
## 2016 Management Discussion & Analysis — Date: February 22, 2017

*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, 2016 and 2015. This Management Discussion and Analysis ("MD&A") is dated February 22, 2017. 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)** | **2016** | **2015** | **2016** | **2015** | **2014** |
| Revenue | 45,126 | 42,678 | 124,438 | 227,524 | 507,832 |
| Operating Revenue (1) | 41,649 | 40,458 | 116,907 | 216,485 | 474,120 |
| Gross Margin (1) | 8,507 | 13,372 | 25,762 | 85,951 | 207,231 |
| Gross Margin as a percentage of Operating Revenue | 20% | 33% | 22% | 40% | 44% |
| Adjusted EBITDA (1) | 3,506 | 7,573 | 5,775 | 60,545 | 176,777 |
| Adjusted EBITDA as a percentage of Operating Revenue | 8% | 19% | 5% | 28% | 37% |
| Cash flow from operating activities | (1,327) | 11,139 | 16,631 | 90,955 | 181,351 |
| Capital expenditures | 2,724 | 3,259 | 4,719 | 33,562 | 108,604 |
| Net income (loss) | (14,509) | (55,010) | (61,973) | (129,139) | 36,450 |
| -basic net income (loss) per share | (0.20) | (0.75) | (0.84) | (1.74) | 0.49 |
| -diluted net income (loss) per share | (0.20) | (0.75) | (0.84) | (1.74) | 0.48 |
| Weighted average number of shares | | | | | |
| -basic | 73,795,896 | 73,655,198 | 73,703,437 | 74,238,320 | 74,396,701 |
| -diluted | 73,795,896 | 73,655,198 | 73,703,437 | 74,238,320 | 75,427,149 |
| Outstanding common shares as at period end | 73,795,944 | 73,646,292 | 73,795,944 | 73,646,292 | 74,866,028 |
| Dividends declared | - | 3,682 | - | 20,392 | 22,376 |
| Dividends declared per common share | - | 0.05 | - | 0.275 | 0.30 |
| **Operating Highlights (1)** | | | | | |
| **Contract Drilling** | | | | | |
| *Canadian Operations* | | | | | |
| Average active rig count | 16.2 | 11.4 | 10.0 | 14.3 | 31.5 |
| Operating Revenue per Revenue Day | 16,657 | 22,038 | 16,984 (3) | 23,458 | 26,178 |
| Operating Revenue per Operating Day | 18,811 | 24,228 | 19,058 (3) | 25,821 | 28,699 |
| Drilling rig utilization - Revenue Days | 32% | 22% | 20% | 29% | 64% |
| Drilling rig utilization - Operating Days | 28% | 20% | 17% | 26% | 58% |
| CAODC industry average utilization (2) | 25% | 20% | 17% | 23% | 44% |
| *United States Operations* | | | | | |
| Average active rig count | 1.7 | 1.0 | 1.4 | 1.6 | 4.7 |
| Operating Revenue per Revenue Day (US$) | 20,197 | 31,350 | 21,805 | 29,483 (4) | 26,124 |
| Operating Revenue per Operating Day (US$) | 23,440 | 34,217 | 25,166 | 33,166 (4) | 29,680 |
| Drilling rig utilization - Revenue Days | 34% | 20% | 28% | 32% | 94% |
| Drilling rig utilization - Operating Days | 29% | 18% | 24% | 29% | 83% |
| **Production Services** | | | | | |
| Average active rig count | 17.6 | 16.7 | 12.9 | 19.5 | 35.0 |
| Service rig Operating Revenue per Service Hour | 638 | 703 | 643 | 779 | 817 |
| Service rig utilization | 27% | 25% | 20% | 30% | 54% |

(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 $1.8 million for the year ended December 31, 2016.

(4) Excludes shortfall commitment and standby revenue from take or pay contracts of US$4.5 million for the year ended December 31, 2015.

| Financial Position at (stated in thousands) | December 31, 2016 | December 31, 2015 | December 31, 2014 |
|---|---|---|---|
| Working capital | 51,118 | 70,679 | 78,336 |
| Property and equipment | 708,567 | 773,647 | 827,306 |
| Total assets | 793,525 | 876,608 | 1,057,118 |
| Long term debt | 264,070 | 264,155 | 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"). On December 28, 2015, Western wound up its partnership, Western Energy Services Partnership (the "Partnership"), and rolled all of the Partnership's assets into IROC Drilling and Production Services Corp., which then changed its name to Western Production Services Corp. ("Western Production Services"). As a result, Western now provides well servicing operations in Canada through Western Production Services' division, Eagle Well Servicing ("Eagle") and oilfield rental equipment services in Canada through Western Production Services' 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 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 56 rigs specifically suited for drilling horizontal wells of increased complexity. Western is currently the fifth largest drilling contractor in Canada, based on the Canadian Association of Oilwell Drilling Contractors ("CAODC") registered rigs, with a fleet of 51 rigs operating through Horizon. Of the Canadian fleet, 24 are classified as Cardium class rigs, 19 as Montney class rigs and eight as Duvernay class rigs. As compared to the Cardium classified 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 five Duvernay class triple drilling rigs deployed in the United States operating through Stoneham. Western is also the third largest well servicing company in Canada, based on CAODC registered rigs, 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. While commodity prices improved in the fourth quarter of 2016, they were still well below previous highs and overall performance of the Company throughout 2016 was impacted by the continued low crude oil and natural gas price environment. West Texas Intermediate ("WTI") on average improved in the fourth quarter of 2016 as compared to the third quarter of 2016, increasing by 10%, and was 17% higher compared to the same period in the prior year. However, for the year ended December 31, 2016, WTI on average was 11% lower than 2015. Canadian natural gas prices, such as AECO, improved quarter over quarter, increasing on average by 31% from the third quarter of 2016 to the fourth quarter of 2016. For the three months ended December 31, 2016, AECO increased on average by 25% as compared to the same period in the prior year, however remained 20% lower for the year ended December 31, 2016, as compared to 2015. 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, 2016 and 2015 and for the years ended December 31, 2016 and 2015.

| | Three months ended December 31 | | | Year ended December 31 | | |
|---|---|---|---|---|---|---|
| | 2016 | 2015 | Change | 2016 | 2015 | Change |
| **Average crude oil and natural gas prices**(1)(2) | | | | | | |
| **Crude Oil** | | | | | | |
| West Texas Intermediate (US$/bbl) | 49.16 | 42.18 | 17% | 43.37 | 48.80 | (11%) |
| Western Canadian Select (CDN$/bbl) | 45.84 | 36.86 | 24% | 39.27 | 44.83 | (12%) |
| **Natural Gas** | | | | | | |
| 30 day Spot AECO (CDN$/mcf) | 3.11 | 2.48 | 25% | 2.18 | 2.71 | (20%) |
| **Average foreign exchange rates**(2) | | | | | | |
| US dollar to Canadian dollar | 1.33 | 1.34 | (1%) | 1.32 | 1.28 | 3% |

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

(2) Source: Bloomberg

The significant reduction in commodity prices has led to a corresponding decrease in the demand for oilfield services in both Canada and the United States. The CAODC reported that for drilling in Canada, the total number of Operating Days in the Western Canadian Sedimentary Basin ("WCSB") decreased approximately 31% in 2016, as compared to 2015. Similarly, as reported by Baker Hughes Incorporated, the number of active drilling rigs in the United States decreased approximately 51% in 2016, as compared to 2015.

Operational results for the three months ended December 31, 2016 include:

- Operating Revenue for the three months ended December 31, 2016 continued to be impacted by low commodity prices, which are still well below previous highs. Fourth quarter Operating Revenue increased by $1.2 million (or 3%) to $41.6 million in 2016 as compared to $40.4 million in 2015. In the contract drilling segment, Operating Revenue totalled $29.0 million in the fourth quarter of 2016 as compared to $27.0 million in the fourth quarter of 2015, an increase of 7%; while in the production services segment, Operating Revenue totalled $12.7 million for the three months ended December 31, 2016 as compared to $13.5 million in the fourth quarter of 2015, a decrease of 6%. Commodity prices began to recover in the fourth quarter of 2016, which combined with built up demand due to weather related delays in the third quarter of 2016, resulted in higher industry activity. However, higher utilization in the fourth quarter, offset by continued pricing pressure, impacted Operating Revenue in the contract drilling and production services segments as described below:
    - Drilling rig utilization – Operating Days (or "Drilling Rig Utilization") in Canada was 28% in the fourth quarter of 2016 compared to 20% in the fourth quarter of 2015, reflecting an 800 basis points ("bps") increase and the highest Drilling Rig Utilization experienced by the Company since the first quarter of 2015. Fourth quarter 2016 Drilling Rig Utilization represented a premium of 300 bps to the CAODC industry average of 25%, whereas in the fourth quarter of 2015, Drilling Rig Utilization of 20% was the same as the industry average. The increase in the Company's utilization premium from 2015 is attributable to the efforts by the Company's marketing group to reposition the Company's rigs for existing and new customers. Despite increased activity, the highly competitive environment and commodity prices still well below previous highs, resulted in downward pricing pressure on all drilling rig classes, which reduced Operating Revenue per Revenue Day in the contract drilling segment in Canada by 24%, as compared to the fourth quarter of 2015;
    - In the United States, the Company had two drilling rigs operating during the quarter, one of which was working on a long term contract, resulting in Drilling Rig Utilization of 29% in the fourth quarter of 2016, as compared to 18% in the same period of the prior year. Operating Revenue per Revenue Day in the United States decreased by 35% in the fourth quarter of 2016 due to renegotiating the day rate, as a result of extending the term on the long term contract, coupled with pricing pressure on spot market rates; and
    - Well servicing utilization of 27% in the fourth quarter of 2016 compared to 25% in the same period of the prior year. Improvements in commodity prices, and built up demand due to weather related delays in the third quarter of 2016, helped improve activity quarter over quarter. However, pricing pressure in all areas continued and resulted in a 9% decrease in well servicing hourly rates, which led to a $0.5 million (or 5%) decrease in well servicing Operating Revenue in the period.
- Fourth quarter Adjusted EBITDA decreased by $4.1 million to $3.5 million in 2016 as compared to $7.6 million in the fourth quarter of 2015. The year over year change in Adjusted EBITDA is due to lower pricing in both the contract drilling and production services segments, offset partially by cost reduction measures, including a reduced headcount year over year, wage reductions to all employees and other cost control measures.
- Administrative expenses, excluding depreciation and stock based compensation, in the fourth quarter of 2016 decreased by $0.8 million (or 14%) to $5.0 million as compared to $5.8 million in the fourth quarter of 2015. The decrease in administrative expenses is due to a reduced employee headcount, a 10% rollback to all salaried employee wages and directors' fees implemented in the first quarter of 2016, as well as additional cost control measures.
- The Company incurred a net loss of $14.5 million in the fourth quarter of 2016 (a loss of $0.20 per basic common share) as compared to a net loss of $55.0 million in the same period in 2015 (a loss of $0.75 per basic common share). The change in the fourth quarter net loss in 2016, relative to the fourth quarter of 2015, can be attributed to the following:
    - Prior year impairment losses on property and equipment of $41.9 million and losses on asset decommissioning of $26.6 million recorded in the fourth quarter of 2015.

  Offsetting the above mentioned items are the following:
    - A $16.1 million decrease in income tax recovery due to the prior year impairment losses on property and equipment and losses on asset decommissioning;

- An increase of $7.9 million in depreciation expense due to the Company changing from unit of production to straight line depreciation for drilling and well servicing rigs effective April 1, 2016; and
- A $4.1 million decrease in Adjusted EBITDA due to lower pricing in both the contract drilling and production services segments.

- Fourth quarter 2016 capital expenditures of $2.7 million included $2.1 million of expansion capital and $0.6 million of maintenance capital. In total, capital spending in the fourth quarter of 2016 decreased by 18% from the $3.3 million incurred in the fourth quarter of 2015, as the Company deployed strategic expansion capital and incurred only necessary maintenance capital to preserve cash during the current slowdown in oilfield service activity.

Operational results for the year ended December 31, 2016 include:

- Operating Revenue in 2016 decreased by $99.6 million (or 46%) to $116.9 million, as compared to $216.5 million in the prior year. In the contract drilling segment, Operating Revenue totalled $78.9 million in 2016 compared to $150.2 million in the prior year; while in the production services segment, Operating Revenue totalled $38.1 million in 2016 compared to $66.6 million in the prior year. Operating Revenue in the contract drilling and production services segments for the year ended December 31, 2016 continued to be impacted by low commodity prices which resulted in decreased utilization and pricing as described below:
  - Drilling Rig Utilization in Canada of 17% for the year ended December 31, 2016, compared to 26% for the prior year, reflects a 35% decrease. Drilling Rig Utilization in 2016 was on par with the CAODC industry average of 17%, as compared to the 300 bps premium to the CAODC industry average realized in 2015. The change in the Company's utilization relative to the CAODC industry average is partially due to a number of Western's customers who typically have substantial drilling programs, significantly cutting their capital spending, particularly in the first three quarters of 2016. Additionally, changes in the industry rig mix, as competitors continue to decommission older and less competitive rigs in the WCSB, and add rigs that directly compete with Western's drilling rig fleet, impacts Western's relative utilization as compared to the CAODC industry average. Lower activity and increased competition resulted in downward pricing pressure on all drilling rig classes, which reduced Operating Revenue per Revenue Day in the contract drilling segment in Canada by 28% in 2016, as compared to 2015;
  - In the United States, Drilling Rig Utilization of 24% for the year ended December 31, 2016, compared to 29% in the prior year. Operating Revenue per Revenue Day in the United States decreased by 26% in 2016 due to renegotiating the day rate as a result of extending the term on a long term contract, coupled with pricing pressure on spot market rates; and
  - Well servicing utilization of 20% for the year ended December 31, 2016 compared to 30% in the prior year. Reduced activity as well as a 17% reduction in well servicing hourly rates, due to pricing pressure in all areas, resulted in a $25.1 million (or 45%) decrease in well servicing Operating Revenue in 2016.
- Adjusted EBITDA decreased by $54.7 million to $5.8 million in 2016, as compared to $60.5 million in 2015. The year over year decrease in Adjusted EBITDA is due to lower utilization and pricing in both the contract drilling and production services segments, offset by cost reduction measures, including a reduced headcount, wage reductions to all employees and other cost control measures.
- Administrative expenses in 2016, excluding depreciation and stock based compensation, decreased by $5.4 million (or 21%) to $20.0 million as compared to $25.4 million in 2015. The decrease in administrative expenses is due to a reduced employee headcount, a 10% rollback to all salaried employee wages and directors' fees implemented in the first quarter of 2016, coupled with additional cost control measures.
- As a result of the Company's review of estimated useful lives and methodology for depreciating its drilling and well service rig fleet and related equipment, effective April 1, 2016, Western changed the method for depreciating its drilling and well service rigs and related equipment from unit of production to straight line and changed certain estimates related to useful lives and salvage values. The change in depreciation methodology reflects the technological developments within the industry. The Company expects that straight line depreciation will better reflect the future economic benefit related to these assets, which are expected to depreciate over time instead of on a unit of production basis. Additionally, the change will result in idle or underutilized assets being depreciated more quickly in periods of low activity, better reflecting the cyclical nature of the oilfield service industry. These adjustments were applied prospectively and resulted in an increase of approximately $6.8 million and $28.1 million respectively, of additional depreciation expense for the three and twelve months ended December 31, 2016 over what would have been expensed had the previous assumptions using the unit of production methodology continued to be used in the periods.

- During the second quarter of 2016, the Company decommissioned one of its Cardium class drilling rigs, resulting in a loss on asset decommissioning of $5.2 million, and as a result at December 31, 2016 Horizon had a fleet of 51 drilling rigs.
- The Company incurred a net loss of $62.0 million for the year ended December 31, 2016 (a loss of $0.84 per basic common share) as compared to a net loss of $129.1 million for the year ended December 31, 2015 (a loss of $1.74 per basic common share). The change in net loss in 2016 can be attributed to the following:
  - A prior year goodwill impairment loss of $71.3 million recorded in the third quarter of 2015;
  - Prior year impairment losses on property and equipment of $41.9 million and losses on asset decommissioning of $26.6 million recorded in the fourth quarter of 2015, partially offset by losses on asset decommissioning of $5.2 million in 2016; and
  - A $9.5 million decrease in income tax expense due to lower taxable income for the year ended December 31, 2016, along with the impact of the Alberta corporate tax rate increase in 2015, which increased income tax expense in the prior period by approximately $6.0 million.

  Offsetting the above mentioned items are the following:
  - A $54.7 million decrease in Adjusted EBITDA due to lower utilization and pricing in both the contract drilling and production services segments;
  - An increase of $20.0 million in depreciation expense due to the Company changing from unit of production to straight line depreciation for drilling and well servicing rigs in the second quarter of 2016; and
  - A $2.1 million increase in finance costs, due to lower capitalized interest as a result of the completion of the 2014 rig build program in the prior year.
- Year to date capital expenditures of $4.7 million included $3.0 million of expansion capital and $1.7 million of maintenance capital. In total, capital spending for 2016 decreased by 86% from the $33.6 million incurred in 2015, as the Company deployed strategic expansion capital and incurred only necessary maintenance capital to preserve cash during the current slowdown in oilfield service activity.
- On April 27, 2016, the Company amended the covenants and elected to reduce its syndicated revolving credit facility (the "Revolving Facility") from $175.0 million to $40.0 million and reduced its previously uncommitted operating demand revolving loan of $20.0 million to a committed operating line (the "Operating Facility") totalling $10.0 million. Western's decision to reduce its Revolving and Operating Facilities (the "Credit Facilities") is estimated to save the Company $1.5 million in standby fees annually. On July 25, 2016, the Company added a lender to its syndicated Revolving Facility and increased the amount available by $10.0 million to $50.0 million, from $40.0 million previously.

**Outlook**

Currently, 34 of Western's drilling rigs are operating and four of Western's 56 drilling rigs (or 7%) are under long term take or pay contracts, with two of these contracts expected to expire in 2017 and two expected to expire in 2018. These contracts each typically generate between 250 and 350 Revenue Days per year.

Western's capital budget for 2017 is expected to total $13 million, with $2 million allocated for expansion capital and $11 million for maintenance capital. Western believes the 2017 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 any required adjustments to its capital program as customer demand changes. The following table summarizes the capital spending incurred in 2016 and the total 2017 capital budget:

| Capital Expenditures (stated in millions) | Revised 2016 Budget Announced February 25, 2016 | Incremental Approved Capital Expenditures | Capital Expenditures Year Ended December 31, 2016 | Cancellations 2016 | Carry Forward Capital Spending 2017 | Budgeted Capital Expenditures Year Ended December 31, 2017 | Total 2017 Budget |
|---|---|---|---|---|---|---|---|
| Expansion | 2 | 2 | (3) | - | 1 | 1 | 2 |
| Maintenance | 5 | 1 | (2) | (3) | 1 | 10 | 11 |
| **Total Capital Expenditures** | **7** | **3** | **(5)** | **(3)** | **2** | **11** | **13** |

Since hitting 10 year lows in the first quarter of 2016, commodity prices, while remaining well below previous highs, have improved significantly, particularly during the fourth quarter of 2016. As such, North American drilling rig counts have begun to recover and the Company is expecting increased year over year activity levels in 2017. However, improved pricing for the Company's services is expected to lag the recovery in activity. Improving gross margin is a priority for the Company, as the worst of the downturn in crude oil and natural gas prices appears to have past. Low prices for Western's services will continue to impact Adjusted EBITDA and cash flow from operating activities in the near term. However, Western's variable cost structure and a prudent capital budget will aid in preserving balance sheet strength. In addition to $44.6 million in cash and cash equivalents at December 31, 2016, Western has $60.0 million undrawn on the Company's Credit Facilities, which do not mature until December 17, 2018 and no principal repayments due on the Senior Notes until they mature on January 30, 2019.

Oilfield service activity in Canada will be impacted by the development of resource plays in Alberta and northeast British Columbia including those related to increased crude oil transportation capacity through pipeline development, increased environmental regulations including the implementation of a carbon tax in Alberta, 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 increasing challenge of staffing field crews, particularly in the well servicing division. Western's view is 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 slowdown in oilfield service activity.

## 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)** | **2016** | **2015** | **2016** | **2015** |
| Revenue | | | | |
| Operating Revenue[1] | 28,965 | 26,978 | 78,887 | 150,252 |
| Third party charges | 2,762 | 1,414 | 5,167 | 7,627 |
| Total revenue | 31,727 | 28,392 | 84,054 | 157,879 |
| Expenses | | | | |
| Operating | | | | |
| Cash operating expenses | 26,382 | 18,975 | 66,010 | 93,120 |
| Depreciation | 13,113 | 5,871 | 45,324 | 26,340 |
| Stock based compensation | 83 | 93 | 287 | 391 |
| Total operating expenses | 39,578 | 24,939 | 111,621 | 119,851 |
| Administrative | | | | |
| Cash administrative expenses | 2,819 | 3,477 | 11,297 | 14,380 |
| Depreciation | 75 | 94 | 322 | 364 |
| Stock based compensation | 102 | (10) | 345 | 412 |
| Total administrative expenses | 2,996 | 3,561 | 11,964 | 15,156 |
| Gross Margin[1] | 5,345 | 9,417 | 18,044 | 64,759 |
| Gross Margin as a percentage of Operating Revenue | 18% | 35% | 23% | 43% |
| Adjusted EBITDA[1] | 2,526 | 5,940 | 6,747 | 50,379 |
| Adjusted EBITDA as a percentage of Operating Revenue | 9% | 22% | 9% | 34% |
| Operating Earnings[1] | (10,662) | (25) | (38,899) | 23,675 |
| Capital expenditures | 2,158 | 2,037 | 3,154 | 26,314 |

| **Operating Highlights** | | | | |
|---|---|---|---|---|
| **Canadian Operations** | | | | |
| Contract drilling rig fleet: | | | | |
| Average active rig count[1] | 16.2 | 11.4 | 10.0 | 14.3 |
| End of period | 51 | 52 | 51 | 52 |
| Operating Revenue per Revenue Day[1] | 16,657 | 22,038 | 16,984 [3] | 23,458 |
| Operating Revenue per Operating Day[1] | 18,811 | 24,228 | 19,058 [3] | 25,821 |
| Operating Days[1] | 1,317 | 955 | 3,276 | 4,748 |
| Number of meters drilled | 349,172 | 220,296 | 822,293 | 1,038,946 |
| Number of wells drilled | 106 | 66 | 255 | 289 |
| Average Operating Days per well | 12.5 | 14.5 | 12.9 | 16.4 |
| Drilling rig utilization - Revenue Days[1] | 32% | 22% | 20% | 29% |
| Drilling rig utilization - Operating Days[1] | 28% | 20% | 17% | 26% |
| CAODC industry average utilization[1][2] | 25% | 20% | 17% | 23% |
| **United States Operations** | | | | |
| Contract drilling rig fleet: | | | | |
| Average active rig count[1] | 1.7 | 1.0 | 1.4 | 1.6 |
| End of period | 5 | 5 | 5 | 5 |
| Operating Revenue per Revenue Day (US$)[1] | 20,197 | 31,350 | 21,805 | 29,483 [4] |
| Operating Revenue per Operating Day (US$)[1] | 23,440 | 34,217 | 25,166 | 33,166 [4] |
| Operating Days[1] | 134 | 84 | 440 | 526 |
| Number of meters drilled | 32,915 | 18,985 | 127,691 | 138,891 |
| Number of wells drilled | 7 | 3 | 27 | 24 |
| Average Operating Days per well | 20.6 | 25.5 | 16.4 | 21.9 |
| Drilling rig utilization - Revenue Days[1] | 34% | 20% | 28% | 32% |
| Drilling rig utilization - Operating Days[1] | 29% | 18% | 24% | 29% |

(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 $1.8 million for the year ended December 31, 2016.

(4) Excludes shortfall commitment and standby revenue from take or pay contracts of US$4.5 million for the year ended December 31, 2015.

For the year ended December 31, 2016, Operating Revenue in the contract drilling segment totalled $78.9 million, a $71.3 million decrease (or 47%), as compared to the prior year. Reduced demand for 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 put continued downward pressure on day rates in Canada and the United States in 2016.

Contract drilling Adjusted EBITDA in 2016 decreased by $43.7 million (or 87%) to $6.7 million, as compared to $50.4 million in the prior year. The decrease for 2016 is mainly due to fewer Operating Days, coupled with lower Operating Revenue per Revenue Day in both Canada and the United States. The decrease in activity and pricing was partially offset by cost control measures implemented throughout the Company.

Cash administrative expenses for 2016, which exclude depreciation and stock based compensation, totalled $11.3 million reflecting a decrease of $3.1 million (or 22%), as compared to the prior year, mainly due to lower employee costs and effective cost control measures.

Depreciation expense in 2016 increased by $18.9 million to $45.6 million as compared to 2015. The increase is due to the use of straight line depreciation effective April 1, 2016, as compared to the unit of production method of depreciation used previously. Due to lower than normal levels of activity, the change in depreciation method resulted in depreciation expense increasing in the current period.

Capital expenditures in the contract drilling segment totalled $3.2 million in 2016, and include $2.1 million of expansion capital and $1.1 million of maintenance capital. Contract drilling capital expenditures for 2016 represent an 88% decrease from the $26.3 million incurred in 2015, when the Company was completing the 2014 drilling rig build program. The Company deployed strategic expansion capital relating to rig upgrades in the fourth quarter of 2016 and incurred only necessary maintenance capital to preserve cash during the current slowdown in oilfield service activity.

*Canadian Operations*

For the year ended December 31, 2016, Drilling Rig Utilization in Canada decreased to 17% as compared to 26% in the prior year. The decrease in utilization is due to reduced demand as the lower commodity price environment continued, resulting in the Company's Operating Days decreasing by 31% on a year over year basis in 2016.

The Company's Drilling Rig Utilization in Canada of 17% in 2016 was consistent with the CAODC industry average of 17%, however lower than the 300 bps premium realized in 2015. The decrease in the Company's utilization premium in 2016 as compared to 2015 is partially due to a 13% reduction in the industry rig count from 765 rigs at December 31, 2015 to 668 rigs at December 31, 2016 as competitors continue to decommission older less competitive rigs given current market conditions. From December 31, 2015 to December 31, 2016, 12 drilling rigs were added to the industry fleet while 109 drilling rigs were removed by decommissioning or movement out of the WCSB. Of the rigs added year over year, the majority of new additions directly compete with Western's Montney and Duvernay class rig fleet, which impacts Western's utilization premium to the industry average. Additionally, the year over year change relative to the CAODC industry average is partially due to a number of Western's customers, who typically have substantial drilling programs, significantly cutting their capital spending in 2016, particularly in the first three quarters of 2016.

For the year ended December 31, 2016, Operating Revenue per Revenue Day in Canada totalled $16,984 compared to $23,458 in the prior year, a reduction of 28%. The decrease is mainly due to downward pricing pressure on day rates across all rig categories, as reduced commodity prices have led to lower customer spending and resulted in decreased activity and increased competition. Third party charges per Revenue Day of $1,300 in 2016 were consistent with the prior year.

*United States Operations*

For the year ended December 31, 2016, Operating Days decreased by 86 days (or 16%) resulting in Drilling Rig Utilization of 24% compared to 29% in the prior year. Additionally, 2016 Operating Revenue per Revenue Day in the United States decreased by 26% to US$21,805 due to renegotiating the day rate, as a result of extending the term on a long term contract, coupled with pricing pressure on spot market rates. In the Williston basin in North Dakota, where the Company operates in the United States, drilling rig counts decreased by approximately 38% to 33 active drilling rigs at December 31, 2016, as compared to 53 active drilling rigs at December 31, 2015.

**Production Services**

| Financial Highlights (stated in thousands) | Three months ended December 31 2016 | 2015 | Year ended December 31 2016 | 2015 |
|---|---|---|---|---|
| Revenue | | | | |
| Operating Revenue(1) | 12,710 | 13,525 | 38,064 | 66,550 |
| Third party charges | 715 | 806 | 2,364 | 3,412 |
| Total revenue | 13,425 | 14,331 | 40,428 | 69,962 |
| Expenses | | | | |
| Operating | | | | |
| Cash operating expenses | 10,264 | 10,376 | 32,710 | 48,770 |
| Depreciation | 3,438 | 2,562 | 12,579 | 11,133 |
| Stock based compensation | 54 | 142 | 345 | 406 |
| Total operating expenses | 13,756 | 13,080 | 45,634 | 60,309 |
| Administrative | | | | |
| Cash administrative expenses | 1,546 | 1,578 | 6,014 | 6,694 |
| Depreciation | 84 | 102 | 398 | 415 |
| Stock based compensation | 8 | 127 | 253 | 384 |
| Total administrative expenses | 1,638 | 1,807 | 6,665 | 7,493 |
| Gross Margin(1) | 3,161 | 3,955 | 7,718 | 21,192 |
| Gross margin as a percentage of Operating Revenue | 25% | 29% | 20% | 32% |
| Adjusted EBITDA(1) | 1,615 | 2,377 | 1,704 | 14,498 |
| Adjusted EBITDA as a percentage of Operating Revenue | 13% | 18% | 4% | 22% |
| Operating Earnings(1) | (1,907) | (287) | (11,273) | 2,950 |
| Capital expenditures | 566 | 1,188 | 1,564 | 7,109 |

| Operating Highlights | | | | |
|---|---|---|---|---|
| Well servicing rig fleet: | | | | |
| Average active rig count(1) | 17.6 | 16.7 | 12.9 | 19.5 |
| End of period | 66 | 66 | 66 | 66 |
| Service rig Operating Revenue per Service Hour(1) | 638 | 703 | 643 | 779 |
| Service Hours(1) | 16,182 | 15,352 | 47,305 | 71,225 |
| Service rig utilization (1) | 27% | 25% | 20% | 30% |

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

The Company's production services segment includes Eagle's well servicing fleet, which totals 66 rigs, as well as Aero's oilfield rental equipment. Operating Revenue for the year ended December 31, 2016 decreased by $28.5 million (or 43%) to $38.1 million, compared to $66.6 million in the prior year. In 2016, Eagle's contribution to Operating Revenue in the production services segment of $30.4 million compared to $55.5 million in the prior year, whereas Aero's contribution to Operating Revenue in the production services segment of $7.7 million compared to $11.1 million in the prior year. The decrease in Operating Revenue for both Eagle and Aero for the year ended December 31, 2016, as compared to the prior year, is due to reduced customer spending resulting from the decreased commodity price environment leading to lower pricing and activity.

Eagle's Service Hours decreased by 34% in 2016 to 47,305 (20% utilization) as compared to 71,225 (30% utilization) in the prior year. The reduction in Service Hours in 2016 is due to lower demand and increased competition across all geographic areas. Operating Revenue per Service Hour decreased by 17% for the year ended December 31, 2016 to $643, as compared to the prior year, due to competitive pricing pressure across all operating areas.

Adjusted EBITDA decreased by 88% to $1.7 million in 2016 compared to $14.5 million in 2015. The lower Adjusted EBITDA in 2016 was due to the decreased commodity price environment, which impacted the demand and pricing for the Company's services, and was partially offset by lower employee costs and cost control measures.

During the year ended December 31, 2016, cash administrative expenses, which exclude depreciation and stock based compensation, decreased by 10% to $6.0 million as compared to the prior year, due to lower employee costs and effective cost control measures.

Depreciation expense for 2016 increased by 13% to $13.0 million, as compared to $11.5 million in 2015. The increase in 2016 is due to the use of straight line depreciation effective April 1, 2016, as compared to the unit of production method of depreciation used previously. Due to lower than normal levels of activity, the change in depreciation methodology resulted in depreciation expense increasing in the current period.

During the year ended December 31, 2016, capital expenditures in the production services segment totalled $1.6 million and included expansion capital of $0.9 million and maintenance capital of $0.7 million. Total production services capital expenditures in 2016, represent a 77% decrease from the $7.1 million incurred in 2015, as the Company only incurred necessary maintenance capital to preserve cash during the current slowdown in oilfield service activity.

**Corporate**

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| **(stated in thousands)** | **2016** | **2015** | **2016** | **2015** |
| Administrative | | | | |
| Cash administrative expenses | 635 | 744 | 2,676 | 4,332 |
| Depreciation | 206 | 420 | 849 | 1,215 |
| Stock based compensation | 375 | 804 | 2,537 | 2,724 |
| Total administrative expenses | 1,216 | 1,968 | 6,062 | 8,271 |
| Finance costs | 5,478 | 5,412 | 22,522 | 20,441 |
| Other items | (83) | (221) | (1,549) | (1,709) |
| Income taxes | | | | |
| Current tax recovery | (511) | (2,692) | (1,708) | (8,732) |
| Deferred tax recovery | (4,672) | (18,581) | (20,247) | (3,816) |
| Total income taxes | (5,183) | (21,273) | (21,955) | (12,548) |
| Operating earnings (1) | (841) | (1,164) | (3,525) | (5,547) |
| Capital expenditures | - | 34 | 1 | 139 |

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

Corporate cash administrative expenses, which exclude depreciation and stock based compensation, for the year ended December 31, 2016 decreased by 37% to $2.7 million as compared to the prior year, mainly due to lower headcount year over year and a 10% salary rollback implemented in the first quarter of 2016.

Finance costs in 2016 on a consolidated basis increased by $2.1 million as compared to the prior year, mainly due to higher capitalized interest in 2015, as a result of the completion of the 2014 rig build program. The Company had an effective interest rate on its borrowings of 8.5% throughout 2016 and 8.2% throughout 2015.

Other items, which totalled a net gain of $1.5 million for the year ended December 31, 2016, consist of gains and losses on foreign exchange, asset sales and derivatives.

For the year ended December 31, 2016, income taxes on a consolidated basis totalled a recovery of $22.0 million, representing an effective tax rate of 26.2%, as compared to an effective tax rate of 8.9% in 2015. The tax rate in 2015 was impacted by the prior year goodwill impairment of $71.3 million, as well as the increase in the Alberta corporate tax rate to 12% in the second quarter of 2015 from 10% previously. The effective tax rate of 26.2% for 2016 represents a more normalized period of operations. The current tax recovery for the year ended December 31, 2016 of $1.7 million is due to the recognition of tax losses during the period, expected to be carried back to prior taxation years.

**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 existing credit facilities, new debt instruments, equity issuances and proceeds from the sale of assets. As at December 31, 2016, Western had cash and cash equivalents of $44.6 million, a decrease of $13.8 million from December 31, 2015. Western's consolidated Net Debt balance at December 31, 2016 was $220.2 million. During the year ended December 31, 2016, Western had Adjusted EBITDA of $5.8 million, net income tax refunds of $8.3 million, $2.7 million in foreign exchange gains, proceeds on the sale of property and equipment of $0.5 million and a positive change in non-cash working capital of $0.4 million, which was offset by cash interest payments of $21.6 million, capital expenditures of $4.7 million, dividend payments of $3.7 million and long term debt repayments of $0.7 million.

As at December 31, 2016, Western had a working capital balance of $51.1 million, a $19.6 million decrease as compared to December 31, 2015 mainly due to the decrease in cash and cash equivalents in 2016. Currently, the Company has $265.0 million in Senior Notes outstanding. In addition to the $60.0 million of available credit under the Credit Facilities, Western has access to an accordion feature whereby an incremental $50.0 million of borrowing would become available, subject to the approval of the lenders. The Credit Facilities include a covenant relief period from January 1, 2016 to December 31, 2017, during which the interest coverage ratio has been waived. During the covenant relief period, there are restrictions on exercising the accordion and on certain payments made by the Company, including dividends, share repurchases and capital expenditures in excess of Western's approved budget. The Credit Facilities mature on December 17, 2018.

Additionally, advances under the Credit Facilities will be limited by the Company's borrowing base. 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, with a seasonal increase to $50.0 million each quarter ending June 30).

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. Adjusted 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. As at December 31, 2016, the Revolving Facility and the Operating Facility were undrawn. A summary of the Company's financial covenants as at December 31, 2016 is as follows:

| December 31, 2016 | Covenants |
|---|---|
| Maximum Consolidated Senior Debt to Consolidated EBITDA Ratio (1) | 3.0:1.0 or less |
| Maximum Consolidated Debt to Consolidated Capitalization Ratio (1) | 0.6:1.0 or less |
| Minimum Consolidated EBITDA to Consolidated Interest Expense Ratio (1)(2) | Not applicable |
| Minimum Current Ratio (1) | 1.15:1.0 or more |

(1) See covenant definitions in Note 12 of the December 31, 2016 annual financial statements.

(2) Consolidated EBITDA to Consolidated interest Expense is only applicable after December 31, 2017, when $30.0 million or more is drawn on the Credit Facilities. Subsequent to December 31, 2017, the ratio must exceed 1.0 and 1.25 in the first and second quarters of 2018 respectively, and 1.5 thereafter.

At December 31, 2016, Western is in compliance with all debt covenants under its Credit Facilities and has 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.

For the years ended December 31, 2016 and 2015 the Company had one significant customer comprising 10.0% and 10.7% respectively, of the Company's total revenue. The trade receivable balance outstanding relating to the significant customer in 2016 as at December 31, 2016 represented 3.8% of the Company's total trade and other receivables. The Company's significant customers may change from period to period.

**Fourth Quarter 2016**

**Selected Financial Information**

| **Financial Highlights** | **Three months ended December 31** | |
|---|---|---|
| **(stated in thousands, except share and per share amounts)** | **2016** | **2015** |
| Total Revenue | 45,126 | 42,678 |
| Operating Revenue | 41,649 | 40,458 |
| Gross Margin (1) | 8,507 | 13,372 |
| Gross Margin as a percentage of operating revenue | 20% | 33% |
| EBITDA (1) | 3,506 | 7,573 |
| EBITDA as a percentage of operating revenue | 8% | 19% |
| Cash flow from operating activities | (1,327) | 11,139 |
| Capital expenditures | 2,724 | 3,259 |
| Net loss | (14,509) | (55,010) |
| -basic net loss per share | (0.20) | (0.75) |
| -diluted net loss per share | (0.20) | (0.75) |
| Weighted average number of shares | | |
| -basic | 73,795,896 | 73,655,198 |
| -diluted | 73,795,896 | 73,655,198 |
| Outstanding common shares as at period end | 73,795,944 | 73,646,292 |
| Dividends declared | - | 3,682 |
| Dividends declared per common share | - | 0.05 |

| **Operating Highlights** | | |
|---|---|---|
| **Contract Drilling** | | |
| *Canadian Operations* | | |
| Average active rig count (1) | 16.2 | 11.4 |
| Contract drilling rig fleet - end of period | 51 | 52 |
| Operating Revenue per Revenue Day (1) | 16,657 | 22,038 |
| Operating Revenue per Operating Day (1) | 18,811 | 24,228 |
| Operating Days (1) | 1,317 | 955 |
| Number of meters drilled | 349,172 | 220,296 |
| Number of wells drilled | 106 | 66 |
| Average operating days per well | 12.5 | 14.5 |
| Drilling rig utilization - Revenue Days (1) | 32% | 22% |
| Drilling rig utilization - Operating Days (1) | 28% | 20% |
| CAODC industry average utilization rate (2) | 25% | 20% |
| | | |
| *United States Operations* | | |
| Average active rig count (1) | 1.7 | 1.0 |
| Contract drilling rig fleet - end of period | 5 | 5 |
| Operating Revenue per Revenue Day (US$) (1) | 20,197 | 31,350 |
| Operating Revenue per Operating Day (US$) (1) | 23,440 | 34,217 |
| Operating Days (1) | 134 | 84 |
| Number of meters drilled | 32,915 | 18,985 |
| Number of wells drilled | 7 | 3 |
| Average operating days per well | 20.6 | 25.5 |
| Drilling rig utilization - Revenue Days (1) | 34% | 20% |
| Drilling rig utilization - Operating Days (1) | 29% | 18% |
| | | |
| **Production Services** | | |
| Average active rig count (1) | 17.6 | 16.7 |
| Well servicing rig fleet - end of period | 66 | 66 |
| Service rig Operating Revenue per Service Hour (1) | 638 | 703 |
| Service Hours (1) | 16,182 | 15,352 |
| Service rig utilization (1) | 27% | 25% |

(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.

**Consolidated**

Fourth quarter Operating Revenue increased by $1.2 million (or 3%) to $41.7 million in 2016 as compared to $40.4 million in the same period of the prior year. In the contract drilling segment, Operating Revenue increased by $2.0 million (or 7%) to $29.0 million in the fourth quarter of 2016 as compared to $27.0 million in the fourth quarter of 2015; while in the production services segment, Operating Revenue decreased by $0.8 million (or 6%) during the three months ended December 31, 2016 to $12.7 million as compared to $13.5 million in the same period of the prior year. The increase in consolidated Operating Revenue is a result of higher utilization due to built up demand due to wet weather in the previous quarter, which was partially offset by lower pricing in both the contract drilling and production services segments, which continued to be impacted by cyclically low commodity prices.

Adjusted EBITDA decreased by $4.1 million (or 54%) to $3.5 million in the fourth quarter of 2016, as compared to $7.6 million in 2015. The decrease in Adjusted EBITDA is due to lower pricing in both the contract drilling and production services segments, offset partially by improved activity in the fourth quarter of 2016, coupled with cost reduction measures, including a reduced headcount year over year, and wage reductions to all employees.

**Contract Drilling**

During the fourth quarter of 2016, Operating Revenue in the contract drilling segment totalled $29.0 million, a $2.0 million increase (or 7%), as compared to the fourth quarter of 2015. The fourth quarter of 2016 saw improvements in utilization in Canada, as weather related delays experienced in the third quarter of 2016 resulted in Western’s customers postponing their drilling programs into the fourth quarter, which increased overall demand in the latter half of the quarter. While commodity prices began to improve in the fourth quarter of 2016, the continued low commodity price environment put downward pressure on day rates in Canada and the United States in 2016. Operating Revenue per Revenue Day in Canada and the United States decreased 24% and 36% respectively, in the fourth quarter of 2016, as compared to the fourth quarter of 2015.

During the fourth quarter of 2016, Adjusted EBITDA in the contract drilling segment decreased by $3.4 million (or 58%) to $2.5 million, as compared to $5.9 million in the fourth quarter of 2015. The decrease in the fourth quarter of 2016, is mainly due to lower Operating Revenue per Revenue Day in both Canada and the United States. The decrease in pricing was partially offset by improved utilization, as well as cost control measures implemented throughout the Company.

For the three months ended December 31, 2016, cash administrative expenses, which exclude depreciation and stock based compensation, decreased 20% to $2.8 million, compared to $3.5 million in the same period of the prior year. The decrease is mainly due to lower employee costs and effective cost control measures.

Depreciation expense for the quarter ended December 31, 2016 increased by $7.2 million, as compared to the same period in the prior year, mainly due to the use of straight line depreciation effective April 1, 2016, as compared to the unit of production method of depreciation used previously. Due to lower than normal levels of activity, the change in depreciation method resulted in depreciation expense increasing in the current period.

Capital expenditures in the contract drilling segment totalled $2.2 million in the fourth quarter of 2016 and include $1.8 million related to expansion capital, and $0.4 million related to maintenance capital. Contract drilling capital expenditures represent a 6% increase from the $2.0 million incurred in the three months ended December 31, 2015. During the fourth quarter of 2016, the Company incurred expansion capital relating to rig upgrades and only incurred necessary maintenance capital to preserve cash during the current slowdown in oilfield service activity.

*Canadian Operations*

During the fourth quarter of 2016, Drilling Rig Utilization improved on a year over year basis to 28%, as compared to 20% in the same period of the prior year. Fourth quarter Drilling Rig Utilization of 28% was also higher than the third quarter of 2016, when Drilling Rig Utilization of 20% was impacted by weather related delays. Additionally, the Company achieved a 300 bps premium to the CAODC average in the fourth quarter of 2016, as compared to the same period of the prior year when the Company’s utilization was consistent with the CAODC average of 20%. While activity levels improved during the quarter, increased pricing pressure due to the current competitive environment in which the Company operates resulted in Operating Revenue per Revenue Day in Canada decreasing 24% to $16,657, compared to $22,038 in the same period of the prior year. Third party charges per Revenue Day increased in the fourth quarter of 2016 to approximately $1,800 as compared to approximately $1,300 per Revenue Day in the fourth quarter of 2015, due to increased fuel purchases, which are subsequently recharged to the customer.

*United States Operations*

For the quarter ended December 31, 2016, Operating Days increased by 50 (or 59%), resulting in Drilling Rig Utilization of 29% compared to 18% in the same period of the prior year and 32% in the third quarter of 2016. Additionally, fourth quarter 2016 Operating Revenue per Revenue Day in the United States decreased by 36%, mainly due to the renegotiation of the day rate as a result of extending the term on a long term contract, and pricing pressure on spot market rates due to the decreased commodity price environment resulting in lower activity and increased competition.

**Production Services**

During the fourth quarter of 2016, Operating Revenue decreased by $0.8 million (or 6%) to $12.7 million, compared to $13.5 million in the fourth quarter of 2015. For the quarter ended December 31, 2016, Eagle's contribution to Operating Revenue in the production services segment decreased by $0.5 million (or 5%) to $10.3 million as compared to $10.8 million in the same period of the prior year, whereas Aero's contribution to Operating Revenue in the production services segment decreased by $0.3 million (or 11%) to $2.4 million, compared to $2.7 million in the fourth quarter of 2015. The decrease in Operating Revenue for both Eagle and Aero for the three months ended December 31, 2016, as compared to the same period in the prior year, is due to reduced customer spending resulting from the decreased commodity price environment as well as increased competition, leading to lower pricing.

While competition and the low commodity price environment continued to impact the fourth quarter of 2016, Eagle's utilization improved to 27% in the fourth quarter of 2016, as compared to 24% in the third quarter of 2016 and 25% in the fourth quarter of 2015. Additionally, Eagle's Operating Revenue per Service Hour in the fourth quarter of 2016 improved by 6% to $638 per hour from the third quarter of 2016, however was 9% lower than the fourth quarter of 2015.

The increased activity for the three months ended December 31, 2016 was partially due to built up demand resulting from weather related delays experienced in the third quarter of 2016, forcing customers to delay their programs until the fourth quarter of 2016.

Adjusted EBITDA decreased by 33% to $1.6 million during the fourth quarter of 2016 from $2.4 million in the fourth quarter of 2015 mainly due to the decreased commodity price environment impacting the pricing for the Company's services, which was partially offset by improved activity, lower employee costs and cost control measures. However, Adjusted EBITDA continued to recover in the fourth quarter of 2016 to $1.6 million, the highest quarterly Adjusted EBITDA for the production services segment in 2016, due to continued marketing efforts and cost control measures.

During the fourth quarter of 2016, cash administrative expenses, which exclude depreciation and stock based compensation, decreased by 6% to $1.5 million as compared to $1.6 million in the same period of the prior year due to lower employee costs and effective cost control measures.

For the three months ended December 31, 2016, depreciation expense increased by 30% to $3.5 million mainly due to the use of straight line depreciation effective April 1, 2016, as compared to the unit of production method of depreciation used previously. Due to lower than normal levels of activity, the change in depreciation method resulted in depreciation expense increasing in the current period.

During the three months ended December 31, 2016, capital expenditures in the production services segment totalled $0.6 million, representing a 50% decrease from the $1.2 million incurred in the fourth quarter of 2015, and mainly related to necessary maintenance capital and the purchase of additional oilfield rental equipment.

**Corporate**

Corporate cash administrative expenses, which exclude depreciation and stock based compensation, for the three month period ended December 31, 2016 decreased by 14% to $0.6 million mainly due to lower headcount year over year and a 10% salary rollback implemented in the first quarter of 2016.

For the three month period ended December 31, 2016, finance costs on a consolidated basis remained relatively consistent at $5.5 million, as compared to $5.4 million in the same period of the prior year. The Company had an effective interest rate on its borrowings of 8.2% during the fourth quarter of 2016, as compared to 8.1% in the same period of the prior year.

Other items of $0.1 million for the three months ended December 31, 2016 consist of net gains and losses on foreign exchange, asset sales and derivatives.

For the three months ended December 31, 2016, income taxes on a consolidated basis totalled a recovery of $5.2 million and represent an effective tax rate of 26.3%, as compared to an effective tax rate of 27.9% during the three months ended December 31, 2015. The current tax recovery for the three months ended December 31, 2016 of $0.5 million is mainly due to the recognition of tax losses during the period, expected to be carried back to prior taxation years.

**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<br>(stated in thousands, except per share amounts) | Dec 31, 2016 | Sept 30, 2016 | Jun 30, 2016 | Mar 31, 2016 | Dec 31, 2015 | Sep 30, 2015 | Jun 30, 2015 | Mar 31, 2015 |
|---|---|---|---|---|---|---|---|---|
| Revenue | 45,126 | 32,485 | 12,890 | 33,937 | 42,678 | 46,959 | 32,037 | 105,850 |
| Operating Revenue (1) | 41,649 | 30,665 | 12,393 | 32,200 | 40,458 | 44,350 | 30,719 | 100,958 |
| Gross Margin (1) | 8,507 | 5,685 | 2,703 | 8,867 | 13,372 | 14,285 | 10,403 | 47,891 |
| Adjusted EBITDA (1) | 3,506 | 896 | (1,990) | 3,364 | 7,573 | 8,080 | 4,255 | 40,637 |
| Cash flow from operating activities | (1,327) | 909 | 8,444 | 8,604 | 11,139 | (530) | 41,009 | 39,337 |
| Net income (loss) | (14,509) | (16,973) | (24,172) | (6,319) | (55,010) | (76,816) | (12,607) | 15,294 |
| per share - basic | (0.20) | (0.23) | (0.33) | (0.09) | (0.75) | (1.04) | (0.17) | 0.20 |
| per share - diluted | (0.20) | (0.23) | (0.33) | (0.09) | (0.75) | (1.04) | (0.17) | 0.20 |
| Total assets | 793,525 | 794,170 | 814,757 | 842,492 | 876,608 | 947,137 | 1,025,776 | 1,049,145 |
| Long term debt | 264,070 | 264,118 | 264,145 | 264,118 | 264,155 | 264,219 | 264,234 | 264,207 |
| Dividends declared | - | - | - | - | 3,682 | 5,526 | 5,591 | 5,593 |

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

Revenue and Adjusted EBITDA were impacted by lower commodity prices in 2015 and 2016, declining significantly following the first quarter of 2015, and throughout 2016. During the first quarter of 2015, revenue and Adjusted EBITDA were significantly higher due to greater activity levels and pricing in both the contract drilling and production services segments as the full impact of the downturn in the oilfield service industry had not yet been realized. Subsequent to the first quarter of 2015, the lower commodity price environment has significantly impacted revenue and Adjusted EBITDA, with Revenue and Adjusted EBITDA beginning to recover in the fourth quarter of 2016.

Net income has fluctuated throughout the last eight quarters in part due to the seasonal nature of the oilfield service industry in Canada and the prolonged decline in crude oil and natural gas prices. In addition, the Company recorded impairments in the third quarter of 2015 totalling $71.3 million and $68.5 million in the fourth quarter of 2015, significantly impacting net income in each of the respective periods. A decommissioning loss of $5.2 million was recorded and the Company changed its depreciation methodology from unit of production to straight line in the second quarter of 2016, which significantly impacted net income.

Total assets over the last eight quarters have been impacted by the impairments noted above and the change in depreciation methodology.

**Contractual Obligations**

In the normal course of business the Company incurs contractual obligations. The expected maturities of the Company's contractual obligations as at December 31, 2016 are as follows:

| (stated in thousands) | 2017 | 2018 | 2019 | 2020 | 2021 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Senior Notes | - | - | 265,000 | - | - | - | 265,000 |
| Senior Notes interest | 20,869 | 20,869 | 10,520 | - | - | - | 52,258 |
| Trade payables and other current liabilities (1) | 24,044 | - | - | - | - | - | 24,044 |
| Operating leases | 3,879 | 3,705 | 3,550 | 3,525 | 2,818 | 7,814 | 25,291 |
| Purchase commitments | 2,449 | - | - | - | - | - | 2,449 |
| Other long term debt | 719 | 168 | - | - | - | - | 887 |
| Total | 51,960 | 24,742 | 279,070 | 3,525 | 2,818 | 7,814 | 369,929 |

(1) Trade payables and other current liabilities exclude the Company's interest accrued as at December 31, 2016 on the Senior Notes.

There have been no material changes in the contractual obligations detailed above, other than in the normal course of business, during the year ended December 31, 2016.

**Outstanding Share Data**

| | February 22, 2017 | December 31, 2016 | December 31, 2015 |
|---|---|---|---|
| Common shares outstanding | 73,795,944 | 73,795,944 | 73,646,292 |
| Restricted share units outstanding - equity settled | 415,717 | 410,311 | 410,269 |
| Stock options outstanding | 6,211,701 | 6,153,886 | 6,058,906 |

**Off Balance Sheet Arrangements**

As at December 31, 2016, Western had no off balance sheet arrangements in place.

**Transactions with Related Parties**

During the years ended December 31, 2016 and 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 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.

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 are classified as 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:

The Company's trade and other receivables are classified as 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.

(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 issuance of common shares are recognized as a deduction from equity, net of any tax effects.

*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 constantly reviews individual customer trade receivables, taking into consideration payment history and the aging of the trade receivable to monitor collectability. 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.

*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, which are currently undrawn. Other long term debt, such as the Senior Notes 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 & Chief Executive Officer ("CEO") and Senior Vice President, Finance & Chief Financial Officer ("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, 2016. 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, 2016, 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, non-derivative financial liabilities and the Company's allowance for doubtful accounts.

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

*Business Combinations*

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

*Impairment*

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

When there is an indicator 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, whereas for goodwill the recoverable amount is based on the value in use calculation. In assessing fair value less costs to sell, 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, discount rates and asset useful lives.

If indicators conclude that the asset is no longer impaired, the Company will reverse impairment losses on assets. Impairment losses on goodwill are not reversed. Similar to determining if an impairment exists, judgment is required in assessing if a reversal of an impairment loss is required. Value-in-use and fair value less cost to sell calculations performed in assessing the recoverable amounts incorporate a number of key estimates. As at December 31, 2016, the Company identified impairment indicators related to the prolonged commodity price downturn and as such performed an impairment analysis on each of its CGUs. The results of the impairment test indicated no impairment existed as at December 31, 2016. Additionally, there were no reversals of previous property and equipment impairment losses during the year ended December 31, 2016.

*Property and equipment*

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

*Income taxes*

Preparation of the 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 value of employee stock options and equity settled restricted share units ("RSUs") 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.

The 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.

*Non-derivative financial liabilities*

The Company records its financial instruments at fair value on inception with changes in fair value recorded when required by the Company's classification of such instruments.

Calculation of the fair value of the Company's financial instruments is complex and requires judgment around the selection of market inputs and is based on many variables including but not limited to credit spreads and interest rate spreads which are factors outside management's control.

The fair value of non-derivative financial liabilities for disclosure purposes is calculated based on the present value of future principal and interest payments, discounted at the market rate of interest at the reporting date. For finance leases, the market rate of interest is determined by reference to similar lease agreements.

*Allowance for doubtful accounts*

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

**Business Risks**

For a comprehensive listing of the Company's business risks please see the most recent Annual Information Form for the year ended December 31, 2016 as filed on SEDAR at www.sedar.com. The Company's primary business risks as at December 31, 2016 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.

- The current low commodity price environment is expected to continue throughout 2017. If a low commodity price environment persists as expected, 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 and under its Senior Note indenture, 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's exploration and production customers' facilities and other operations emit greenhouse gases and require them to comply with legislation in those provinces and states where they operate. On November 22, 2015, the Alberta government announced new emissions regulations, including an economy wide price on carbon emissions effective January 1, 2017 and methane emission reductions. In September 2016, the Canadian Federal government announced its intention to impose a national carbon price on the provinces, requiring provinces to adopt either a carbon price or cap-and-trade approach and to meet a federally established minimum price. The direct or indirect costs of these new greenhouse gas emission reduction regulations, as well as regulations which may be adopted in these or other jurisdictions in the future, may have a material adverse effect on the Company's business, financial condition and results of operations and cash flows, as well as impacting the Company's customers' operations.
- In addition to global economic events and uncertainty, the capacity within North America to ship commodities to market introduces uncertainties in levels of activity and pricing for crude oil and natural gas production.
- The Company is vulnerable to market prices. Fixed costs, including costs associated with operations, 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 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.
- During the prolonged downturn many oilfield service workers have left the industry and, therefore, if activity increases it may be 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 Senior Notes.
- 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 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 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 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)** | **2016** | **2015** | **2016** | **2015** |
| **Operating Revenue** | | | | |
| Drilling | 28,965 | 26,978 | 78,887 | 150,252 |
| Production services | 12,710 | 13,525 | 38,064 | 66,550 |
| Less: inter-company eliminations | (26) | (45) | (44) | (317) |
| | **41,649** | **40,458** | **116,907** | **216,485** |
| Third party charges | 3,477 | 2,220 | 7,531 | 11,039 |
| **Revenue** | **45,126** | **42,678** | **124,438** | **227,524** |
| Less: operating expenses | (53,308) | (37,974) | (157,212) | (179,843) |
| Add: | | | | |
| Depreciation - operating | 16,551 | 8,433 | 57,903 | 37,473 |
| Stock based compensation - operating | 138 | 235 | 633 | 797 |
| **Gross Margin** | **8,507** | **13,372** | **25,762** | **85,951** |

*Adjusted EBITDA*

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

*Operating Earnings*

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 segments 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 consolidated statements of operations and comprehensive income, to earnings before interest and finance costs, taxes, depreciation and amortization ("EBITDA"), Adjusted EBITDA and Operating Earnings (Loss):

| | Three months ended December 31 | | Year ended December 31 | |
|---|---|---|---|---|
| **(stated in thousands)** | **2016** | **2015** | **2016** | **2015** |
| **Net loss** | **(14,509)** | **(55,010)** | **(61,973)** | **(129,139)** |
| Add: | | | | |
| Finance costs | 5,478 | 5,412 | 22,522 | 20,441 |
| Income tax recovery | (5,183) | (21,273) | (21,955) | (12,548) |
| Depreciation - operating | 16,551 | 8,433 | 57,903 | 37,473 |
| Depreciation - administrative | 365 | 616 | 1,569 | 1,994 |
| **EBITDA** | **2,702** | **(61,822)** | **(1,934)** | **(81,779)** |
| Add: | | | | |
| Stock based compensation - operating | 138 | 235 | 633 | 797 |
| Stock based compensation - administrative | 484 | 921 | 3,135 | 3,520 |
| Impairment of goodwill | - | - | - | 71,256 |
| Impairment of property and equipment | - | 41,862 | - | 41,862 |
| Loss on asset decommissioning | 265 | 26,598 | 5,490 | 26,598 |
| Other items | (83) | (221) | (1,549) | (1,709) |
| **Adjusted EBITDA** | **3,506** | **7,573** | **5,775** | **60,545** |
| Subtract: | | | | |
| Depreciation - operating | (16,551) | (8,433) | (57,903) | (37,473) |
| Depreciation - administrative | (365) | (616) | (1,569) | (1,994) |
| **Operating Earnings (Loss)** | **(13,410)** | **(1,476)** | **(53,697)** | **21,078** |

*Net 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, 2016** | **December 31, 2015** |
|---|---|---|
| Long term debt | 264,070 | 264,155 |
| Current portion of long term debt | 684 | 761 |
| Less: cash and cash equivalents | (44,597) | (58,445) |
| **Net Debt** | **220,157** | **206,471** |

Defined Terms:

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

*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 quarter or year.

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

*Drilling rig utilization – Revenue Days:* 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 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, 366 days per year in 2016 (2015: 365 days).

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”);
- West Texas Intermediate (“WTI”); and
- Western Canadian Sedimentary Basin (“WCSB”).

**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 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 2017; the Company’s liquidity needs including the ability of current capital resources to cover Western’s financial obligations and the 2017 capital budget; the Company’s expected sources of funding to support such capital plans and the Company’s ability to adjust capital spending for the remainder of 2017 if market conditions, including customer demand changes; the expected benefits from cost control measures; the use and availability of the Company’s Credit Facilities; the Company’s ability to maintain certain covenants under its Credit Facility; the future declaration of dividends; expectations as to the increase in crude oil transportation capacity through pipeline development; changes to environmental laws and regulations; the implementation of a carbon tax in Alberta; the expectation of continued foreign investment into the Canadian crude oil and natural gas industry; the expectation that producer spending constraints, and finding and maintaining enough field crew members will continue to be large challenges facing the Company in 2017; the Company’s change to its depreciation assumptions; 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 crude oil and natural gas; the continued 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; crude oil transport and pipeline approval and development; the Company’s ability to finance its operations, including but not limited to the ability to refinance its Senior Notes; 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 2017 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.