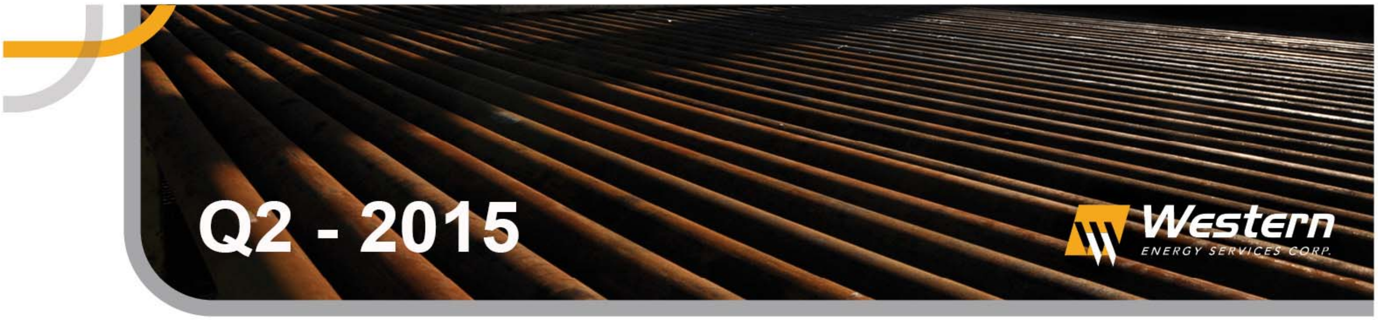

Second Quarter Interim Report

Dated: July 30, 2015

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, 2014 and 2013, the Company's management discussion and analysis ("MD&A") for the year ended December 31, 2014, as well as the condensed consolidated financial statements and notes as at and for the three and six months ended June 30, 2015 and 2014. This MD&A is dated July 30, 2015. All amounts are denominated in Canadian dollars (CDN$) unless otherwise identified.

Financial Highlights	**Three months ended June 30**			**Six months ended June 30**		
(stated in thousands, except share and per share amounts)	**2015**	**2014**	**Change**	**2015**	**2014**	**Change**
Revenue	32,037	81,981	(61%)	137,887	243,397	(43%)
Operating Revenue[1]	30,719	77,352	(60%)	131,677	226,979	(42%)
Gross Margin[1]	10,403	31,206	(67%)	58,294	98,835	(41%)
Gross Margin as a percentage of Operating Revenue	34%	40%	(15%)	44%	44%	-
Adjusted EBITDA[1]	4,255	24,028	(82%)	44,892	83,576	(46%)
Adjusted EBITDA as a percentage of Operating Revenue	14%	31%	(55%)	34%	37%	(8%)
Cash flow from operating activities	41,009	71,912	(43%)	80,346	110,546	(27%)
Capital expenditures	7,688	27,026	(72%)	25,551	46,389	(45%)
Net income (loss)	(12,607)	4,396	(387%)	2,687	29,896	(91%)
-basic net income (loss) per share	(0.17)	0.06	(383%)	0.04	0.40	(90%)
-diluted net income (loss) per share	(0.17)	0.06	(383%)	0.04	0.40	(90%)
Weighted average number of shares						
-basic	74,579,889	74,328,446	-	74,633,065	73,919,531	1%
-diluted	74,591,816	75,733,872	(2%)	74,652,435	75,440,466	(1%)
Outstanding common shares as at period end	74,435,928	74,780,175	-	74,435,928	74,780,175	-
Dividends declared	5,591	5,609	-	11,184	11,147	-
Dividends declared per common share	0.075	0.075	-	0.15	0.15	-
Operating Highlights						
Contract Drilling						
Canadian Operations						
Average contract drilling rig fleet	49	49	-	49	49	-
Operating Revenue per Revenue Day[1]	20,589	26,285	(22%)	25,015	26,368	(5%)
Operating Revenue per Operating Day[1]	22,285	28,632	(22%)	27,570	28,872	(5%)
Drilling rig utilization - Revenue Day[1]	11%	37%	(70%)	33%	63%	(48%)
Drilling rig utilization - Operating Day[1]	10%	34%	(71%)	30%	57%	(47%)
CAODC industry average utilization[1][2]	13%	25%	(48%)	24%	42%	(43%)
United States Operations						
Average contract drilling rig fleet	5	5	-	5	5	-
Operating Revenue per Revenue Day (US$)[1]	27,766 [3]	25,900	7%	28,888 [3]	24,905	16%
Operating Revenue per Operating Day (US$)[1]	32,181 [3]	28,568	13%	33,118 [3]	28,684	15%
Drilling rig utilization - Revenue Day[1]	36%	89%	(60%)	45%	90%	(50%)
Drilling rig utilization - Operating Day[1]	31%	80%	(61%)	39%	78%	(50%)
Production Services						
Average well servicing rig fleet	66	65	2%	66	65	2%
Service rig Operating Revenue per Service Hour[1]	794	800	(1%)	833	814	2%
Service rig utilization[1]	26%	40%	(35%)	34%	51%	(33%)

(1) See "Non-IFRS measures" on page 17 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 and standby revenue from take or pay contracts of US$0.7 million and US$4.5 million for the three and six months ended June 30, 2015 respectively.

Financial Position at (stated in thousands)	June 30, 2015	June 30, 2014	December 31, 2014
Working capital	79,618	71,704	78,336
Property and equipment	840,231	796,997	827,306
Total assets	1,025,776	1,016,112	1,057,118
Long term debt	264,234	263,293	264,165

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 operations in Canada through Western Energy Services Partnership's (the "Partnership") division, Eagle Well Servicing ("Eagle") and oilfield rental equipment services in Canada through the Partnership's division, Aero Rental Services ("Aero"). Financial and operating results for Horizon and Stoneham are included in Western's contract drilling segment, while Eagle and Aero's financial and operating results are included in Western's production services segment. Non-International Financial Reporting Standards ("Non-IFRS") measures are defined on page 17 of this MD&A. Abbreviations for standard industry terms are included on page 18 of this MD&A.

Western currently has a drilling rig fleet of 54 rigs specifically suited for drilling horizontal wells of increased complexity. The average age of the drilling rig fleet is approximately seven years. In total, 96% of Western's fleet are Efficient Long Reach ("ELR") drilling rigs with depth ratings greater than 3,000 meters and all of Western's rigs are capable of drilling conventional and unconventional resource based horizontal wells. Conventional resource plays or formations, such as the Cardium in Canada, typically have higher permeability and tend to be less expensive to develop. As a result of the prior exploitation of conventional resource plays, which due to their increased permeability allows oil and natural gas to flow and be extracted more easily, over time production from these resource plays has declined. Unconventional resource plays or formations, such as the Montney and Duvernay in Canada and the Williston basin in the United States, typically have lower permeability and tend to be more expensive to develop. Horizontal drilling and multi zone hydraulic fracturing have continued to improve the access to and development of these unconventional resource plays.

Western is the sixth largest drilling contractor in Canada with a fleet of 49 rigs operating through Horizon. Of the Canadian fleet, 25 are classified as Cardium rigs, 19 as Montney rigs and 5 as Duvernay rigs. As compared to the Cardium classified rigs, Montney rigs have a larger hookload and capacity, while Duvernay rigs have the largest hookload and capacity. Additionally, Western has five ELR triple drilling rigs deployed in the United States operating through Stoneham. Western is also the sixth largest well servicing company in Canada with a current fleet of 66 rigs operating through Eagle. Western's well servicing rig fleet is one of the newer fleets in the Western Canadian Sedimentary Basin ("WCSB"), with an average age of approximately six years. Western's oilfield rental equipment division, which operates through Aero, provides oilfield rental equipment for frac services, well completions and production work, coil tubing services and drilling.

Crude oil and natural gas prices impact the cash flow of Western's customers, which in turn impacts the demand for Western's services. Overall performance of the Company continued to be affected by the decline in crude oil and natural gas prices for the three and six months ended June 30, 2015. While crude oil prices were strong in the first six months of 2014, they weakened significantly in the last half of 2014 and into the first half of 2015. Partially offsetting the decline in crude oil and natural gas prices for Western's Canadian customers was the strengthening of the US dollar in comparison to the Canadian dollar. The following table summarizes the average oil and natural gas prices, as well as the average foreign exchange rates for the three and six months ended June 30, 2015 and 2014.

	Three months ended June 30			Six months ended June 30		
	2015	2014	Change	2015	2014	Change
Average oil and natural gas prices(1)						
Oil						
West Texas Intermediate (US$/bbl)	57.87	102.99	(44%)	53.22	100.84	(47%)
Western Canadian Select (CDN$/bbl)	56.76	91.34	(38%)	49.96	88.58	(44%)
Natural Gas						
30 day Spot AECO (CDN$/mcf)	2.68	4.70	(43%)	2.71	5.14	(47%)
Average foreign exchange rates						
US dollar to Canadian dollar	1.23	1.09	13%	1.24	1.10	13%

(1) See "Abbreviations" on page 18 of this MD&A.

The significant reduction in commodity prices has resulted in a corresponding decrease in the demand for oilfield services in both Canada and the United States. The Canadian Association of Oilwell Drilling Contractors ("CAODC") reported that, in Canada, the total number of Operating Days in the WCSB decreased approximately 59% and 49% for the three and six months ended June 30, 2015 respectively, as compared to the same periods in the prior year. Similarly, as reported by Baker Hughes Incorporated, the average number of active drilling rigs in the United States decreased approximately 51% and 37% respectively, for the three and six months ended June 30, 2015, as compared to the three and six months ended June 30, 2014. Well servicing hours were also impacted by the decline in demand, as the CAODC reported that Service Hours in the WCSB decreased approximately 33% and 36% respectively, for the three and six months ended June 30, 2015, as compared to the same periods in the prior year.

Key operational results for the three months ended June 30, 2015 include:

- Second quarter Operating Revenues decreased by $46.7 million (or 60%) to $30.7 million in 2015 as compared to $77.4 million in 2014. In the contract drilling segment, Operating Revenues decreased $38.4 million (or 70%) to $16.7 million in the second quarter of 2015 as compared to $55.1 million in the second quarter of 2014. Contract drilling Operating Days decreased approximately 68% in the second quarter of 2015, as compared to the same period in the prior year, due to the decreased commodity price environment, resulting in significant reductions in the capital spending programs of Western's customers. Reduced activity and increased competition resulted in downward pricing pressure which reduced average day rates in the contract drilling segment in Canada by approximately 22%. In the United States, average day rates have increased marginally in the second quarter of 2015, as one of Western's upgraded rigs worked throughout the quarter on a long term contract. In the production services segment, hourly rates decreased marginally by 1% due to increased pricing pressure in all areas, offset by changes in rig mix concentrating on more rigs working in geographic areas that generate higher hourly rates. However, decreased utilization resulted in an $8.9 million decrease in Operating Revenues in the production services segment during the second quarter of 2015, as compared to the second quarter of 2014.
- Second quarter Adjusted EBITDA totalled $4.3 million in 2015 (14% of Operating Revenue), a $19.7 million decrease (or 82%), as compared to $24.0 million in the second quarter of 2014 (31% of Operating Revenue). The year over year decrease in Adjusted EBITDA is due to lower utilization and pricing in both the contract drilling and production services segments.
- Administrative expenses, excluding depreciation and stock based compensation, in the second quarter of 2015 decreased by $1.1 million (or 15%) to $6.1 million (19.9% of Operating Revenue) as compared to $7.2 million in the second quarter of 2014 (9.3% of Operating Revenue). The decrease in administrative expenses is due to lower employee related costs and effective cost control.
- Net income decreased by $17.0 million to a loss of $12.6 million in the second quarter of 2015 (a loss of $0.17 per basic common share) as compared to net income of $4.4 million in the same period in 2014 ($0.06 per basic common share). The decrease is mainly attributed to the $19.7 million decrease in Adjusted EBITDA and an increase in income tax expense of $2.7 million due to the 2% increase in the Alberta corporate tax rate enacted in the quarter, offset by a decrease in depreciation expense of $4.4 million due to lower activity levels, and a $1.0 million decrease in finance and other costs.
- Second quarter capital expenditures of $7.7 million included $5.6 million of expansion capital and $2.1 million of maintenance capital. The majority of the second quarter 2015 capital expenditures relate to the contract drilling segment, which incurred $6.0 million in capital expenditures. These expenditures mainly relate to the completion of Western's 2014 drilling rig build program, which totalled $5.4 million in the period relating to the construction of three drilling rigs. The remaining capital spending in the contract drilling segment related to maintenance capital. Additionally, $1.6 million was incurred in the production services segment relating to maintenance capital and the purchase of additional oilfield rental equipment.
- For the three months ended June 30, 2015, 153,200 common shares for a total cost of $0.9 million were repurchased, cancelled and charged to share capital, or contributed surplus as applicable, under the Company's normal course issuer bid (the "NCIB").

Key operational results for the six months ended June 30, 2015 include:

- Operating Revenues for the six month period ended June 30, 2015 decreased by $95.3 million (or 42%) to $131.7 million as compared to $227.0 million in the same period of the prior year. Included in Operating Revenues in the contract drilling segment for the six month period ended June 30, 2015 is US$4.5 million in shortfall commitment and standby revenue on idle but contracted rigs in the United States. The decrease in Operating Revenue is due to decreased utilization and pricing in the contract drilling segment, coupled with decreased utilization in the production services segment.

- For the first six months of 2015, Adjusted EBITDA decreased by $38.7 million (or 46%) to $44.9 million (34% of Operating Revenue), as compared to $83.6 million (37% of Operating Revenue) in the first six months of 2014. The decrease in Adjusted EBITDA is due to the decrease in activity and pricing across all of Western's divisions, partially offset by Western's cost structure, with approximately 80% of costs being variable, and effective reductions of fixed overhead costs.
- Year to date administrative expenses, excluding depreciation and stock based compensation, decreased by $1.9 million (or 12%) to $13.4 million (10.2% of Operating Revenue), as compared to $15.3 million (6.7% of Operating Revenue) in the same period of the prior year. The decrease in administrative expenses is due to lower employee related costs and effective cost control.
- Net income decreased by $27.2 million to $2.7 million for the six months ended June 30, 2015 ($0.04 per basic common share) as compared to $29.9 million ($0.40 per basic common share) for the same period in 2014. The decrease is mainly attributed to the $38.7 million decrease in Adjusted EBITDA, offset by a decrease in depreciation expense of $8.9 million due to lower activity levels, a decrease of $1.2 million in finance costs due to an increase in capitalized interest and a decrease of $1.6 million on other items such as gains and losses on foreign exchange, asset sales and derivatives.
- Year to date capital expenditures of $25.6 million include $18.7 million of expansion capital and $6.9 million of maintenance capital. The majority of the capital expenditures for the six months ended June 30, 2015 relate to the contract drilling segment, which incurred $21.1 million in capital expenditures. These expenditures mainly relate to the completion of Western's 2014 drilling rig build program, which totalled $16.8 million in the period relating to the construction of three drilling rigs. The remaining capital spending in the contract drilling segment mainly relates to maintenance capital. Additionally, $4.4 million was incurred in the production services segment mainly relating to the construction of one slant well servicing rig and the purchase of additional oilfield rental equipment.
- For the six months ended June 30, 2015, 456,900 common shares for a total cost of $2.5 million were repurchased, cancelled and charged to share capital, or contributed surplus as applicable, under the Company's NCIB. To July 30, 2015, since the NCIB was initiated, 628,000 common shares, for a total cost of $3.4 million, have been repurchased, cancelled and charged to share capital, or contributed surplus, as applicable.

Subsequent Event

On July 30, 2015, the Board of Directors of Western declared a quarterly dividend of $0.075 per share, payable on October 15, 2015 to shareholders of record at the close of business on September 30, 2015. On a prospective basis, the declaration of dividends will be determined on a quarter-by-quarter basis by the Board of Directors.

Outlook

Currently, 9 of Western's 54 drilling rigs (or 17%) are operating under long term take-or-pay contracts providing a base level of future revenue, with 3 of these contracts expected to expire in each of 2015, 2016 and 2017 respectively. These contracts each typically generate 250 Operating Days per year in Canada, as spring breakup restricts activity during the second quarter, while in the United States these contracts each typically generate between 330 to 365 Revenue Days per year.

Western's revised capital budget for 2015 remains unchanged at approximately $42 million, comprised of $23 million of expansion capital and $19 million of maintenance capital. The following table summarizes the 2015 revised capital budget, the capital spending incurred for the six months ended June 30, 2015 and the remaining capital budget expected to be incurred throughout the remainder of 2015:

Capital Expenditures (stated in millions)	**Revised 2015 Budget**	**Six months ended June 30, 2015 Capital Expenditures**	**Capital Budget Remaining**
Expansion	23	(19)	4
Maintenance	19	(7)	12
Total Capital Expenditures	**42**	**(26)**	**16**

Expansion capital relates to the completion of two 5,000m telescopic ELR double drilling rigs, one 6,000m ELR AC triple pad drilling rig and one slant well servicing rig carried forward from the 2014 capital budget. In addition, expansion capital includes $3 million related to the purchase of additional oilfield rental equipment. Spending on maintenance capital is weighted to the second half of 2015, which provides additional flexibility to allow for adjustments if market conditions change. Western believes the 2015 capital budget provides a prudent use of cash resources and ensures that it continues to maintain its balance sheet flexibility allowing for the execution on strategic opportunities as they arise. Western will continue to evaluate and expand its operations in a disciplined manner and make any required adjustments to its capital program when customer demand improves.

The continued pressure on crude oil and natural gas prices has resulted in reductions to the capital spending plans for the majority of Western's customers. In some cases, the capital spending reductions have been significant. The extremely low activity in the second quarter of 2015 has generally resulted in a slower start to the summer drilling programs for many of Western's customers. As a result, active drilling rig counts in both Canada and the United States are currently at, or near, five year lows for third quarter activity. Activity levels throughout the oilfield services industry for the remainder of 2015 are expected to be significantly lower as compared to the second half of 2014, when higher commodity prices and strong customer budgets supported increased utilization and a strong pricing environment across all of Western's business lines. Lower activity and pricing pressure will impact Western's Adjusted EBITDA and cash flow from operating activities in 2015. Western's variable cost structure, under which approximately 80% of operating and administrative costs are variable, and a prudent capital budget will aid in preserving balance sheet strength. At June 30, 2015, Western's Net Debt to trailing 12 month Adjusted EBITDA ratio was 1.3. In addition to $83.6 million in cash and cash equivalents at June 30, 2015, Western has $175 million available on the Company's revolving credit facility (the "Revolving Facility"), which does not mature until December 17, 2018, $20 million available on the Company's operating demand revolving loan (the "Operating Facility"), and no principal repayments due on the $265 million senior unsecured notes (the "Senior Notes") until they mature on January 30, 2019. As such, Western is well positioned to manage the current slowdown in activity and maintain its dividend.

Oilfield service activity will be impacted by the development of resource plays in Alberta and northeast British Columbia including those related to liquefied natural gas projects, increased crude oil transportation capacity through rail and pipeline development and foreign investment into Canada. Currently, the largest challenges facing the oilfield service industry are customer spending constraints as a result of lower commodity prices and the challenge to retain skilled labour. Western's view is that its modern drilling and well servicing rig fleets, strong customer base and solid reputation provide a competitive advantage which will enable the Company to attract and retain skilled labour, continue its growth strategy and maintain its higher than industry average utilization.

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

	Three months ended June 30			Six months ended June 30		
(stated in thousands)	**2015**	**2014**	**Change**	**2015**	**2014**	**Change**
Revenue						
Operating Revenue[1]	16,746	55,148	(70%)	92,353	168,493	(45%)
Third party charges	857	3,132	(73%)	4,362	13,090	(67%)
Total revenue	17,603	58,280	(70%)	96,715	181,583	(47%)
Expenses						
Operating						
Cash operating expenses	11,403	34,929	(67%)	51,903	104,050	(50%)
Depreciation	4,164	8,143	(49%)	14,263	21,789	(35%)
Stock based compensation	63	117	(46%)	178	255	(30%)
Total operating expenses	15,630	43,189	(64%)	66,344	126,094	(47%)
Administrative						
Cash administrative expenses	3,402	4,343	(22%)	7,297	9,070	(20%)
Depreciation	95	56	70%	175	122	43%
Stock based compensation	168	56	200%	270	127	113%
Total administrative expenses	3,665	4,455	(18%)	7,742	9,319	(17%)
Gross Margin[1]	6,200	23,351	(73%)	44,812	77,533	(42%)
Gross Margin as a percentage of Operating Revenue	37%	42%	(12%)	49%	46%	7%
Adjusted EBITDA[1]	2,798	19,008	(85%)	37,515	68,463	(45%)
Adjusted EBITDA as a percentage of Operating Revenue	17%	34%	(50%)	41%	41%	-
Operating Earnings (Loss)[1]	(1,461)	10,809	(114%)	23,077	46,552	(50%)
Capital expenditures	6,047	24,456	(75%)	21,076	41,030	(49%)
Canadian Operations						
Contract drilling rig fleet:						
Average	49	49	-	49	49	-
End of period	49	49	-	49	49	-
Operating Revenue per Revenue Day[1]	20,589	26,285	(22%)	25,015	26,368	(5%)
Operating Revenue per Operating Day[1]	22,285	28,632	(22%)	27,570	28,872	(5%)
Operating Days[1]	464	1,529	(70%)	2,617	5,061	(48%)
Number of meters drilled	110,435	344,117	(68%)	511,066	1,008,470	(49%)
Number of wells drilled	33	86	(62%)	148	315	(53%)
Average Operating Days per well	14.1	17.8	(21%)	17.7	16.1	10%
Drilling rig utilization - Revenue Day[1]	11%	37%	(70%)	33%	63%	(48%)
Drilling rig utilization - Operating Day[1]	10%	34%	(71%)	30%	57%	(47%)
CAODC industry average utilization[1][2]	13%	25%	(48%)	24%	42%	(43%)
United States Operations						
Contract drilling rig fleet:						
Average	5	5	-	5	5	-
End of period	5	5	-	5	5	-
Operating Revenue per Revenue Day (US$)[1]	27,766 [3]	25,900	7%	28,888 [3]	24,905	16%
Operating Revenue per Operating Day (US$)[1]	32,181 [3]	28,568	13%	33,118 [3]	28,684	15%
Operating Days[1]	142	365	(61%)	356	711	(50%)
Number of meters drilled	37,366	79,641	(53%)	98,224	158,291	(38%)
Number of wells drilled	7	15	(53%)	17	29	(41%)
Average Operating Days per well	20.3	24.3	(16%)	20.9	24.6	(15%)
Drilling rig utilization - Revenue Day[1]	36%	89%	(60%)	45%	90%	(50%)
Drilling rig utilization - Operating Day[1]	31%	80%	(61%)	39%	78%	(50%)

(1) See "Non-IFRS measures" on page 17 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 and standby revenue from take or pay contracts of US$0.7 million and US$4.5 million for the three and six months ended June 30, 2015 respectively.

During the second quarter of 2015, Operating Revenues in the contract drilling segment totalled $16.7 million, a $38.4 million decrease (or 70%), as compared to the second quarter of 2014. Included in Operating Revenues in the second quarter of 2015 is US$0.7 million of standby revenue on an idle but contracted rig in the United States. Reduced demand for the Company's contract drilling services in both Canada and the United States, due to the decreased commodity price environment, led to significantly lower year over year activity and has put downward pressure on day rates in Canada and the United States. Average day rates in Canada decreased 22% in the second quarter of 2015, as compared to the second quarter of 2014. However, in the United States, one of Western's upgraded rigs worked throughout the quarter on a long term contract, resulting in an increase in the average day rates during the second quarter.

For the six months ended June 30, 2015, Operating Revenues in the contract drilling segment totalled $92.4 million, a $76.1 million decrease (or 45%), as compared to the six months ended June 30, 2014. Included in Operating Revenues in the first six months of 2015 is US$4.5 million of shortfall commitment and standby revenue on idle but contracted rigs in the United States. Reduced demand for the Company's contract drilling services in both Canada and the United States, due to the decreased commodity price environment, led to significantly lower year over year activity and has put downward pressure on day rates in Canada and the United States. However, changes in the Company's active rig mix, weighted to the deeper rigs in the fleet which command higher day rates, resulted in only a marginal decrease in average day rates in Canada, and resulted in an increase in average day rates in the United States.

During the second quarter of 2015, Adjusted EBITDA in the contract drilling segment decreased by $16.2 million (or 85%) to $2.8 million (17% of the segment's Operating Revenue), as compared to $19.0 million (34% of the segment's Operating Revenue) in the second quarter of 2014, due to the decrease in Operating Days in both Canada and the United States, coupled with the decrease in average day rates in Canada of 22%, partially offset by the increase in average day rates in the United States and effective cost control.

During the six months ended June 30, 2015, Adjusted EBITDA in the contract drilling segment decreased by $31.0 million (or 45%) to $37.5 million (41% of the segment's Operating Revenue), as compared to $68.5 million (41% of the segment's Operating Revenue) in the same period of 2014, mainly due to the decrease in Operating Days in both Canada and the United States, coupled with a marginal decrease in average day rates in Canada. The decrease in activity was partially offset by the increase in average day rates in the United States, the US$4.5 million in shortfall commitment and standby revenue on idle but contracted rigs and effective cost control, which contributed to Adjusted EBITDA as a percentage of Operating Revenue remaining constant. Normalizing for US$4.5 million in shortfall commitment and standby revenue, Adjusted EBITDA as a percentage of the segment's Operating Revenue decreased to 37%, due to decreased activity, partially offset by cost reduction measures.

For the three months ended June 30, 2015, cash administrative expenses, excluding depreciation and stock based compensation, decreased 22% to $3.4 million, compared to $4.3 million for the three months ended June 30, 2014. For the six months ended June 30, 2015, cash administrative expenses, excluding depreciation and stock based compensation, decreased 20% to $7.3 million, compared to $9.1 million in the prior year. The decrease for both the three and six months ended June 30, 2015 is mainly due to lower employee costs and effective cost reduction measures.

Depreciation expense in the contract drilling segment for the quarter ended June 30, 2015 decreased by $3.9 million to $4.3 million, while for the six months ended June 30, 2015 depreciation expense decreased by $7.5 million to $14.4 million. The decrease for both the three and six months ended June 30, 2015 is due to the decrease in Operating Days in the respective periods as compared to the same periods of the prior year.

Capital expenditures totalled $6.0 million in the second quarter of 2015 in the contract drilling segment and include $5.4 million related to expansion capital and $0.6 million related to maintenance capital. For the six months ended June 30, 2015, contract drilling capital expenditures totalled $21.1 million and include $16.8 million related to expansion capital and $4.3 million related to maintenance capital. Of the expansion capital incurred for the three and six months ended June 30, 2015, substantially all relates to the completion of the Company's 2014 rig build program related to the construction of three drilling rigs, all of which are expected to be commissioned during the third quarter of 2015.

Canadian Operations

During the second quarter of 2015, drilling rig utilization - Operating Day in Canada decreased to 10% compared to 34% in the second quarter of 2014. The decrease in utilization is due to reduced demand, resulting in a 70% decrease in the Company's Operating Days to 464 days in the second quarter of 2015, as compared to 1,529 days in the second quarter of 2014. The Company's drilling rig utilization - Operating Day in Canada of 10% in the second quarter of 2015 reflects an approximate 300 basis points ("bps") discount to the CAODC industry average of 13%, as compared to the 900 bps premium realized in the second quarter of 2014. The change relative to the CAODC industry average is due to a number of Western's customers, who typically drill through spring break up, significantly cutting their second quarter drilling programs in 2015, which resulted in the discount to the CAODC industry average.

During the six months ended June 30, 2015, drilling rig utilization - Operating Day in Canada decreased to 30% compared to 57% for the six months ended June 30, 2014. The decrease in utilization is due to reduced demand, resulting in a 48% decrease in the Company's Operating Days to 2,617 days in 2015, as compared to 5,061 days in 2014. The majority of the decrease in Operating Days relates to Western's Cardium rigs which operate in highly competitive conventional resource plays. Operating Days on these drilling rigs decreased by 62% for the six months ended June 30, 2015 as compared to the six months ended June 30, 2014, while Operating Days on Western's Montney and Duvernay rigs, which operate in unconventional resource plays, were impacted to a lesser extent, decreasing by 31%. The Company's drilling rig utilization - Operating Day in Canada of 30% for the six months ended June 30, 2015 reflects an approximate 600 basis points ("bps") premium to the CAODC industry average of 24%, as compared to the 1,500 bps premium realized for the six months ended June 30, 2014. The decrease in the Company's utilization premium from the six months ended June 30, 2014 is partially due to a reduction in the industry rig count from 808 rigs at June 30, 2014 to 768 rigs at June 30, 2015 as competitors continue to decommission older shallower rigs given the current market conditions. From the end of the second quarter of 2014 to the end of the second quarter of 2015, 44 drilling rigs were added to the industry fleet with 84 drilling rigs being removed by decommissioning or movement out of the WCSB, for a net impact of 40 fewer drilling rigs year over year. Of the rigs added year over year, the majority of new additions are higher specification drilling rigs that directly compete with Western's drilling rig fleet, which impacts Western's utilization premium to the industry average. Additionally, the first quarter of 2014 benefited from a strong start up of customer capital programs following a strong fourth quarter of 2013, whereas the first six months of 2015 were impacted by customer capital spending cuts, resulting in an early end to first quarter activity and a delayed start to the summer drilling season. The Company's utilization premium for the six months ended June 30, 2015, as compared to the CAODC industry average, is attributable to the Company's customer base which includes a high proportion of large independent and major exploration and production companies that are more likely to drill through cycles and have a long term focus, coupled with Western's continued investment in its ELR fleet, which enhances the marketability of its rigs.

For the three months ended June 30, 2015, Operating Revenue per Revenue Day in Canada totalled $20,589 compared to $26,285 in the same period of the prior year, a 22% decrease. The decreased commodity price environment and increased competition in the contract drilling industry resulted in downward pricing pressure decreasing day rates on all rig categories in Canada. Third party charges per Revenue Day decreased in the second quarter of 2015 to approximately $1,300 per Revenue Day as compared to approximately $1,800 per Revenue Day in the second quarter of 2014, mainly due to lower fuel prices.

For the six months ended June 30, 2015, Operating Revenue per Revenue Day in Canada totalled $25,015 compared to $26,368 in the same period of the prior year, a 5% decrease. While downward pricing pressure decreased day rates in Canada, Operating Days on the Company's Montney and Duvernay rigs, which command higher day rates, increased as a percentage of the Company's total Operating Days. The increased proportion of Operating Days from these drilling rigs, specifically in the first quarter of 2015, partially offset some of the industry pricing pressure resulting in only a marginal decrease in day rates in Canada for the first six months of 2015. Third party charges per Revenue Day decreased for the six months ended June 30, 2015 to approximately $1,300 per Revenue Day as compared to approximately $2,300 per Revenue Day for the same period in 2014, mainly due to lower fuel prices.

United States Operations

In the United States in the second quarter of 2015, Operating Days decreased by 223 days (or 61%) resulting in drilling rig utilization - Operating Day decreasing to 31% compared to 80% in the same period in the prior year. For the six month period ended June 30, 2015, Operating Days decreased by 355 days (or 50%) resulting in drilling rig utilization - Operating Day decreasing to 39% compared to 78% in the same period in the prior year. The decrease for the three and six month periods ended June 30, 2015 is due to reduced activity resulting from the decreased commodity price environment.

During the second quarter of 2015, Operating Revenues per Revenue Day in the United States increased by 7% to US$27,766, as one of Western's upgraded rigs worked throughout the quarter on a long term contract. The increased day rates and US$0.7 million in standby revenue on an idle but contracted rig, partially offset the decline in utilization in the second quarter of 2015.

For the six months ended June 30, 2015, Operating Revenues per Revenue Day in the United States increased by 16% to US$28,888, as day rates on Western's upgraded rig fleet have improved from the same period of the prior year. Western's upgraded rigs worked a greater percentage of the US fleet's total Operating Days in the first six months of 2015 relative to the first six months of 2014, resulting in the increased average day rates for the six months ended June 30, 2015. The increased day rates and shortfall commitment and standby revenue on idle but contracted rigs of US$4.5 million partially offset the decline in utilization in the first half of 2015.

Production Services

(stated in thousands)	Three months ended June 30 2015	2014	Change	Six months ended June 30 2015	2014	Change
Revenue						
Operating Revenue[1]	14,004	22,946	(39%)	39,577	59,494	(33%)
Third party charges	461	1,497	(69%)	1,848	3,328	(44%)
Total revenue	14,465	24,443	(41%)	41,425	62,822	(34%)
Expenses						
Operating						
Cash operating expenses	10,262	16,588	(38%)	27,943	41,520	(33%)
Depreciation	2,720	3,186	(15%)	5,986	7,420	(19%)
Stock based compensation	129	78	65%	165	162	2%
Total operating expenses	13,111	19,852	(34%)	34,094	49,102	(31%)
Administrative						
Cash administrative expenses	1,560	1,919	(19%)	3,357	3,837	(13%)
Depreciation	104	103	1%	208	206	1%
Stock based compensation	113	64	77%	167	149	12%
Total administrative expenses	1,777	2,086	(15%)	3,732	4,192	(11%)
Gross Margin[1]	4,203	7,855	(46%)	13,482	21,302	(37%)
Gross margin as a percentage of Operating Revenue	30%	34%	(12%)	34%	36%	(6%)
Adjusted EBITDA[1]	2,643	5,936	(55%)	10,125	17,465	(42%)
Adjusted EBITDA as a percentage of Operating Revenue	19%	26%	(27%)	26%	29%	(10%)
Operating Earnings (Loss)[1]	(181)	2,647	(107%)	3,931	9,839	(60%)
Capital expenditures	1,631	2,516	(35%)	4,440	5,357	(17%)
Well servicing rig fleet:						
Average	66	65	2%	66	65	2%
End of period	66	65	2%	66	65	2%
Service rig Operating Revenue per Service Hour[1]	794	800	(1%)	833	814	2%
Service Hours[1]	15,596	23,433	(33%)	40,308	60,242	(33%)
Service rig utilization [1]	26%	40%	(35%)	34%	51%	(33%)

(1) See "Non-IFRS measures" on page 17 of this MD&A.

The Company's production services segment includes Eagle's well servicing fleet, which currently totals 66 rigs, as well as Aero's oilfield rental equipment. During the second quarter of 2015, Operating Revenue decreased by $8.9 million (or 39%) to $14.0 million, compared to $22.9 million in the second quarter of 2014. For the quarter ended June 30, 2015, Eagle's contribution to Operating Revenue in the production services segment decreased by $6.3 million (or 34%) to $12.4 million as compared to $18.7 million in the same period of the prior year, whereas Aero's contribution to Operating Revenue in the production services segment decreased by $2.6 million (or 62%) to $1.6 million, compared to $4.2 million in the second quarter of 2014. Operating Revenue decreased for the six months ended June 30, 2015 by $19.9 million (or 33%) to $39.6 million, compared to $59.5 million in the same period of the prior year. For the six months ended June 30, 2015, Eagle's contribution to Operating Revenue in the production services segment decreased by $15.4 million (or 31%) to $33.6 million as compared to $49.0 million in the same period of the prior year, whereas Aero's contribution to Operating Revenue in the production services segment decreased by $4.5 million (or 43%) to $6.0 million, compared to $10.5 million in the same period of the prior year. The decrease in Operating Revenue for both Eagle and Aero for the three and six months ended June 30, 2015 as compared to the same periods in the prior year is due to reduced customer spending resulting from the decreased commodity price environment, leading to a delayed start to summer activity.

Despite the significant decrease in activity, Eagle continued to gain market share in the first six months of 2015, as the CAODC reported that Eagle worked the third most Service Hours in the WCSB for the three and six months ended June 30, 2015, while comparatively having the sixth largest well servicing rig fleet. Service Hours have decreased by 33% in the second quarter of 2015 to 15,596 (26% utilization) as compared to 23,433 (40% utilization) in the same period of the prior year. Service rig Operating Revenue per Service Hour in the second quarter of 2015 decreased marginally to $794 as compared to $800 in the same period of the prior year. While Eagle has experienced pricing pressure across all operating areas, average hourly rates have held steady year over year due to a higher proportion of work being performed in geographic areas that generate higher hourly rates in the second quarter of 2015, as compared to the second quarter of 2014.

Service Hours have decreased by 33% for the six months ended June 30, 2015 to 40,308 (34% utilization) as compared to 60,242 (51% utilization) in the same period of the prior year. Offsetting the decrease in activity was a 2% increase in service rig Operating Revenue per Service Hour for the first six months of 2015 to $833 compared to $814 in the same period of the prior year. While Eagle has experienced pricing pressure across all operating areas, average hourly rates have improved marginally year over year. The increase is due to a higher proportion of work performed in geographic areas that generate higher hourly rates.

Adjusted EBITDA decreased to $2.6 million (19% of the segment's Operating Revenue) during the second quarter of 2015 from $5.9 million (26% of the segment's Operating Revenue) in the second quarter of 2014. During the six months ended June 30, 2015, adjusted EBITDA decreased to $10.1 million (26% of the segment's Operating Revenue) from $17.5 million (29% of the segment's Operating Revenue) for the six months ended June 30, 2014, mainly due to the decreased commodity price environment impacting the demand for the Company's services.

As a result of lower employee costs and cost reduction initiatives, during the second quarter of 2015, cash administrative expenses, excluding depreciation and stock based compensation, decreased 19% to $1.6 million as compared to $1.9 million in the same period of the prior year. For the same reasons, during the six months ended June 30, 2015, cash administrative expenses, excluding depreciation and stock based compensation, decreased 13% to $3.4 million as compared to $3.8 million in the same period of the prior year.

In the three and six months ended June 30, 2015, depreciation expense decreased by 15% and 18% respectively, to $2.8 million and $6.2 million respectively, mainly due to fewer service rig hours compared to the same periods of the prior year.

During the three months ended June 30, 2015, capital expenditures in the production services segment totalled $1.6 million and mainly related to maintenance capital, and the purchase of additional oilfield rental equipment. During the six months ended June 30, 2015, capital expenditures in the production services segment totalled $4.4 million and mainly related to expansion capital associated with the construction of one slant well servicing rig and the purchase of additional oilfield rental equipment. During the first quarter of 2015, Eagle commissioned the slant well servicing rig previously under construction and now has a fleet of 66 well servicing rigs.

Corporate

	Three months ended June 30			Six months ended June 30		
(stated in thousands)	**2015**	**2014**	**Change**	**2015**	**2014**	**Change**
Administrative						
Cash administrative expenses	1,186	916	29%	2,748	2,352	17%
Depreciation	286	280	2%	531	556	(4%)
Stock based compensation	526	169	211%	1,182	560	111%
Total administrative expenses	1,998	1,365	46%	4,461	3,468	29%
Finance costs	4,763	5,327	(11%)	9,521	10,730	(11%)
Other items	(819)	113	(825%)	(1,413)	602	(335%)
Income taxes						
Current tax (recovery) expense	(2,286)	981	(333%)	(3,771)	3,801	(199%)
Deferred tax expense	6,836	959	613%	14,743	7,201	105%
Total income taxes	4,550	1,940	135%	10,972	11,002	-
Operating loss(1)	(1,472)	(1,196)	(23%)	(3,279)	(2,908)	(13%)
Capital expenditures	10	54	(81%)	35	2	1,650%

(1) See "Non-IFRS measures" on page 17 of this MD&A.

Corporate administrative expenses for the three and six month periods ended June 30, 2015 increased marginally by $0.3 million in each period to $1.2 million and $2.7 million respectively, mainly due to one time employee related costs.

For the three and six month periods ended June 30, 2015, finance costs on a consolidated basis decreased by $0.5 million and $1.2 million respectively, as compared to the same periods in the prior year. The decrease is mainly due to higher capitalized interest in 2015 related to Western's rig build program. The Company had an effective interest rate of 8.4% on its borrowings throughout 2014 and during the first six months of 2015.

Other items for the three and six months ended June 30, 2015 mainly consist of gains on foreign exchange, asset sales and derivatives.

For the three months ended June 30, 2015, income taxes on a consolidated basis totalled $4.6 million and represented an effective tax rate of negative 56.5%, as compared to 30.6% during the three months ended June 30, 2014. For the six months ended June 30, 2015, income taxes on a consolidated basis totalled $11.0 million representing an effective tax rate of 80.3% as compared to 26.9% in the same period of 2014. Income tax expense was impacted for both the three and six months ended June 30, 2015 by the increase in the Alberta corporate tax rate to 12% from 10% previously, which received Royal Assent in the second quarter of 2015, and resulted in an approximate $6.0 million increase to deferred income tax expense in both periods. Additionally, due to earnings before tax being in a loss position in the second quarter of 2015 and earnings before tax being significantly lower for the six months ended June 30, 2015, as compared to the same period in the prior year, adjustments made in calculating tax expense for non deductible items such as stock based compensation, had a greater impact on the effective tax rate during both the three and six months ended June 30, 2015. The effective tax rate for the three and six months ended June 30, 2015 was also impacted by a higher proportion of taxable income earned in the United States which has higher corporate tax rates. The current tax recovery for the three months ended June 30, 2015 of $2.3 million and $3.8 million for the six months ended June 30, 2015 is mainly due to the recognition of tax losses during the respective periods expected to be carried back to prior taxation years. Normalizing for these items, the Company's effective tax rate for the three and six months ended June 30, 2015 is approximately 20.2% and 33.5%, respectively.

Liquidity and Capital Resources

The Company's liquidity needs in the short term and long term can be sourced in several ways including: available cash balances, funds from operations, borrowing against existing credit facilities, new debt instruments, equity issuances and proceeds from the sale of assets. As at June 30, 2015, Western had cash and cash equivalents of $83.6 million, an increase of $20.9 million from December 31, 2014. As a result, Western's consolidated Net Debt balance at June 30, 2015 was $181.7 million, a decrease of $20.9 million as compared to December 31, 2014. During the six months ended June 30, 2015, Western had Adjusted EBITDA of $44.9 million and a positive change in non-cash working capital of $32.3 million mainly due to the collection of prior year receivables, which was partially offset by capital expenditures of $25.6 million, dividend payments of $11.2 million, cash interest payments of $10.3 million, and income tax payments of $8.4 million.

While accounts receivable collections have exceeded operating and capital expenditures in 2015, resulting in a net increase in the Company's cash balances, working capital has remained relatively constant. As at June 30, 2015, Western had a working capital balance of $79.6 million, a $1.3 million increase as compared to December 31, 2014. As at June 30, 2015, the Company has $265.0 million in Senior Notes outstanding, $195.0 million in available credit facilities and is in compliance with all debt covenants. Currently, Western's Net Debt to trailing 12 month Adjusted EBITDA is 1.3 with no scheduled long term debt repayments until January 2019. As such, cash from operations coupled with Western's working capital, including cash balances, and available credit facilities are expected to be sufficient to cover Western's financial obligations including the revised 2015 capital budget.

For the three months ended June 30, 2015, the Company had three customers comprising 12.2%, 11.5% and 10.4% respectively, of the Company's total revenue. The trade receivable balance relating to these customers as at June 30, 2015 represented 8.0%, 4.6% and 3.9% respectively, of the Company's total trade and other receivables. These three customers are publicly traded companies with market capitalizations each in excess of $5 billion at June 30, 2015. One of these previously mentioned customers was also a significant customer for the six months ended June 30, 2015, comprising 11.8% of the Company's total revenue. For the three months ended June 30, 2014, the Company had two significant customers comprising 17.1% and 10.2% respectively, of the Company's total revenue, one of which was also a significant customer for the six months ended June 30, 2014, comprising 13.9% of the Company's total revenue. The Company's significant customers may change quarter to quarter.

Summary of Quarterly Results

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

Three months ended	**Jun 30, 2015**	**Mar 31, 2015**	**Dec 31, 2014**	**Sep 30, 2014**	**Jun 30, 2014**	**Mar 31, 2014**	**Dec 31, 2013**	**Sep 30, 2013**
(stated in thousands, except per share amounts)								
Revenue	32,037	105,850	139,210	125,225	81,981	161,416	129,713	101,389
Operating Revenue(1)	30,719	100,958	129,181	117,960	77,352	149,627	119,831	96,473
Gross Margin(1)	10,403	47,891	57,826	50,570	31,206	67,629	52,980	37,547
Adjusted EBITDA(1)	4,255	40,637	50,419	42,782	24,028	59,548	43,543	30,297
Cash flow from operating activities	41,009	39,337	47,830	22,975	71,912	38,634	36,866	6,667
Net income (loss)	(12,607)	15,294	(8,164)	14,718	4,396	25,500	15,797	7,927
per share - basic	(0.17)	0.20	(0.11)	0.20	0.06	0.35	0.22	0.11
per share - diluted	(0.17)	0.20	(0.11)	0.19	0.06	0.34	0.21	0.11
Total assets	1,025,776	1,049,145	1,057,118	1,040,973	1,016,112	1,019,192	986,792	947,836
Long term debt	264,234	264,207	264,165	263,624	263,293	263,119	262,877	263,050
Dividends declared	5,591	5,593	5,614	5,615	5,609	5,538	5,504	5,502

(1) See "Non-IFRS measures" on page 17 of this MD&A.

Revenues were impacted by lower commodity prices in the first and second quarters of 2015. Prior to the first quarter of 2015, with the exception of lower activity in the second quarter of 2014, due to the seasonal nature of the oilfield service industry in Canada, revenues increased significantly due to the Company's capital spending program and increased activity in both the contract drilling and production services segments throughout 2013 and 2014.

Adjusted EBITDA has followed a similar trend to revenue, steadily increasing after spring breakup in the second quarters through the third and fourth quarters and into the first quarter. Adjusted EBITDA is generally highest in the first quarter when activity is the highest. Adjusted EBITDA was impacted significantly in the first and second quarters of 2015 due to the decreased commodity price environment resulting in customers delaying or cancelling their capital programs. Adjusted EBITDA continuously improved from the third quarter of 2013 through to the first quarter of 2014, while being impacted by spring breakup in Canada in the second quarter of 2014. Adjusted EBITDA was impacted by spring breakup to a much lesser extent in the second quarter of 2014 than in past second quarters, due to favourable weather conditions, increased pad drilling, improved commodity prices, and a weaker Canadian dollar leading to more customers drilling through spring breakup.

Net income has fluctuated throughout the last eight quarters due to the seasonal nature of the oilfield service industry in Canada. Additionally, the Company recorded a net loss in the fourth quarter of 2014 due to impairment losses of $22.7 million on goodwill and $7.2 million on property and equipment.

Total assets of the Company have remained relatively constant throughout the last eight quarters as capital spending has been largely offset by depreciation and the impairment losses on goodwill and property and equipment recorded in the fourth quarter of 2014.

Contractual Obligations

In the normal course of business the Company incurs contractual obligations. The expected maturities of the Company's contractual obligations as at June 30, 2015 are as follows:

(stated in thousands)	2015	2016	2017	2018	2019	Thereafter	Total
Senior Notes	$ -	$ -	$ -	$ -	$ 265,000	$ -	$ 265,000
Senior Notes interest	10,434	20,869	20,869	20,869	10,434	-	83,475
Trade payables and other current liabilities	26,574	-	-	-	-	-	26,574
Dividends payable	5,591	-	-	-	-	-	5,591
Operating leases	2,226	3,600	2,536	2,377	2,329	11,839	24,907
Purchase commitments	4,078	-	-	-	-	-	4,078
Other long term debt	637	876	615	71	-	-	2,199
Total	$ 49,540	$ 25,345	$ 24,020	$ 23,317	$ 277,763	$ 11,839	$ 411,824

There have been no material changes in the contractual obligations detailed above, other than in the normal course of business, during the current interim period.

Outstanding Share Data

	July 30, 2015	June 30, 2015	December 31, 2014
Common shares outstanding	74,288,228	74,435,928	74,866,028
Restricted share units outstanding	294,453	287,727	304,336
Stock options outstanding	4,401,335	4,339,335	5,093,972

Off Balance Sheet Arrangements

As at June 30, 2015, Western had no off balance sheet arrangements in place.

Transactions with Related Parties

During the three and six months ended June 30, 2015, 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 a "financial asset or financial liability at fair value through profit or loss", "available-for-sale financial assets", "held-to-maturity investments", "loans and receivables", or "other financial liabilities".

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 on 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.

Derivatives embedded in other instruments or host contracts are separated from the host contract and accounted for separately when their economic characteristics and risks are not closely related to the host contract. Embedded derivatives are recorded on the balance sheet at their estimated fair value and changes in the fair value are recorded through net income. The asset is recognized in other assets on the balance sheet while a change in the value of the embedded derivative is included in other items within net income.

The Company has the following non-derivative financial assets:

(i) Financial assets at fair value through profit or loss:

Cash and cash equivalents is held for trading within the fair value through profit or loss category. Financial assets at fair value through profit or loss are measured at fair value, and changes therein are recognized in net income.

(ii) Loans and receivables:

Loans and receivables 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, loans and receivables are measured at amortized cost using the effective interest method, less any impairment losses. The Company's trade and other receivables are categorized as loans and receivables.

(iii) Available for sale:

From time to time, the Company may have certain equity investments in publicly traded entities. Investments that have a quoted price in an active market are measured at fair value with changes in fair value recognized in other comprehensive income. When the investment is ultimately sold, any gains or losses are recognized in net income and any unrealized gains or losses previously recognized in other comprehensive income are reversed.

The Company has the following non-derivative financial liabilities:

(i) Other financial liabilities:

Trade and other payables, finance lease obligations, the Senior Notes and credit facilities are classified as "other financial liabilities". Other financial liabilities are recognized initially at fair value net of any directly attributable transaction costs. Other financial liabilities, including the Senior Notes, 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.

(ii) Equity instruments:

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any tax effects.

Credit Risk

The Company's accounts receivable are with customers in the oil and 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 constantly reviews individual customer trade receivables, taking into consideration payment history and the aging of the receivable to monitor collectability.

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.

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 to address short term imbalances. From time-to-time the Company may use forward foreign currency contracts to hedge against these fluctuations.

Liquidity Risk

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

Disclosure Controls and Procedures and Internal Controls Over Financial Reporting

As Western's common shares trade on the Toronto Stock Exchange, per National Instrument 52-109, CERTIFICATION OF DISCLOSURE IN ISSUERS' ANNUAL AND INTERIM FILINGS, the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") of the Company have certified as at June 30, 2015 that they have designed or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") to provide reasonable assurance that: (i) material information relating to the Company, including its consolidated subsidiaries, is made known to the CEO and the CFO by others within those entities, particularly during the periods in which the interim filings of the Company are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The CEO and CFO do not expect that the DC&P will prevent or detect all errors, misstatements and fraud but are designed to provide reasonable assurance of achieving their objectives. A control system, no matter how well designed or operated, can only provide reasonable, but not absolute, assurance that the objectives of the control system are met. In addition to DC&P, the CEO and CFO have designed internal controls over financial reporting, or caused them to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with International Financial Reporting Standards ("IFRS").

During the three months ended June 30, 2015, there were no changes in internal control over financial reporting that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Critical Accounting Estimates

This MD&A of the Company's financial condition and results of operations is based on the condensed consolidated financial statements for the three and six months ended June 30, 2015, which were prepared in accordance with IFRS. The presentation of these financial statements in conformity with IFRS requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of provisions at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. 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 key accounting estimates relate to business combinations, impairment, depreciation, current and deferred taxes and the determination of the fair value of share based payments.

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

Business Combinations

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

Impairment

The Company assesses impairment at each reporting date by evaluating conditions specific to the organization that may lead to impairment of assets. Where an impairment indicator exists, or annually in the case of goodwill, the recoverable amount of the asset or cash generating unit is determined. The application of judgement is required in determining if an impairment test is required. If indicators conclude that the asset is no longer impaired, the Company will reverse impairment losses on assets. Impairment losses on goodwill are not reversed. Similar to determining if an impairment exists, judgment is required in assessing if a reversal of an impairment loss is required. Value-in-use and fair value less cost to sell calculations performed in assessing the recoverable amounts incorporate a number of key estimates. During the three and six months ended June 30, 2015, there were no impairment losses or reversals of previous impairment losses.

Depreciation

The Company's property and equipment is depreciated based upon estimates of useful lives and salvage values. These estimates are based on industry practice and the Company's own experience and may change as more experience is gained, market conditions shift or new technological advancements are made.

The componentization of the Company's property and equipment, specifically drilling rig equipment and well servicing rig equipment, is based on management's judgment as to which components constitute a significant cost in relation to the entire item. The componentization process also requires management's judgement in assessing whether individual components have similar consumption patterns and useful lives.

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 tax assets. To the extent that such recovery is not probable, recognized deferred tax assets must be reduced to the recoverable amount. Judgement is required in determining the provision for income taxes and recognition of deferred tax assets and liabilities. Management must also exercise judgement 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.

Share based payments

Stock based compensation expense associated with stock options and equity settled restricted share units granted is based on various assumptions, using the Black-Scholes option pricing model to calculate an estimate of fair value. The inputs into the model include interest rates, expected life, expected volatility, expected forfeitures, expected dividends and share prices and these inputs affect the estimated fair value calculated. Determining the estimated expected life, volatility, forfeitures and expected dividends requires management's judgement.

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, 2014 as filed on SEDAR at www.sedar.com. The Company's primary business risks as at June 30, 2015 are as follows:

- The Company's business relies on the oil and gas exploration and production industry which is subject to a number of risks including general economic conditions, fluctuations in demand and supply of production components, 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 oil and natural gas and environmental protection for the oil and gas industry as a whole. Risks impacting the oil and gas exploration and production industry, including the ability of oil and 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.
- 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 oil and natural gas production.
- The Company is vulnerable to market prices. Fixed costs, including costs associated with operations, 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 related oilfield service companies is significant. Some competitors are larger and have greater revenues than the Company and overall greater financial resources. The Company's ability to generate revenues 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 geographic areas in the United States, which may expose the Company to more extreme market fluctuations relating to items 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.
- 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 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.

Non-IFRS Measures

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

Operating Revenue

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

Gross Margin

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

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

	Three months ended June 30		**Six months ended June 30**	
(stated in thousands)	**2015**	**2014**	**2015**	**2014**
Operating Revenue				
Drilling	16,746	55,148	92,353	168,493
Production services	14,004	22,946	39,577	59,494
Less: inter-company eliminations	(31)	(742)	(253)	(1,008)
	30,719	**77,352**	**131,677**	**226,979**
Third party charges	1,318	4,629	6,210	16,418
Revenue	**32,037**	**81,981**	**137,887**	**243,397**
Less: operating expenses	(28,710)	(62,299)	(100,185)	(174,188)
Add:				
Depreciation - operating	6,884	11,329	20,249	29,209
Stock based compensation - operating	192	195	343	417
Gross Margin	**10,403**	**31,206**	**58,294**	**98,835**

Adjusted EBITDA

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

Operating Earnings

Management believes that in addition to net income, Operating Earnings is a useful supplemental measure as it provides an indication of the results generated by the Company's principal operating activities similar to Adjusted EBITDA but also factors in the depreciation expense incurred in the period.

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

	Three months ended June 30		Six months ended June 30	
(stated in thousands)	**2015**	**2014**	**2015**	**2014**
Net income (loss)	(12,607)	4,396	2,687	29,896
Add:				
Finance costs	4,763	5,327	9,521	10,730
Income taxes	4,550	1,940	10,972	11,002
Depreciation - operating	6,884	11,329	20,249	29,209
Depreciation - administrative	485	439	914	884
EBITDA	4,075	23,431	44,343	81,721
Add:				
Stock based compensation - operating	192	195	343	417
Stock based compensation - administrative	807	289	1,619	836
Other items	(819)	113	(1,413)	602
Adjusted EBITDA	4,255	24,028	44,892	83,576
Subtract:				
Depreciation - operating	(6,884)	(11,329)	(20,249)	(29,209)
Depreciation - administrative	(485)	(439)	(914)	(884)
Operating Earnings (Loss)	(3,114)	12,260	23,729	53,483

Net Debt

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

(stated in thousands)	**June 30, 2015**	**December 31, 2014**
Long term debt	264,234	264,165
Current portion of long term debt	1,004	1,062
Less cash and cash equivalents	(83,572)	(62,662)
Net Debt	**181,666**	**202,565**

Drilling rig utilization - Operating Day: Calculated based on Operating Days divided by total available days.

Drilling rig utilization - Revenue Day: Calculated based on Revenue Days divided by total available days.

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

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

Service Hours: Defined as actual 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.

Abbreviations:

- Barrels ("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");
- International Financial Reporting Standards ("IFRS");
- Thousand cubic feet ("mcf");
- West Texas Intermediate ("WTI");
- Western Canadian Sedimentary Basin ("WCSB"); and
- Western Canadian Select ("WCS").

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 such statements and disclosures, other than those of historical fact, which address activities, events, outcomes, results or developments that Western anticipates or expects may, or will occur in the future (in whole or part) should be considered forward-looking information. In some cases forward-looking information can be identified by terms such as “forecast”, “future,” “may”, “will”, “expect”, “anticipate,”, “believe”, “potential”, “enable”, “plan”, “continue”, “contemplate”, “pro forma”, or other comparable terminology.

In particular, forward-looking information in this MD&A includes, but is not limited to, statements relating to future declaration of dividends; the future demand for the Company’s services and equipment; the terms of existing and future drilling contracts in Canada and the US and the revenues resulting therefrom (including the number of Operating Days typically generated from the Company’s contracts); the Company’s expansion and maintenance capital plans for 2015, including the ability of current capital resources to cover Western’s financial obligations and the 2015 capital budget; the Company’s expected sources of funding to support such capital plans and the Company’s ability to adjust capital spending if in the second half of 2015 market conditions continue to change; expectations as to the increase in crude oil transportation capacity through rail and pipeline development; expectations as to the necessary approvals for liquefied natural gas projects being obtained; the expectation of continued foreign investment into the Canadian oilfield industry; the expectation that producer spending constraints will continue to be a large challenge facing the Company in 2015; and forward-looking statements under the heading “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; fluctuations in the price and demand for oil and natural gas; the current low levels of, and pressures on, commodity pricing; the continued business relationship between the Company and its significant customers; general economic and financial market conditions; the development of liquefied natural gas projects, crude oil transport and pipeline approval and development; the Company’s ability to finance its operations; the effects of seasonal and weather conditions on operations and facilities; the competitive environment to which the various business segments are, or may be, exposed in all aspects of their business; the ability of the Company’s various business segments to access equipment (including spare parts and new technologies); changes in laws or regulations; currency exchange fluctuations; the ability of the Company to attract and retain skilled labour and qualified management; the ability to retain and attract significant customers; and other unforeseen conditions which could impact the use of services supplied by Western including Western’s ability to respond to such 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 the demand for oilfield services will not improve for the remainder of 2015 and that commodity prices will remain low, and other general industry, economic, market and business conditions. Readers are cautioned that the foregoing list of risks, uncertainties and assumptions are not exhaustive. Additional information on these and other risk factors that could affect Western’s operations and financial results are included in Western’s annual information form which may be accessed through the SEDAR website at www.sedar.com. The forward-looking statements and information contained in this MD&A are made as of the date hereof and Western does not undertake any obligation to update publicly or revise any forward-looking statements and information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

Additional data

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