or cancel their drilling programs in the fourth quarter of 2018. Fourth quarter 2018 Drilling Rig Utilization of 32% represented a premium of 400 bps to the CAODC industry average of 28%, a decrease as compared to the fourth quarter of 2017 when Drilling Rig Utilization of 38% represented a premium of 1,000 bps to the industry average. The decrease in the Company's utilization premium to the industry average in 2018 was 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 consistent at 10% in both the fourth quarter of 2018 and 2017. Pricing continued to increase and resulted in a 4% improvement in Operating Revenue per Billable Day in the fourth quarter of 2018, as compared to the same period in the prior year. The increase in pricing was a result of the Company being successful in steadily raising rates in 2018 prior to demand decreasing in the fourth quarter of 2018;
    - In the United States, improved WTI prices led to six of the Company's seven drilling rigs operating during the quarter, three of which were working on long term contracts. During the fourth quarter of 2018, the Company purchased one Cardium class drilling rig for its fleet in the United States, which commenced operations in the Permian basin at the end of the fourth quarter. As a result of improved WTI pricing and a larger rig fleet, Operating Days increased by 29% in the fourth quarter of 2018, as compared to the same period in the prior year. As a result, Drilling Rig Utilization improved to 71% in the fourth quarter of 2018, compared to 63% in the same period of the prior year. Operating Revenue per Billable Day for the fourth quarter of 2018 improved by 10% as compared to the fourth quarter of 2017, as the improved commodity price environment led to increased demand and resulted in day rate increases on contracted rigs; and
    - Service rig utilization was 28% in the fourth quarter of 2018 compared to 26% in the same period of the prior year. The increase is due to continued marketing efforts to broaden the Company's customer base, despite customer programs being impacted significantly by record high crude oil differentials in the fourth quarter of 2018. While utilization improved, service rig Operating Revenue per Service Hour decreased during the fourth quarter of 2018 by 6% as compared to the same period in the prior year, due to changes in the average rig mix. Higher utilization, offset partially by lower pricing, led to well servicing Operating Revenue in the period increasing to $11.5 million, an improvement of $0.4 million (or 4%), as compared to the same period in the prior year.
- Fourth quarter Adjusted EBITDA decreased by $2.2 million (or 21%) to $7.9 million in 2018 as compared to $10.1 million in the fourth quarter of 2017. The year over year change in Adjusted EBITDA is due to lower activity in the contract drilling segment in Canada, decreased oilfield rental equipment activity, and decreased well servicing hourly

rates, which was offset partially by improved pricing in the contract drilling segment and higher utilization in the United States and well servicing in Canada.

- Administrative expenses, excluding depreciation and stock based compensation, decreased by $1.0 million (or 17%) to $4.8 million, as compared to $5.8 million in the fourth quarter of 2017, mainly due to lower employee related costs.
- The Company incurred a net loss of $9.5 million in the fourth quarter of 2018 ($0.10 per basic common share) as compared to a net loss of $5.0 million in the same period in 2017 ($0.06 per basic common share). The change can be attributed to the following:
  - A $3.2 million decrease in income tax recovery due to the decrease in the federal corporate tax rates in the United States in 2017 from 35.0% to 21.0%, which resulted in a significant recovery in the prior period;
  - A $2.2 million decrease in Adjusted EBITDA, mainly due to lower oilfield rental equipment activity and lower utilization in the contract drilling segment in Canada, offset partially by higher utilization in the United States and in well servicing in Canada; and
  - A $0.6 million increase 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 finance costs, due to lower total debt levels and a lower average interest rate.
- Fourth quarter 2018 capital expenditures of $6.1 million included $4.1 million of expansion capital and $2.0 million of maintenance capital. In total, capital spending in the fourth quarter of 2018 increased by $0.2 million from the $5.9 million incurred in the fourth quarter of 2017. The Company incurred expansion capital mainly related to drilling rig upgrades, including the acquisition and upgrade of one Cardium class rig in the Permian Basin, as well as required maintenance capital, in the fourth quarter of 2018.
- On December 12, 2018, the Company completed a number of amendments to its syndicated first lien credit facility (the “Revolving Facility”) and its committed operating facility (the “Operating Facility” and together the “Credit Facilities”), including the following:
  - Extended the maturity of its Credit Facilities to December 17, 2021;
  - Elected to reduce the commitment under the Revolving Facility from $70.0 million to $50.0 million. The commitment under the Operating Facility remains unchanged at $10.0 million;
  - The minimum debt service coverage ratio financial covenant was removed; and
  - A current ratio financial covenant was added whereby Western’s current ratio, excluding the current portion of long term debt and accrued interest, must meet or exceed 1.15.

Operational results for the year ended December 31, 2018 include:

- Operating Revenue in 2018 decreased by $3.2 million (or 1%) to $215.8 million as compared to $219.0 million in 2017. However, after normalizing for $6.4 million of shortfall commitment revenue recognized in the first quarter of 2017, Operating Revenue in 2018 improved by $3.2 million (or 2%). In the contract drilling segment, Operating Revenue totalled $165.7 million in 2018, which after normalizing for $6.4 million of shortfall commitment revenue recognized in 2017, resulted in Operating Revenue improving by $5.4 million (or 3%). In the production services segment, Operating Revenue totalled $50.3 million in 2018, as compared to $52.5 million in 2017, a decrease of $2.2 million (or 4%). While on a year to date basis activity was lower in Canada, activity in the United States increased and pricing in all divisions improved which impacted Operating Revenue as described below:
  - Drilling Rig Utilization in Canada for the year ended December 31, 2018 averaged 35%, compared to an average of 37% for the prior year, reflecting a 200 bps decrease. The decrease in activity was due to some of Western’s customers deferring or cancelling their drilling plans, particularly in the fourth quarter of 2018, amid high differentials on Canadian crude oil and low natural gas prices. Drilling Rig Utilization of 35% in 2018 represented a premium of 600 bps to the CAODC industry average of 29%, whereas in 2017, Drilling Rig Utilization of 37% represented an 800 bps premium to the industry average. The decrease in the Company’s utilization premium to the industry average in 2018 was 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 consistent at 10% in both 2018 and 2017. While utilization decreased during 2018, pricing continued to increase and resulted in an 8% improvement in Operating Revenue per Billable Day in 2018, as compared to 2017. The increase in pricing is a result of the Company being successful in steadily raising rates in 2018 prior to demand decreasing in the fourth quarter of 2018;

- In the United States, improved WTI prices led to six of the Company's seven drilling rigs operating during the year. Late in the fourth quarter of 2018, the Company added a Cardium class drilling rig to its fleet in the United States, which began work in the Permian basin. As a result of improved WTI pricing and a larger rig fleet, Operating Days increased by 16% in 2018, as compared to 2017. While activity increased, Drilling Rig Utilization decreased marginally to 51% for the year ended December 31, 2018, as compared to 52% in the prior year, due to an increased rig fleet as two Cardium class drilling rigs were added to the fleet, one in late 2017 and the other in late 2018. Operating Revenue per Billable Day in the United States improved by 5% in 2018, as compared to 2017, as the improved commodity price environment led to increased demand and resulted in day rate increases; and
- Service rig utilization of 25% for the year ended December 31, 2018 compared to 26% in the prior year. Over the last nine months of 2018, well servicing activity improved over the same period of the prior year due to the continued marketing efforts to broaden the Company's customer base. However, on a year over year basis, activity is down due to operating hours being lower in the first quarter of 2018. Hourly rates improved in 2018, increasing by 1% as compared to 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 $1.2 million (or 3%) decrease in well servicing Operating Revenue in 2018.

- Adjusted EBITDA for the year ended December 31, 2018 decreased by $4.1 million (or 11%) to $31.6 million as compared to $35.7 million in 2017. However, after normalizing for the $6.4 million in shortfall commitment revenue recognized in the first quarter of 2017, Adjusted EBITDA improved by $2.3 million (or 8%) in 2018, as compared to the prior year. The year over year decrease in Adjusted EBITDA is due to lower activity and shortfall commitment revenue in Canada, offset by improved pricing in all divisions and increased activity in the United States.
- Administrative expenses in 2018, excluding depreciation and stock based compensation, decreased by $3.7 million (or 16%) to $18.9 million, as compared to $22.6 million in 2017, mainly due to lower employee related costs.
- The Company incurred a net loss of $41.1 million in 2018 ($0.45 per basic common share) as compared to a net loss of $37.4 million in 2017 ($0.48 per basic common share). The change can be attributed to the following:
  - A $4.1 million decrease in Adjusted EBITDA, mainly due to lower shortfall commitment revenue; and
  - A $4.9 million decrease in income tax recovery mainly due to the decrease in the federal corporate tax rates in the United States in 2017 from 35.0% to 21.0%, which resulted in a significant recovery in the prior period.

  Offsetting the above mentioned items was:
  - A $1.5 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 $2.9 million decrease in finance costs, due to lower total debt levels; and
  - A $0.8 million decrease in stock based compensation expense.
- Year to date capital expenditures of $20.0 million included $11.5 million of expansion capital and $8.5 million of maintenance capital. In total, capital spending in 2018 increased by $1.9 million from the $18.1 million incurred in 2017. The Company incurred expansion capital mainly related to drilling rig upgrades including the purchase and upgrade of one Cardium class rig in the Permian Basin, 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 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. Annual amortization payments equal to 1% of the original principal amount are payable in quarterly installments, which began on July 1, 2018, with the balance due on January 31, 2023.

Outlook

Currently, 27 of Western's drilling rigs are operating. Six of Western's 57 drilling rigs (or 11%) are under long term take or pay contracts, with three expected to expire in 2019, two expected to expire in 2020 and one expected to expire in 2021. These contracts each typically generate between 250 and 350 Billable Days per year.

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

Mandated crude oil production cuts in Alberta and uncertainty surrounding takeaway capacity related to the timing of construction on the Trans Mountain pipeline expansion and the Keystone XL pipeline, have resulted in the announced capital budgets for Western's Canadian customers decreasing year over year in 2019 compared to 2018. As such, activity levels in Canada are expected to decrease in 2019. Controlling fixed costs and maintaining balance sheet flexibility are priorities for the Company, as prices for Western's services remain below historical levels. However, Western's variable cost structure and a prudent capital budget will aid in preserving balance sheet strength. Given the outlook for oilfield services in Canada, Western is proactively looking to deploy existing assets in Canada into more active resource plays in the United States. Early in 2019, Western transferred a Duvernay class drilling rig from Canada to the Permian Basin in the United States, increasing the United States drilling rig fleet to eight rigs. As at December 31, 2018, Western had $11.9 million drawn on its $60.0 million Credit Facilities, which mature on December 17, 2021 and currently has $213.4 million outstanding on its Second Lien Facility, which matures on January 31, 2023.

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

Segmented Information

Western operates in the contract drilling segment 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 December 31**			**Year ended December 31**		
(stated in thousands)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Revenue						
Operating Revenue[1]	44,498	45,906	(3%)	165,684	166,660	(1%)
Third party charges	4,660	6,596	(29%)	18,253	16,282	12%
Total revenue	49,158	52,502	(6%)	183,937	182,942	1%
Expenses						
Operating						
Cash operating expenses	38,072	39,677	(4%)	143,076	137,994	4%
Depreciation	13,112	12,991	1%	52,525	51,905	1%
Stock based compensation	47	49	(4%)	352	129	173%
Total operating expenses	51,231	52,717	(3%)	195,953	190,028	3%
Administrative						
Cash administrative expenses	2,337	2,830	(17%)	9,287	11,245	(17%)
Depreciation	60	55	9%	232	251	(8%)
Stock based compensation	9	54	(83%)	89	188	(53%)
Total administrative expenses	2,406	2,939	(18%)	9,608	11,684	(18%)
Gross Margin[1]	11,086	12,825	(14%)	40,861	44,948	(9%)
Gross Margin as a percentage of Operating Revenue	25%	28%	(11%)	25%	27%	(7%)
Adjusted EBITDA[1]	8,749	9,995	(12%)	31,574	33,703	(6%)
Adjusted EBITDA as a percentage of Operating Revenue	20%	22%	(9%)	19%	20%	(5%)
Operating Loss[1]	(4,423)	(3,051)	45%	(21,183)	(18,453)	15%
Capital expenditures	5,680	4,416	29%	17,759	14,959	19%

Operating Highlights

Canadian Operations						
Contract drilling rig fleet:						
Average active rig count[1]	18.1	21.6	(16%)	19.2	20.6	(7%)
End of period	50	50	-	50	50	-
Operating Revenue per Billable Day[1]	19,622	18,807	4%	18,922	17,558 [3]	8%
Operating Revenue per Operating Day[1]	21,973	21,100	4%	20,984	19,446 [3]	8%
Operating Days[1]	1,487	1,774	(16%)	6,328	6,801	(7%)
Number of meters drilled	529,707	508,552	4%	2,081,121	1,987,020	5%
Number of wells drilled	124	137	(9%)	506	544	(7%)
Average Operating Days per well	12.0	12.9	(7%)	12.5	12.5	-
Drilling rig utilization - Billable Days[1]	36%	43%	(16%)	38%	41%	(7%)
Drilling rig utilization - Operating Days[1]	32%	38%	(16%)	35%	37%	(5%)
CAODC industry average utilization - Operating Days[1][2]	28%	28%	-	29%	29%	-

United States Operations						
Contract drilling rig fleet:						
Average active rig count[1]	4.9	4.0	23%	3.4	3.1	10%
End of period	7	6	17%	7	6	17%
Operating Revenue per Billable Day (US$)[1]	19,756	18,038	10%	20,227	19,198	5%
Operating Revenue per Operating Day (US$)[1]	22,183	21,265	4%	22,586	22,338	1%
Operating Days[1]	403	313	29%	1,121	969	16%
Number of meters drilled	113,979	82,542	38%	343,716	259,918	32%
Number of wells drilled	20	16	25%	64	46	39%
Average Operating Days per well	20.2	19.8	2%	17.5	21.3	(18%)
Drilling rig utilization - Billable Days[1]	79%	75%	5%	57%	61%	(7%)
Drilling rig utilization - Operating Days[1]	71%	63%	13%	51%	52%	(2%)

(1) See "Non-IFRS Measures" on page 21 of this MD&A.

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

(3) Excludes shortfall commitment revenue from take or pay contracts of $6.4 million for the year ended December 31, 2017.

For the year ended December 31, 2018, Operating Revenue in the contract drilling segment totalled $165.7 million, a $1.0 million (or 1%) decrease, as compared to the prior year. Normalizing for $6.4 million in shortfall commitment revenue in 2017, Operating Revenue in 2018 increased by $5.4 million (or 3%), as compared to 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.

Third party charges per Billable Day in the contract drilling segment increased to approximately $2,200 in 2018 as compared to approximately $1,900 in 2017. 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 year ended December 31, 2018, cash operating expenses per Billable Day, excluding third party charges, increased by 7% to $15,096, as compared to $14,054 in the prior year, mainly due higher salaries and related expenses, as well as increased maintenance costs and 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 by 11% for the year ended December 31, 2018, as compared to the prior year, mainly due to improving day rates.

Contract drilling Adjusted EBITDA in 2018 decreased by $2.1 million to $31.6 million, as compared to $33.7 million in 2017. However, after normalizing for $6.4 million of shortfall commitment revenue recognized in the first quarter of 2017, Adjusted EBITDA for the year ended December 31, 2018 increased by $4.3 million (or 16%), as compared to the prior year. On a normalized basis, the increase in 2018 is mainly due to increased pricing in both Canada and the United States and higher activity in the United States, partially offset by lower activity in Canada.

Cash administrative expenses for 2018, which exclude depreciation and stock based compensation, totalled $9.3 million, and were 17% lower than the prior year, mainly due to lower employee related costs.

Depreciation expense in 2018 of $52.8 million reflects an increase of $0.6 million over the prior year, mainly due to capital assets added during the period.

Capital expenditures in the contract drilling segment totalled $17.8 million in 2018 and include $10.7 million of expansion capital and $7.1 million of maintenance capital. Contract drilling capital expenditures for the year ended December 31, 2018 represent an increase of $2.9 million from the $14.9 million incurred in 2017. The Company incurred expansion capital relating to rig upgrades in 2018, including the purchase and upgrade of one Cardium class rig in the Permian Basin, as well as required maintenance capital.

Canadian Operations

During the first three quarters of 2018, the Company was well positioned for the improved drilling environment; however, record high Canadian crude oil differentials and the mandated production cuts announced by the Government of Alberta weakened demand for contract drilling in the fourth quarter of 2018. As a result, Drilling Rig Utilization in Canada decreased to 35% in 2018 as compared to 37% in the prior year.

Drilling Rig Utilization in Canada of 35% in 2018 reflects a 600 bps premium to the CAODC average of 29%, as compared to an 800 bps premium to the CAODC average in the prior year. The decrease in the Company's premium in 2018 as compared to 2017 was 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 constant at 10% in both 2018 and 2017.

For the year ended December 31, 2018, Operating Revenue per Billable Day in Canada improved by 8% and totalled $18,922, compared to $17,558 in 2017. The increase in pricing in 2018 is due to the Company steadily raising rates as the energy industry continued to recover during the first three quarters of 2018 from a multiyear downturn, prior to differentials on Canadian crude oil hitting record highs in the fourth quarter of 2018.

United States Operations

Improved WTI prices led to improved industry demand, including in the Williston basin in North Dakota, where the Company operates six drilling rigs. Active industry drilling rigs in the Williston basin increased by 19% to 56 rigs at December 31, 2018, as compared to 47 rigs at December 31, 2017 per Baker Hughes. The increased demand, coupled with an increased drilling rig fleet led to six of the Company's seven drilling rigs operating during 2018. This resulted in Western's Operating Days in the United States in 2018 increasing by 152 days (or 16%), resulting in Drilling Rig Utilization of 51% compared to 52% in the prior year. The decrease in Drilling Rig Utilization for the year ended December 31, 2018 is mainly due to an increased rig fleet as two Cardium class drilling rigs were added to the fleet, one in the fourth quarter of 2017 and the other in the fourth quarter of 2018. Operating Revenue per Billable Day in 2018 increased by 5% to US$20,227, as compared to US$19,198 in 2017, as the improved commodity price environment led to increased demand and resulted in increased day rates in the United States.

Production Services

Financial Highlights (stated in thousands)	Three months ended December 31 2018	2017	Change	Year ended December 31 2018	2017	Change
Revenue						
Operating Revenue[1]	13,283	13,362	(1%)	50,345	52,456	(4%)
Third party charges	704	664	6%	2,376	2,905	(18%)
Total revenue	13,987	14,026	-	52,721	55,361	(5%)
Expenses						
Operating						
Cash operating expenses	12,397	10,964	13%	43,048	41,998	3%
Depreciation	3,048	3,248	(6%)	12,571	13,323	(6%)
Stock based compensation	11	17	(35%)	54	131	(59%)
Total operating expenses	15,456	14,229	9%	55,673	55,452	-
Administrative						
Cash administrative expenses	1,383	1,561	(11%)	5,341	6,130	(13%)
Depreciation	75	72	4%	318	309	3%
Stock based compensation	3	30	(90%)	23	109	(79%)
Total administrative expenses	1,461	1,663	(12%)	5,682	6,548	(13%)
Gross Margin[1]	1,590	3,062	(48%)	9,673	13,363	(28%)
Gross margin as a percentage of Operating Revenue	12%	23%	(48%)	19%	25%	(24%)
Adjusted EBITDA[1]	207	1,501	(86%)	4,332	7,233	(40%)
Adjusted EBITDA as a percentage of Operating Revenue	2%	11%	(82%)	9%	14%	(36%)
Operating Loss[1]	(2,916)	(1,819)	60%	(8,557)	(6,399)	34%
Capital expenditures	422	1,338	(68%)	2,201	3,013	(27%)
Operating Highlights						
Well servicing rig fleet:						
Average active rig count[1]	18.8	17.0	11%	16.5	17.2	(4%)
End of period	66	66	-	66	66	-
Service rig Operating Revenue per Service Hour[1]	667	708	(6%)	683	673	1%
Service Hours[1]	17,247	15,650	10%	60,337	62,946	(4%)
Service rig utilization [1]	28%	26%	9%	25%	26%	(4%)

(1) See "Non-IFRS Measures" on page 21 of this MD&A.

The Company's production services segment includes Eagle's well servicing fleet as well as Aero's oilfield rental equipment. Operating Revenue in the production services segment for the year ended December 31, 2018, decreased by $2.2 million (or 4%) to $50.3 million, compared to $52.5 million in the prior year. In 2018, Eagle's contribution to Operating Revenue in the production services segment was $41.2 million compared to $42.4 million in the prior year, whereas Aero's contribution to Operating Revenue in the production services segment was $9.1 million compared to $10.1 million in the prior year. The decrease in Operating Revenue for both Eagle and Aero in 2018, as compared to 2017, is due to reduced industry activity.

Eagle's Service Hours decreased by 4% to 60,337 hours (25% utilization) in 2018, as compared to 62,946 hours (26% utilization) in 2017. Over the last nine months of 2018, well servicing activity improved over the same period of the prior year due to the continued marketing efforts to broaden the Company's customer base. However, on a year over year basis, activity is down due to operating hours being lower in the first quarter of 2018. Service rig Operating Revenue per Service Hour increased by 1% to $683 in 2018, as compared to $673 in the prior year, due to changes in the average rig mix.

Adjusted EBITDA decreased by $2.9 million (or 40%) to $4.3 million in 2018, compared to $7.2 million in 2017. The lower Adjusted EBITDA in 2018 was mainly due to lower demand for the Company's oilfield rental equipment and reduced service rig activity.

During the year ended December 31, 2018, cash administrative expenses, which exclude depreciation and stock based compensation, totalled $5.3 million and were 13% lower than the prior year, mainly due to lower employee related costs.

Depreciation expense for 2018 decreased by 5% to $12.9 million, as compared to $13.6 million in 2017, due to certain capital assets being fully depreciated in the year.

During the year ended December 31, 2018, capital expenditures in the production services segment totalled $2.2 million, as compared to $3.0 million in the prior year, and included expansion capital of $0.8 million and maintenance capital of $1.4 million.

Corporate

	Three months ended December 31			Year ended December 31		
(stated in thousands)	**2018**	**2017**	**Change**	**2018**	**2017**	**Change**
Administrative						
Cash administrative expenses	1,040	1,428	(27%)	4,290	5,240	(18%)
Depreciation	136	157	(13%)	535	653	(18%)
Stock based compensation	84	313	(73%)	660	1,392	(53%)
Total administrative expenses	1,260	1,898	(34%)	5,485	7,285	(25%)
Finance costs	4,603	5,598	(18%)	19,050	21,950	(13%)
Other items	(101)	(700)	(86%)	(99)	1,356	(107%)
Income taxes						
Current tax (recovery) expense	(21)	42	(150%)	(66)	75	(188%)
Deferred tax recovery	(3,620)	(6,884)	(47%)	(13,568)	(18,630)	(27%)
Total income taxes	(3,641)	(6,842)	(47%)	(13,634)	(18,555)	(27%)
Operating Loss[1]	(1,176)	(1,585)	(26%)	(4,825)	(5,893)	(18%)

(1) See "Non-IFRS Measures" on page 21 of this MD&A.

Corporate cash administrative expenses, which exclude depreciation and stock based compensation, decreased by 18% to $4.3 million, as compared to the prior year, mainly due to lower employee related costs.

Finance costs in 2018 of $19.1 million were lower by $2.9 million (or 13%) as compared to 2017, due to the decreased total debt level on the Second Lien Facility, as compared to the previously outstanding Senior Notes. The Company refinanced its $265.0 million 7⅞% Senior Notes on February 1, 2018 with a combination of cash on hand, available Credit Facilities and the proceeds from the $215.0 million 7.25% Second Lien Facility draw. The Second Lien Facility was drawn on January 31, 2018 and currently has a principal balance outstanding of $213.4 million. The Company had an effective interest rate on its borrowings of 8.5% throughout 2018, as compared to 8.3% throughout 2017. The increase in the effective interest rate in 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 7.6% throughout 2018, as compared to 8.0% in 2017.

Other items, which relate to gains and losses on the sale of assets and foreign exchange, total a $0.1 million gain in 2018 as compared to a loss of $1.4 million in 2017, which included $1.6 million of transaction costs in the first quarter of 2017 related to an unsuccessful transaction.

For the year ended December 31, 2018, income taxes on a consolidated basis totalled a recovery of $13.6 million, representing an effective tax rate of 24.9%, as compared to an effective tax rate of 33.1% in 2017. The Company's effective tax rate in 2017 was impacted by a decrease in the federal corporate tax rates in the United States from 35.0% to 21.0%. Normalizing for the impact of the United States tax reform, the Company's effective tax rate in 2017 would have been 26.9%.

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 December 31, 2018, Western had working capital of $15.7 million, a decrease of $47.2 million from December 31, 2017. The decrease in working capital is mainly due to lower cash balances as a portion of the available cash balances on hand at December 31, 2017 was used to repay the Senior Notes on February 1, 2018. Western's consolidated debt balance at December 31, 2018 decreased by $38.7 million (or 14%) to $227.6 million, as compared to $266.3 million at December 31, 2017, due to refinancing the $265.0 million Senior Notes with the $215.0 million Second Lien Facility in the first quarter of 2018.

During the year ended December 31, 2018, Western had the following changes to its cash balances, which resulted in a $44.9 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	31,616
Draw on Credit Facilities	11,891
Change in non cash working capital	1,255
Proceeds on sale of property and equipment	659
Deduct:	
Repayment of Senior Notes	(265,000)
Finance costs paid	(18,362)
Additions to property and equipment	(19,960)
Repayment of Second Lien Facility	(1,075)
Repayment of other long term debt	(596)
Other items	(293)
Ending balance, at December 31, 2018	**3,960**

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

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

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

As at December 31, 2018, the borrowing base calculation was not applicable as less than $40.0 million was drawn on the Company's Credit Facilities and the net book value of Western's property and equipment was greater than $300.0 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 21 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 December 31, 2018 is as follows:

December 31, 2018	**Covenants (1)**
Maximum Consolidated Senior Debt to Consolidated EBITDA Ratio	3.0:1.0 or less
Maximum Consolidated Debt to Consolidated Capitalization Ratio	0.6:1.0 or less
Minimum Current Ratio	1.15:1.0 or more

(1) See covenant definitions in Note 11 of the December 31, 2018 consolidated financial statements.

At December 31, 2018, Western is in compliance with all covenants related to its Credit Facilities.

For the years ended December 31, 2018 and 2017, the Company had no customers comprising 10.0% or more of the Company's total revenue. The Company's significant customers may change from period to period.

Review of Fourth Quarter 2018 Results

Selected Financial Information

Financial Highlights	**Three months ended December 31**		
(stated in thousands, except share and per share amounts)	**2018**	**2017**	**Change**
Total Revenue	63,133	66,515	(5%)
Operating Revenue	57,806	59,255	(2%)
Gross Margin[1]	12,677	15,886	(20%)
Gross Margin as a percentage of Operating Revenue	22%	27%	(19%)
Adjusted EBITDA[1]	7,916	10,067	(21%)
Adjusted EBITDA as a percentage of Operating Revenue	14%	17%	(18%)
Cash flow from operating activities	5,022	(800)	(728%)
Capital expenditures	6,102	5,912	3%
Net loss	(9,530)	(4,974)	92%
-basic net loss per share	(0.10)	(0.06)	67%
-diluted net loss per share	(0.10)	(0.06)	67%
Weighted average number of shares			
-basic	92,305,208	88,812,216	4%
-diluted	92,305,208	88,812,216	4%
Outstanding common shares as at period end	92,305,542	92,175,598	-

Operating Highlights			
Contract Drilling			
Canadian Operations			
Contract drilling rig fleet:			
Average active rig count[1]	18.1	21.6	(16%)
End of period	50	50	-
Operating Revenue per Billable Day[1]	19,622	18,807	4%
Operating Revenue per Operating Day[1]	21,973	21,100	4%
Operating Days[1]	1,487	1,774	(16%)
Number of meters drilled	529,707	508,552	4%
Number of wells drilled	124	137	(9%)
Average Operating Days per well	12.0	12.9	(7%)
Drilling rig utilization - Billable Days[1]	36%	43%	(16%)
Drilling rig utilization - Operating Days[1]	32%	38%	(16%)
CAODC industry average utilization rate[2]	28%	28%	-
United States Operations			
Contract drilling rig fleet:			
Average active rig count[1]	4.9	4.0	23%
End of period	7	6	17%
Operating Revenue per Billable Day[1]	19,756	18,038	10%
Operating Revenue per Operating Day (US$)[1]	22,183	21,265	4%
Operating Days[1]	403	313	29%
Number of meters drilled	113,979	82,542	38%
Number of wells drilled	20	16	25%
Average Operating Days per well	20.2	19.8	2%
Drilling rig utilization - Billable Days[1]	79%	75%	5%
Drilling rig utilization - Operating Days[1]	71%	63%	13%
Production Services			
Well servicing rig fleet:			
Average active rig count[1]	18.8	17.0	11%
End of period	66	66	-
Service rig Operating Revenue per Service Hour[1]	667	708	(6%)
Service Hours[1]	17,247	15,650	10%
Service rig utilization[1]	28%	26%	9%

(1) See "Non-IFRS Measures" on page 21 of this MD&A.

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

Review of Fourth Quarter 2018 Results

Consolidated

Fourth quarter Operating Revenue decreased by $1.5 million (or 2%) to $57.8 million in 2018 as compared to $59.3 million in the same period of the prior year. Adjusted EBITDA decreased by $2.2 million (or 21%) to $7.9 million in the fourth quarter of 2018, as compared to $10.1 million in the fourth quarter of 2017. The decrease in consolidated Operating Revenue and Adjusted EBITDA is mainly a result of lower utilization in the contract drilling segment in Canada and decreased oilfield rental equipment activity in the production services segment, offset partially by higher utilization in the United States and increased well servicing activity.

Contract Drilling

During the fourth quarter of 2018, Operating Revenue in the contract drilling segment totalled $44.5 million, a $1.4 million decrease (or 3%), as compared to the same period of the prior year. The fourth quarter of 2018 was impacted by lower industry activity in Canada as Canadian crude oil differentials widened significantly, while improved market conditions in the United States led to higher year over year activity. Pricing in both Canada and the United States in the fourth quarter of 2018 continued to improve, as compared to the same period in the prior year.

For the three months ended December 31, 2018, third party charges per Billable Day in the contract drilling segment decreased to approximately $2,200, as compared to approximately $2,700 in the same period of the prior year. The decrease is mainly due to higher trucking costs incurred in the fourth quarter of 2017.

For the three months ended December 31, 2018, cash operating expenses per Billable Day in the contract drilling segment, excluding third party charges, increased by 13% to $15,777, as compared to $14,018 in the same period of the prior year. The increase is mainly due to higher salaries and related expenses, as well as increased maintenance costs and fixed operating costs being allocated over fewer Billable Days in 2018, as compared to 2017.

Gross Margin per Billable Day decreased for the three months ended December 31, 2018 by 4%, as compared to the same period of the prior year, mainly due to the decrease in activity in the fourth quarter of 2018 resulting in fixed operating costs being allocated over fewer billable days.

Contract drilling Adjusted EBITDA for the three months ended December 31, 2018 decreased by $1.2 million to $8.8 million, as compared to $10.0 million in the same period of the prior year. The decrease is mainly due to lower activity in Canada, offset partially by higher day rates in both Canada and the United States and increased activity in the United States.

For the three months ended December 31, 2018, cash administrative expenses, which exclude depreciation and stock based compensation, totalled $2.3 million and were 17% lower than the same period of the prior year, mainly due to lower employee related costs.

Depreciation expense for the quarter ended December 31, 2018 totalled $13.2 million and reflects an increase of $0.2 million over the same period of the prior year, mainly due to capital assets added during 2018.

Capital expenditures in the contract drilling segment totalled $5.7 million in the fourth quarter of 2018 and include $4.0 million of expansion capital and $1.7 million of maintenance capital. Contract drilling capital expenditures represent an increase of $1.3 million from the $4.4 million incurred in the three months ended December 31, 2017. The Company incurred expansion capital relating to rig upgrades in 2018, including the purchase and upgrade of one Cardium class rig in the Permian Basin, as well as required maintenance capital.

Canadian Operations

Canadian crude oil differentials increased significantly during the fourth quarter of 2018 and resulted in a decrease in the absolute price for Canadian crude oil despite the price of WTI increasing. As a result, during the three months ended December 31, 2018, Operating Days decreased by 16% and Drilling Rig Utilization in Canada declined to 32% as compared to 38% in the same period of the prior year. The decrease in activity is attributable to some of Western's customers deferring their drilling plans amid record high differentials on Canadian crude oil and low natural gas prices.

Drilling Rig Utilization in Canada of 32% in the fourth quarter of 2018 reflects a 400 bps premium to the CAODC average of 28%, as compared to a 1,000 bps premium to the CAODC average of 28% in the fourth quarter of 2017. The decrease in the Company's premium to the CAODC average for the three months ended December 31, 2018 was due to 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 consistent at 10% in both the fourth quarter of 2018 and 2017.

Operating Revenue per Billable Day in Canada improved by 4% and totalled $19,622, compared to $18,807 in the same period of the prior year. The increase in pricing year over year was due to the Company being successful in steadily raising rates in 2018 prior to demand decreasing in the fourth quarter of 2018.

United States Operations

Improved WTI prices and an increased drilling rig fleet led to six of the Company's seven drilling rigs operating during the three months ended December 31, 2018. This resulted in Western's Operating Days in the United States, in the fourth quarter of 2018, increasing by 90 days (or 29%) which resulted in Drilling Rig Utilization of 71%, compared to 63% in the same period of the prior year. Operating Revenue per Billable Day improved by 10% in the fourth quarter of 2018 to total US$19,756 as compared to US$18,038 in the fourth quarter of 2017, as the improved commodity price environment led to increased demand and resulted in day rate increases in the United States.

Production Services

Operating Revenue for the quarter ended December 31, 2018 decreased by $0.1 million (or 1%) to $13.3 million, compared to $13.4 million in the same period of the prior year. In the fourth quarter of 2018, Eagle's contribution to Operating Revenue in the production services segment improved by 4% to $11.5 million compared to $11.1 million in the prior year, whereas Aero's contribution to Operating Revenue in the production services segment decreased by 22% to $1.8 million in the fourth quarter of 2018 compared to $2.3 million in the same period of the prior year. The increase in Operating Revenue for Eagle for the three months ended December 31, 2018, as compared to the same period in the prior year, is due to improved activity offset partially by lower hourly rates, whereas Aero's Operating Revenue decreased for the three months ended December 31, 2018 due to weaker demand.

Eagle's Service Hours increased by 10% to 17,247 hours (28% utilization) in the fourth quarter of 2018, as compared to 15,650 hours (26% utilization) in the same period of the prior year. The increase in Service Hours for the three month period ended December 31, 2018 is mainly due to continued marketing efforts to broaden the Company's customer base, despite customer programs being impacted significantly by high crude oil differentials. Service rig Operating Revenue per Service Hour decreased by 6% to $667 for the three months ended December 31, 2018, as compared to the same period in the prior year, due to changes in the average rig mix.

Adjusted EBITDA decreased in the fourth quarter of 2018 by $1.3 million (or 86%) to $0.2 million, compared to $1.5 million in the same period of the prior year. The lower Adjusted EBITDA for the quarter ended December 31, 2018 was mainly due to reduced demand for Aero's oilfield rental equipment.

Cash administrative expenses, which exclude depreciation and stock based compensation, totalled $1.4 million in the fourth quarter of 2018 and were 11% lower than the same period in the prior year, mainly due to lower employee related costs.

Depreciation expense in the fourth quarter of 2018 decreased by 6% to $3.1 million, as compared to $3.3 million in the same period of the prior year, due to certain capital assets being fully depreciated in the period.

During the three months ended December 31, 2018, capital expenditures in the production services segment totalled $0.4 million, as compared to $1.3 million for the three months ended December 31, 2017, and included expansion capital of $0.1 million and maintenance capital of $0.3 million.

Corporate

Corporate cash administrative expenses, which exclude depreciation and stock based compensation, for the three months ended December 31, 2018 decreased by 27%, as compared to the same period in the prior year and totalled $1.0 million, mainly due to lower employee related costs.

Finance costs for the three months ended December 31, 2018, were lower than the same period of the prior year, due to the decreased total debt level and lower interest rate on the Second Lien Facility, as compared to the previously outstanding Senior Notes. The Company had an effective interest rate on its borrowings of 8.1% for the three months ended December 31, 2018, as compared to 8.4% in the same period of the prior year.

Other items for the three months ended December 31, 2018 total a gain of $0.1 million, as compared to a gain of $0.7 million in the same period of the prior year, and include gains and losses on foreign exchange and asset sales.

For the fourth quarter of 2018, income taxes on a consolidated basis totalled a recovery of $3.6 million, representing an effective tax rate of 27.6%, as compared to an effective tax rate of 57.9% in the fourth quarter of 2017. The effective tax rate in the fourth quarter of 2017 was impacted by the decrease in the federal corporate tax rate in the United States from 35.0% to 21.0%. Normalizing for the United States tax reform, the Company's fourth quarter 2017 effective tax rate would have been 26.0%.

Summary of Quarterly Results

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

Three months ended (stated in thousands, except per share amounts)	**Dec 31, 2018**	**Sep 30, 2018**	**Jun 30, 2018**	**Mar 31, 2018**	**Dec 31, 2017**	**Sep 30, 2017**	**Jun 30, 2017**	**Mar 31, 2017**
Revenue	63,133	58,879	33,141	81,257	66,515	54,131	33,307	84,222
Operating Revenue(1)	57,806	54,071	30,976	72,965	59,255	51,111	30,469	78,153
Gross Margin(1)	12,677	12,025	5,562	20,271	15,886	12,299	5,667	24,458
Adjusted EBITDA(1)	7,916	7,691	897	15,112	10,067	6,882	121	18,625
Cash flow from operating activities	5,022	(1,968)	26,313	3,864	(800)	1,609	20,659	3,173
Net loss	(9,530)	(10,108)	(15,475)	(5,947)	(4,974)	(11,478)	(16,628)	(4,365)
per share - basic	(0.10)	(0.11)	(0.17)	(0.06)	(0.06)	(0.16)	(0.23)	(0.06)
per share - diluted	(0.10)	(0.11)	(0.17)	(0.06)	(0.06)	(0.16)	(0.23)	(0.06)
Total assets	667,295	669,079	670,584	706,895	760,504	737,385	758,278	785,040
Long term debt	222,258	222,564	210,944	227,401	265,219	264,958	264,702	264,150

(1) See "Non-IFRS Measures" on page 21 of this MD&A.

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

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

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

Commitments

In the normal course of business the Company incurs commitments related to its contractual obligations. The expected maturities of the Company's contractual obligations as at December 31, 2018 are as follows:

(stated in thousands)	2019	2020	2021	2022	2023	Thereafter	Total
Second Lien Facility	2,150	2,150	2,150	2,150	205,325	-	213,925
Second Lien Facility interest	15,448	15,376	15,179	15,105	7,473	-	68,581
Trade payables and other current liabilities (1)	25,946	-	-	-	-	-	25,946
Operating leases	4,707	4,407	3,390	3,078	2,752	2,773	21,107
Revolving Facility	-	-	11,000	-	-	-	11,000
Purchase commitments	1,924	-	-	-	-	-	1,924
Operating Facility	-	-	891	-	-	-	891
Other long term debt	661	838	454	-	-	-	1,953
Total	50,836	22,771	33,064	20,333	215,550	2,773	345,327

(1) Trade payables and other current liabilities exclude the Company's interest accrued as at December 31, 2018 on the Second Lien Facility.

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

Trade payables and other current liabilities:
The Company has recorded trade payables for amounts due to third parties which are expected to be paid within one year.

Operating leases:
The Company has offices and oilfield service equipment under operating leases. The leases typically run for a period of one to ten years, typically with an option to renew the lease after that date.

Purchase commitments:
The Company has agreements in place to purchase certain capital and other operational items with third parties.

Other long term debt:
The Company has other long term debt relating to leased vehicles.

There have been no material changes in the contractual obligations, other than in the normal course of business, subsequent to December 31, 2018.

Outstanding Share Data

	February 13, 2019	December 31, 2018	December 31, 2017
Common shares outstanding	92,307,042	92,305,542	92,175,598
Warrants	7,099,546	7,099,546	7,099,546
Stock options outstanding	7,763,634	8,313,537	6,475,613
Restricted share units outstanding - equity settled	534,110	543,997	191,420

Off Balance Sheet Arrangements

As at December 31, 2018, Western had no off balance sheet arrangements in place.

Transactions with Related Parties

During the years ended December 31, 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

The President and Chief Executive Officer ("CEO") and Senior Vice President, Finance, Chief Financial Officer & Corporate Secretary ("CFO") of Western are responsible for establishing and maintaining disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR") for the Company.

DC&P is designed to provide reasonable assurance that material information relating to the Company is made known to the CEO and CFO by others, particularly in the period in which the annual filings are being prepared, and that information required to be disclosed in documents filed with securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified in securities legislation, and includes controls and procedures designed to ensure that such information is accumulated and communicated to the Company's management, including the CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure. ICFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

In accordance with the requirements of National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings", an evaluation of the effectiveness of DC&P and ICFR was carried out under the supervision of the CEO and CFO at December 31, 2018. This evaluation was based on the framework established in the Internal Control – Integrated Framework (2013) issued in May 2013 by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on this evaluation, the CEO and CFO have concluded that the Company's DC&P and ICFR are effectively designed and operating as intended.

The Company's management, including the CEO and CFO, does not expect that the Company's DC&P and ICFR will prevent or detect all misstatements or instances of fraud. The inherent limitations in all control systems are such that they can provide only reasonable, not absolute, assurance that all control issues, misstatements or instances of fraud, if any, within the Company have been detected.

There have been no changes to the Company's ICFR that occurred during the most recent interim period that has materially affected, or is reasonably likely to materially affect, the Company's ICFR.

Critical Accounting Estimates

This MD&A of the Company's financial condition and results of operations is based on the consolidated financial statements for the year ended December 31, 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:

Impairment

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

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

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

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

Property and equipment

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

Income taxes

Preparation of the 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 consolidated balance sheet as deferred tax assets and liabilities.

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

Stock based compensation

The fair values of stock options, equity settled restricted share units ("RSUs"), and warrants are measured using a Black Scholes option pricing model. Measurement inputs include the common share price on the grant date, the exercise price of the instrument, the expected common share price volatility, the weighted average expected life of the instruments, the expected dividends and the risk-free interest rate. Service and non-market performance conditions are not taken into account in determining fair value.

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

Allowance for doubtful accounts

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

Business Risks

For a comprehensive listing of the Company's business risks please see the most recent Annual Information Form for the year ended December 31, 2018 as filed on SEDAR at www.sedar.com. Certain of the Company's primary business risks as at December 31, 2018 are as follows:

- The Company's business relies on the crude oil and natural gas exploration and production industry which is subject to a number of risks including general economic conditions, fluctuations in demand and supply of crude oil and natural gas production, fluctuations in commodity prices, competition and increases in operating costs. In addition, changes may occur in government regulations, including regulations relating to foreign acquisitions, prices, taxes, royalties, land tenure, allowable production, importing and exporting of crude oil and natural gas and environmental protection for the crude oil and natural gas industry as a whole. Risks impacting the crude oil and natural gas exploration and production industry, including the ability of crude oil and natural gas companies to accumulate capital or variations in their exploration and development budgets, may also affect the Company's business. The exact impact of these risks cannot be accurately predicted.
- If a low commodity price environment persists, the demand for the Company's equipment and services will remain lower than normal and the Company's utilization rates and revenue will continue to be adversely affected during such time. In addition, lower utilization and revenue could result in the Company not being in compliance with certain covenants in its Credit Facilities, which in turn could restrict the Company's ability to access its Credit Facilities, pay distributions and incur additional debt in the future.
- The Company may find it necessary in the future to obtain additional debt or equity to support ongoing operations, to refinance debt, to undertake capital expenditures or to undertake acquisitions or other business combination transactions. There can be no assurance that additional financing will be available when needed or on terms acceptable to the Company.
- The Company's exploration and production customers' facilities and other operations emit greenhouse gases which requires them to comply with legislation in those provinces and states where they operate. Over the past

few years, both Federal and Provincial governments have implemented carbon levies on greenhouse gas emissions. The direct or indirect costs of these new greenhouse gas emission reduction regulations, as well as regulations which may be adopted in these or other jurisdictions in the future, may have a material adverse effect on the Company's business, financial condition and results of operations and cash flows, as well as impacting the Company's customers' operations. See the Company's Annual Information Form for the year ended December 31, 2018 for more detail on this risk.

- In addition to global economic events and uncertainty, the capacity within North America to ship commodities to market introduces uncertainties in levels of activity and pricing for crude oil and natural gas production.
- The Company is vulnerable to market prices. Fixed costs, including costs associated with operations, interest, leases, and labour costs account for a significant portion of the Company's expenses. As a result, reduced productivity resulting from reduced demand, equipment failure, or other factors could significantly affect its financial results.
- Competition among oilfield service companies offering related services is significant. Some competitors are larger and have greater revenue than the Company and overall greater financial resources. The Company's ability to generate revenue depends on its ability to attract and win contracts and to perform services.
- Currently, the Company is focused on providing services in the WCSB as well as certain limited geographic areas in the United States, which may expose the Company to more extreme market fluctuations relating to factors such as weather and general economic conditions which may be more extreme than the broader industry conditions.
- The success of the Company is dependent upon the efforts and abilities of its management team. The loss of any member of the management team could have a material adverse effect upon the business and prospects of the Company.
- Safety is a key factor customers consider when selecting an oilfield service company. A decline in the Company's safety performance could result in reduced demand for the Company's services which could have a material adverse effect on the Company's business and financial results.
- The Company's operations are subject to many hazards inherent in the oilfield service industry, such as blowouts, explosions, damaged or lost drilling, well servicing and oilfield rental equipment or damage or loss from inclement weather, which could result in business interruption, casualty losses, damage or destruction of equipment, suspension of operations, environmental damage or damage to property. This could have a material adverse effect on the Company's business and financial results.
- During the prolonged downturn many oilfield service workers left the industry and, therefore, as activity has increased it has been difficult for the Company to attract and retain field crews. This could have a material adverse effect on the Company's business and financial results.
- The Company's business is subject to the operating risks inherent to the oilfield service industry. On occasion, substantial liabilities to third parties may be incurred. The Company will have the benefit of insurance maintained by it and industry standard contracts, however, it may become liable for damages against which it cannot adequately insure or against which it may elect not to insure because of high costs or other reasons.
- The ability of the Company to make payments, dividends or enter into certain transactions will be subject to the applicable laws and contractual restrictions in the instruments governing its indebtedness, including the Credit Facilities and the Second Lien Facility.
- The oilfield service industry has experienced a high degree of invention and innovation. It is possible that new technology will be developed which will compete with the Company's products and services.
- A portion of the operations of the Company are in the United States which subject the Company to currency fluctuations and different tax and regulatory laws.
- The loss of a significant customer or customers, or any decrease in services provided or prices charged to a significant customer or customers could have a material adverse effect on the Company's business and financial results.
- The Company's business is subject to credit risk primarily from credit exposure to customers, with a concentration of credit risk with customers in the crude oil and natural gas industry.
- The Company relies on various information systems to manage its business. If these systems were compromised as a result of a successful cyber-attack, this could have a material adverse effect on the Company business and financial results.

Non-IFRS Measures

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

Operating Revenue

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

Gross Margin

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

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

	Three months ended December 31		Year ended December 31	
(stated in thousands)	**2018**	**2017**	**2018**	**2017**
Operating Revenue				
Drilling	44,498	45,906	165,684	166,660
Production services	13,283	13,362	50,345	52,456
Less: inter-company eliminations	25	(13)	(211)	(128)
	57,806	**59,255**	**215,818**	**218,988**
Third party charges	5,364	7,260	20,629	19,187
Less: inter-company eliminations	(37)	-	(37)	-
Revenue	**63,133**	**66,515**	**236,410**	**238,175**
Less: operating expenses	(66,675)	(66,933)	(251,378)	(245,352)
Add:				
Depreciation - operating	16,161	16,238	65,097	65,227
Stock based compensation - operating	58	66	406	260
Gross Margin	**12,677**	**15,886**	**50,535**	**58,310**

Adjusted EBITDA

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

Operating Earnings (Loss)

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

The following table provides a reconciliation of net loss under IFRS, as disclosed in the 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 December 31		Year ended December 31	
(stated in thousands)	**2018**	**2017**	**2018**	**2017**
Net loss	**(9,530)**	**(4,974)**	**(41,060)**	**(37,445)**
Add:				
Finance costs	4,603	5,598	19,050	21,950
Income tax recovery	(3,641)	(6,842)	(13,634)	(18,555)
Depreciation - operating	16,161	16,238	65,097	65,227
Depreciation - administrative	270	284	1,084	1,213
EBITDA	**7,863**	**10,304**	**30,537**	**32,390**
Add:				
Stock based compensation - operating	58	66	406	260
Stock based compensation - administrative	96	397	772	1,689
Other items	(101)	(700)	(99)	1,356
Adjusted EBITDA	**7,916**	**10,067**	**31,616**	**35,695**
Subtract:				
Depreciation - operating	(16,161)	(16,238)	(65,097)	(65,227)
Depreciation - administrative	(270)	(284)	(1,084)	(1,213)
Operating Loss	**(8,515)**	**(6,455)**	**(34,565)**	**(30,745)**

Net Debt

Management believes that Net Debt is a useful supplemental measure as it provides an indication of the Company's total debt after incorporating cash and cash equivalents. The closest IFRS measure would be long term debt.

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

(stated in thousands)	**December 31, 2018**	**December 31, 2017**
Long term debt	222,258	265,219
Current portion of long term debt	1,822	475
Less: cash and cash equivalents	(3,960)	(48,825)
Net Debt	**220,120**	**216,869**

Defined Terms:

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

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

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

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

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

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

Service Hours: Defined as well servicing hours completed.

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

Contract Drilling Rig Classifications:

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

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

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

Abbreviations:

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

Forward-Looking Statements and Information

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

In particular, forward-looking information in this MD&A includes, but is not limited to, statements relating to commodity pricing; the future demand for and utilization of the Company's services and equipment; the pricing for the Company's services and equipment; the terms of existing and future drilling contracts in Canada and the US and the revenue resulting therefrom (including the number of Operating Days typically generated from the Company's contracts); the Company's expansion and maintenance capital plans for 2019; the Company's liquidity needs including the ability of current capital resources to cover Western's financial obligations and the 2019 capital budget; the use and availability of the Company's Credit Facilities; pricing for Western's services and impact on Adjusted EBITDA; the Company's ability to maintain certain covenants under its Credit Facilities; the future declaration of dividends; expectations as to the increase in crude oil transportation capacity through pipeline development; expectations as to the benefits of the proposed liquefied natural gas expansion in British Columbia; the future deployment of rigs; the potential impact of changes to environmental laws and regulations and the price on carbon emissions; the expectation of continued investment in the Canadian crude oil and natural gas industry; the development of Alberta and British Columbia resource plays; expectations relating to producer spending and activity levels for oilfield services, 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; the Company's competitive advantage; 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 and the Company's competitive position therein; the ability of the Company's various business segments to access equipment (including spare parts and new technologies); changes in laws or regulations; currency exchange fluctuations; the ability of the Company to attract and retain skilled labour and qualified management; the ability to retain and attract significant customers; the ability to maintain a satisfactory safety record; and general business, economic and market conditions.

Although Western believes that the expectations and assumptions on which such forward-looking statements and information are based on are reasonable, undue reliance should not be placed on the forward-looking statements and information as Western cannot give any assurance that they will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risk that recent improvements in commodity pricing may not continue, and other general industry, economic, market and business conditions. Readers are cautioned that the foregoing list of risks, uncertainties and assumptions are not exhaustive. Additional information on these and other risk factors that could affect Western's operations and financial results are discussed under the heading "Risk Factors" in Western's Annual Information Form 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.