Q2 2024

Western ENERGY SERVICES CORP.

## Second Quarter 2024 Management's Discussion and Analysis

**Date: July 23, 2024**

*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, 2023 and 2022, management's discussion and analysis ("MD&A") for the year ended December 31, 2023, as well as the condensed consolidated financial statements and notes as at June 30, 2024 and for the three and six months ended June 30, 2024 and 2023. This MD&A is dated July 23, 2024. All amounts are denominated in Canadian dollars (CDN$) unless otherwise identified.*

| **Financial Highlights** | **Three months ended June 30** | | | **Six months ended June 30** | | |
|---|---|---|---|---|---|---|
| **(stated in thousands, except share and per share amounts)** | **2024** | **2023** | **Change** | **2024** | **2023** | **Change** |
| Revenue | 43,033 | 42,954 | - | 105,015 | 122,193 | (14%) |
| Adjusted EBITDA[1] | 5,259 | 4,140 | 27% | 20,478 | 23,336 | (12%) |
| Adjusted EBITDA as a percentage of revenue[1] | 12% | 10% | 20% | 20% | 19% | 5% |
| Cash flow from operating activities | 19,260 | 25,373 | (24%) | 27,062 | 31,818 | (15%) |
| Additions to property and equipment | 5,635 | 6,705 | (16%) | 7,537 | 11,870 | (37%) |
| Net loss | (5,136) | (7,845) | 35% | (3,681) | (3,424) | (8%) |
| -basic and diluted net loss per share | (0.15) | (0.23) | 35% | (0.11) | (0.10) | (10%) |
| Weighted average number of shares | | | | | | |
| -basic and diluted | 33,843,015 | 33,841,324 | - | 33,843,015 | 33,841,324 | - |
| Outstanding common shares as at period end | 33,843,015 | 33,841,324 | - | 33,843,015 | 33,841,324 | - |
| **Operating Highlights[2]** | | | | | | |
| **Contract Drilling** | | | | | | |
| *Canadian Operations* | | | | | | |
| Average active rig count | 7.2 | 6.3 | 14% | 8.8 | 10.3 | (15%) |
| Operating Days | 656 | 576 | 14% | 1,609 | 1,859 | (13%) |
| Revenue per Operating Day[1] | 31,765 | 33,218 | (4%) | 33,226 | 33,258 | - |
| Drilling rig utilization | 21% | 19% | 11% | 26% | 30% | (13%) |
| CAOEC industry average utilization[3] | 30% | 25% | 20% | 40% | 35% | 14% |
| Average meters drilled per well | 7,104 | 8,367 | (15%) | 7,550 | 6,828 | 11% |
| Average Operating Days per well | 12.0 | 16.1 | (25%) | 12.9 | 14.0 | (8%) |
| *United States Operations* | | | | | | |
| Average active rig count | 1.7 | 2.9 | (41%) | 1.7 | 3.3 | (48%) |
| Operating Days | 153 | 267 | (43%) | 317 | 594 | (47%) |
| Revenue per Operating Day (US$)[1] | 30,016 | 31,896 | (6%) | 30,967 | 32,515 | (5%) |
| Drilling rig utilization | 24% | 37% | (35%) | 25% | 41% | (39%) |
| Average meters drilled per well | 4,818 | 3,272 | 47% | 5,368 | 3,395 | 58% |
| Average Operating Days per well | 12.3 | 11.9 | 3% | 14.0 | 13.1 | 7% |
| **Production Services** | | | | | | |
| Average active rig count | 20.7 | 15.1 | 37% | 24.5 | 21.6 | 13% |
| Service Hours | 13,444 | 9,844 | 37% | 31,843 | 28,097 | 13% |
| Revenue per Service Hour[1] | 1,016 | 1,052 | (3%) | 1,040 | 1,039 | - |
| Service rig utilization | 33% | 23% | 43% | 38% | 33% | 15% |

(1) See "Non-IFRS Measures and Ratios" on page 13 of this MD&A.

(2) See "Defined Terms" on page 14 of this MD&A.

(3) Source: The Canadian Association of Energy Contractors ("CAOEC") monthly Contractor Summary. The CAOEC industry average is based on Operating Days divided by total available days. From June 30, 2023 to June 30, 2024, there were 54 drilling rigs deregistered with the CAOEC, which resulted in higher industry average utilization in the three and six months ended June 30, 2024.

| Financial Position at (stated in thousands) | June 30, 2024 | December 31, 2023 | June 30, 2023 |
|---|---|---|---|
| Working capital (1) | 22,203 | 20,125 | 19,576 |
| Total assets | 433,354 | 442,933 | 456,746 |
| Long term debt - non current portion | 106,912 | 111,174 | 118,109 |

(1) See "Non-IFRS Measures and Ratios" on page 13 of this MD&A.

Non-International Financial Reporting Standards ("Non-IFRS") measures and ratios, such as Adjusted EBITDA (as defined in this MD&A), Adjusted EBITDA as a percentage of revenue, revenue per Operating Day, revenue per Service Hour and Working Capital are defined on page 13 of this MD&A. Other defined terms, abbreviations and definitions for standard industry terms are included on page 14 of this MD&A.

**Business Overview**

Western is an energy services company that provides contract drilling services in Canada and in the United States ("US") and production services in Canada through its various divisions, its subsidiary, and its first nations relationships.

*Contract Drilling*

Western markets a fleet of 41 drilling rigs specifically suited for drilling complex horizontal wells across Canada and the US. Western is currently the fourth largest drilling contractor in Canada, based on the Canadian Association of Energy Contractors ("CAOEC") registered drilling rigs[1].

Western's marketed and owned contract drilling rig fleets are comprised of the following:

| | As at June 30 | | | | | |
|---|---|---|---|---|---|---|
| | 2024 | | | 2023 | | |
| Rig class (1) | Canada | US | Total | Canada | US | Total |
| Cardium | 11 | - | 11 | 11 | 1 | 12 |
| Montney | 18 | 1 | 19 | 18 | 1 | 19 |
| Duvernay | 5 | 6 | 11 | 5 | 6 | 11 |
| **Total marketed drilling rigs (2)** | **34** | **7** | **41** | **34** | **8** | **42** |
| **Total owned drilling rigs** | **48** | **7** | **55** | **48** | **8** | **56** |

(1) See "Contract Drilling Rig Classifications" on page 14 of this MD&A.
(2) Source: CAOEC Contractor Summary as at July 23, 2024.

*Production Services*

Production services provides well servicing and oilfield equipment rentals in Canada. Western operates 63 well servicing rigs and is the second largest well servicing company in Canada based on CAOEC registered well servicing rigs[2].

Western's well servicing rig fleet is comprised of the following:

| Owned well servicing rigs | As at June 30 | |
|---|---|---|
| **Mast type** | **2024** | **2023** |
| Single | 28 | 30 |
| Double | 27 | 27 |
| Slant | 8 | 8 |
| **Total owned well servicing rigs** | **63** | **65** |

[1] Source: CAOEC Drilling Contractor Summary as at July 23, 2024.
[2] Source: CAOEC Well Servicing Fleet List as at July 23, 2024.

**Business Environment**

Crude oil and natural gas prices impact the cash flow of Western's customers, which in turn impacts the demand for Western's services. The following table summarizes average crude oil and natural gas prices, as well as average foreign exchange rates, for the three and six months ended June 30, 2024 and 2023.

| | Three months ended June 30 | | | Six months ended June 30 | | |
|---|---|---|---|---|---|---|
| | **2024** | **2023** | **Change** | **2024** | **2023** | **Change** |
| **Average crude oil and natural gas prices**(1)(2) | | | | | | |
| **Crude Oil** | | | | | | |
| West Texas Intermediate (US$/bbl) | 80.57 | 73.80 | 9% | 78.76 | 74.97 | 5% |
| Western Canadian Select (CDN$/bbl) | 91.54 | 78.95 | 16% | 84.68 | 74.04 | 14% |
| **Natural Gas** | | | | | | |
| 30 day Spot AECO (CDN$/mcf) | 1.22 | 2.52 | (52%) | 1.74 | 2.94 | (41%) |
| **Average foreign exchange rates**(2) | | | | | | |
| US dollar to Canadian dollar | 1.37 | 1.34 | 2% | 1.36 | 1.35 | 1% |

(1) See "Abbreviations" on page 14 of this MD&A.

(2) Source: Sproule June 30, 2024, Price Forecast, Historical Prices.

West Texas Intermediate ("WTI") on average increased by 9% and 5% respectively, for the three and six months ended June 30, 2024, compared to the same periods in the prior year. Pricing on Western Canadian Select ("WCS") crude oil increased by 16% and 14% respectively, for the three and six months ended June 30, 2024, compared to the same periods in the prior year. In 2024, crude oil prices improved due to tighter crude oil supplies resulting from OPEC production cuts and ongoing geopolitical conflicts in Ukraine and the Middle East. However, natural gas prices in Canada declined in 2024 due to lower demand, as the 30-day spot AECO price decreased by 52% and 41% respectively, for the three and six months ended June 30, 2024, compared to the same periods of the prior year. Additionally, the US dollar to the Canadian dollar foreign exchange rate for the three and six months ended June 30, 2024 strengthened by 2% and 1% respectively, with the same periods in the prior year.

Despite improved crude oil prices in the first half of 2024 in both the US and Canada, industry drilling activity weakened in the US. As reported by Baker Hughes Company[3], the number of active drilling rigs in the US decreased by approximately 14% to 581 rigs as at June 30, 2024, as compared to 674 rigs at June 30, 2023 and averaged 603 rigs during the second quarter of 2024, compared to 719 rigs in the second quarter of 2023. Similarly, the average number of active drilling rigs in the US decreased by approximately 17% in the first half of 2024 to average 613 rigs compared to 740 rigs in the first half of 2023. In Canada there were 182 active rigs in the Western Canadian Sedimentary Basin ("WCSB") at June 30, 2024, compared to 179 active rigs as at June 30, 2023, representing an increase of approximately 2%, however the CAOEC[4] reported that for drilling in Canada, the total number of Operating Days in the WCSB for the three months ended June 30, 2024, were 8% higher than the same period in the prior year. Similarly, for the six months ended June 30, 2024, the total number of Operating Days in the WCSB were 2% higher than the same period of the prior year.

**Overall Performance and Results of Operations**

Operational results for the three months ended June 30, 2024, include:

- Second quarter revenue of $43.0 million was consistent with the second quarter of 2023. Contract drilling revenue totalled $27.1 million in the second quarter of 2024, which was $3.5 million (or 11%), lower than $30.6 million in the second quarter of 2023. Production services revenue was $16.0 million for the three months ended June 30, 2024, an increase of $3.6 million (or 28%) as compared to $12.4 million in the same period of the prior year. In the second quarter of 2024, revenue in Canada was positively impacted by higher commodity prices, which was offset by lower contract drilling activity in the US, compared to the second quarter of 2023 as described below:
    - In Canada, Operating Days of 656 days in the second quarter of 2024 were 80 days (or 14%) higher compared to 576 days in the second quarter of 2023. Drilling rig utilization in Canada was 21% in the second quarter of 2024, compared to 19% in the same period of the prior year mainly due to improved crude oil prices and some of the Company's drilling rigs working longer into spring break-up than in 2023. The CAOEC industry Operating Days increased by 8% in the second quarter of 2024, compared to the second quarter of 2023, while the CAOEC industry

[3] Source: Baker Hughes Company, 2024 Rig Count monthly press releases.

[4] Source: CAOEC, monthly Contractor Summary.

average utilization increased by five percentage points to 30%[5] for the second quarter of 2024, compared to the CAOEC industry average utilization of 25% in the second quarter of 2023. The increase in the CAOEC industry average utilization is attributable to a 12% decrease in the average number of drilling rigs registered with the CAOEC in the second quarter of 2024 compared to the second quarter of 2023. If the number of registered drilling rigs with the CAOEC had not decreased, the CAOEC industry average utilization in the second quarter of 2024 would have been approximately 27%, two percentage points higher than the second quarter of 2023. Revenue per Operating Day averaged $31,765 in the second quarter of 2024, a decrease of 4% compared to the same period of the prior year, mainly due to lower third party revenue;

  - In the US, drilling rig utilization averaged 24% in the second quarter of 2024, compared to 37% in the second quarter of 2023, with Operating Days decreasing from 267 days in the second quarter of 2023 to 153 days in the second quarter of 2024 due to lower industry activity. Average active industry rigs of 603[6] in the second quarter of 2024 were 16% lower compared to the second quarter of 2023. Revenue per Operating Day for the second quarter of 2024 averaged US$30,016, a 6% decrease compared to US$31,896 in the same period of the prior year, mainly due to higher standby revenue in 2023; and
  - In Canada, service rig utilization was 33% in the second quarter of 2024, compared to 23% in the same period of the prior year, as Service Hours increased by 37% to 13,444 hours from 9,844 hours in the same period of the prior year, due to favorable weather resulting in improved activity. Revenue per Service Hour averaged $1,016 in the second quarter of 2024 and was 3% lower than the second quarter of 2023, due to area specific rig requirements.

- The Company incurred a net loss of $5.1 million in the second quarter of 2024 ($0.15 net loss per basic common share) as compared to a net loss of $7.8 million in the second quarter of 2023 ($0.23 net loss per basic common share). The change can mainly be attributed to a $1.2 million increase in Adjusted EBITDA, a $0.9 million decrease in stock based compensation expense and a $0.4 million decrease in finance costs. Administrative expenses in the second quarter of 2024 were $1.8 million higher than the second quarter of 2023, due to $1.8 million of one-time reorganization costs incurred in 2024.
- Adjusted EBITDA of $5.3 million in the second quarter of 2024 was $1.2 million (or 27%) higher compared to $4.1 million in the second quarter of 2023. The increase in Adjusted EBITDA in the second quarter of 2024 was due to higher drilling and production services revenue in Canada, offset partially by $1.8 million of one-time reorganization costs incurred. Normalizing for the $1.8 million of one-time reorganization costs, Adjusted EBITDA would have totalled $7.1 million for the second quarter of 2024, an increase of 73% from the second quarter of 2023.
- Second quarter additions to property and equipment of $5.6 million in 2024 compared to $6.7 million in the second quarter of 2023, consisting of $4.2 million of expansion capital related to rig upgrades and $1.4 million of maintenance capital.

Operational results for the six months ended June 30, 2024, include:

- Revenue for the six months ended June 30, 2024 decreased by $17.2 million (or 14%), to $105.0 million compared to $122.2 million in the same period of 2023. Contract drilling revenue totalled $66.8 million for the six months ended June 30, 2024, which was $21.9 million (or 25%), lower than $88.7 million in the same period of the prior year. Production services revenue totalled $38.4 million for the six months ended June 30, 2024, an increase of $4.6 million (or 14%) as compared to $33.8 million in the same period of the prior year. In the first half of 2024, revenue was negatively impacted by lower activity in contract drilling in Canada and the US due to lower commodity prices in the first part of 2024, specifically natural gas prices, but positively impacted by higher production services activity in 2024, compared to the first half of 2023 as described below:
  - In Canada, Operating Days of 1,609 days for the six months ended June 30, 2024 were 250 days (or 13%) lower compared to 1,859 days for the six months ended June 30, 2023. Drilling rig utilization in Canada was 26% for the six months ended June 30, 2024, compared to 30% in the same period of the prior year mainly due to customers cancelling or deferring their programs into the second half of 2024, as a result of lower natural gas prices in 2023 that continued into 2024. The CAOEC industry Operating Days increased by 2% in the first half of 2024, compared to the first half of 2023, while the CAOEC industry average utilization increased five percentage points to 40%[5] for the six months ended June 30, 2024, compared to the CAOEC industry average utilization of 35% in the same period of the prior year. The increase in the CAOEC industry average utilization is attributable to a 12% decrease in the average number of drilling rigs registered with the CAOEC in the first half of 2024 compared to the first half of 2023.

[5] Source: CAOEC, monthly Contractor Summary.

[6] Source: Baker Hughes Company, North America Quarterly Rig Count.

If the number of registered drilling rigs with the CAOEC had not decreased, the CAOEC industry average utilization for the six months ended June 30, 2024 would have been approximately 36%, one percentage point higher than the six months ended June 30, 2023. Revenue per Operating Day for the six months ended June 30, 2024 averaged $33,226, which was consistent with the same period of the prior year;

  - In the US, drilling rig utilization averaged 25% for the six months ended June 30, 2024, compared to 41% in the same period of the prior year, with Operating Days decreasing from 594 days in the six months ended June 30, 2023 to 317 days in the same period of 2024 due to lower industry activity. Average active industry rigs of 613[7] for the six months ended June 30, 2024 were 17% lower compared to the six months ended June 30, 2023. Revenue per Operating Day for the six months ended June 30, 2024 averaged US$30,967, a 5% decrease compared to US$32,515 in the same period of the prior year, mainly due to higher standby revenue in 2023; and
  - In Canada, service rig utilization of 38% for the six months ended June 30, 2024 was higher than 33% in the same period of the prior year with Service Hours increasing by 13% from 28,097 hours in 2023 to 31,843 hours in 2024. Revenue per Service Hour averaged $1,040 for the six months ended June 30, 2024 and was consistent with the six months ended June 30, 2023.

- The Company incurred a net loss of $3.7 million for the six months ended June 30, 2024 ($0.11 net loss per basic common share) as compared to a net loss of $3.4 million in the same period in 2023 ($0.10 net loss per basic common share). The change can mainly be attributed to a $1.3 million decrease in stock based compensation expense, a $0.7 million decrease in finance costs, and a $0.4 million increase in income tax recovery, which were partially offset by a $2.8 million decrease in Adjusted EBITDA. Administrative expenses for the six months ended June 30, 2024 were $2.4 million higher than the same period of 2023, due to higher employee related costs including one-time reorganization costs of $1.8 million incurred in 2024.
- Adjusted EBITDA of $20.5 million for the six months ended June 30, 2024 was $2.8 million (or 12%) lower compared to $23.3 million in the same period of 2023 and included one-time reorganization costs of $1.8 million. After normalizing for the one-time reorganization costs, Adjusted EBITDA for the six months ended June 30, 2024 would have totalled $22.3 million, a decrease of $1.0 million (or 4%) from the same period in the prior year. Adjusted EBITDA in 2024 was lower due to lower drilling activity in Canada and the US, as well as lower pricing in the US.
- Year to date 2024 additions to property and equipment of $7.5 million compared to $11.9 million in the same period of 2023, consisting of $4.8 million of expansion capital related to rig upgrades and $2.7 million of maintenance capital.
- On March 22, 2024, the Company extended the maturity of its $35.0 million syndicated revolving credit facility (the "Revolving Facility") and its $10.0 million committed operating facility (the "Operating Facility" and together the "Credit Facilities") from May 18, 2025 to the earlier of (i) six months prior to the maturity date of the Second Lien Facility (as defined in this MD&A) which is currently November 18, 2025, or (ii) March 21, 2027 if the Second Lien Facility is extended. The total commitments under the Credit Facilities are unchanged and there were no changes to the Company's financial covenants, which are described on page 9 under "Liquidity and Capital Resources".

**Outlook**

In 2024, commodity prices are being impacted in the short term by concerns surrounding demand from continued uncertainty concerning the ongoing conflicts in Ukraine and in the Middle East. In addition, OPEC announced a gradual unwinding of production cuts. Events such as these contribute to the volatility of commodity prices. The precise duration and extent of the adverse impacts of the current macroeconomic environment and global economic activity on Western's customers and operations remains uncertain at this time. Additionally, the threatened shutdown and relocation of a portion of the Enbridge Line 5 pipeline and the recent challenge and notice of civil claim related to the Blueberry River First Nations agreement in British Columbia by the Treaty 8 nations, have contributed to continued uncertainty regarding takeaway capacity and resource development. However, the Trans Mountain pipeline expansion commenced operations as of May 1, 2024 bringing much needed takeaway capacity to the market. The Trans Mountain pipeline project, the Coastal GasLink pipeline project, which is mechanically complete and expected to be online in 2025, and the LNG Canada liquefied natural gas project in British Columbia, now more than 85% complete and expected to be online in 2025, may contribute to increased industry activity. Controlling fixed costs, maintaining balance sheet strength and flexibility, repaying debt and managing through a volatile market are priorities for the Company, as prices and demand for Western's services are expected to continue to improve.

As previously announced, Western's board of directors has approved a capital budget for 2024 of $23 million, comprised of $8 million of expansion capital and $15 million of maintenance capital. Western will continue to manage its costs in a

[7] Source: Baker Hughes Company, North America Quarterly Rig Count.

disciplined manner and make required adjustments to its capital program as customer demand changes. Currently, 16 of Western's drilling rigs and 19 of Western's well servicing rigs are operating.

As at June 30, 2024, Western had no amounts drawn on its Credit Facilities and $5.3 million outstanding on its committed term non revolving facility (the "HSBC Facility"), which matures on December 31, 2026. As at June 30, 2024, Western had $98.8 million outstanding on its second lien secured term loan with Alberta Investment Management Corporation (the "Second Lien Facility"), which matures on May 18, 2026. Western will continue to focus its efforts on debt reduction in 2024.

Energy service activity in Canada will be affected by volatile commodity prices, the continued development of resource plays in Alberta and northeast British Columbia, ongoing pipeline completions that will increase takeaway capacity, environmental regulations, and the level of investment in Canada. With Western's upgraded drilling rigs, the Company is well positioned to be the contractor of choice to supply drilling rigs in a tightening market. Western is also active with three fit for purpose drilling rigs in the Clearwater formation in northern Alberta. In the short term, the largest challenges facing the energy service industry are volatile commodity prices and the restrained growth in customer drilling activity due to their continuing preference to return cash to shareholders through share buybacks, increased dividends and repayment of debt, rather than grow production. If commodity prices stabilize for an extended period, then as customers strengthen their balance sheets by reducing debt levels, we expect that drilling activity will increase. In the medium term, Western's rig fleet is well positioned to benefit from the increased drilling and production services activity expected to be generated by the LNG Canada liquefied natural gas project and the Trans Mountain pipeline expansion. The total rig fleet in the WCSB has decreased from 439 drilling rigs at June 30, 2023 to 385 drilling rigs as of July 23, 2024, representing a decrease of 54 drilling rigs, or 12%, which reduces the supply of drilling rigs for such projects. Western is an experienced deep horizontal driller in Canada, with an average well length of 7,550 meters drilled per well and an average of 12.9 Operating Days to drill per well for the six months ended June 30, 2024. It remains Western's view that its upgraded drilling rigs and modern well servicing rigs, reputation for quality and capacity of the Company's rig fleet, and disciplined cash management provides Western with a competitive advantage.

## Review of Results for the Three and Six Months Ended June 30, 2024

### Segmented Information

**Contract Drilling**

| Financial Highlights | Three months ended June 30 | | | Six months ended June 30 | | |
|---|---|---|---|---|---|---|
| (stated in thousands) | 2024 | 2023 | Change | 2024 | 2023 | Change |
| Revenue | 27,149 | 30,586 | (11%) | 66,787 | 88,681 | (25%) |
| Expenses | | | | | | |
| Operating | 21,280 | 25,819 | (18%) | 48,601 | 67,677 | (28%) |
| Administrative | 1,940 | 1,919 | 1% | 4,199 | 3,760 | 12% |
| Adjusted EBITDA(1) | 3,929 | 2,848 | 38% | 13,987 | 17,244 | (19%) |
| Adjusted EBITDA as a percentage of revenue(1) | 14% | 9% | 56% | 21% | 19% | 11% |
| Depreciation | 7,605 | 7,602 | - | 15,542 | 15,141 | 3% |
| Operating earnings (loss) | (3,676) | (4,754) | 23% | (1,555) | 2,103 | (174%) |
| Stock based compensation | (35) | 199 | (118%) | (38) | 423 | (109%) |
| Income (loss) before income taxes | (3,641) | (4,953) | 26% | (1,517) | 1,680 | (190%) |

(1) See "Non-IFRS Measures and Ratios" on page 13 of this MD&A.

For the second quarter of 2024, contract drilling revenue totalled $27.1 million, a $3.5 million, or 11%, decrease as compared to the same period in the prior year. For the six months ended June 30, 2024, contract drilling revenue totalled $66.8 million, a $21.9 million, or 25%, decrease compared to the six months ended June 30, 2023. Contract drilling revenue for both the three and six months ended June 30, 2024, decreased due to lower US activity and pricing throughout the first half of 2024. See "*Canadian Operations*" and "*United States Operations*" below.

Administrative expenses for the second quarter of 2024 totalled $1.9 million and were consistent with the same period in the prior year. For the six months ended June 30, 2024, administrative expenses totalled $4.2 million and were $0.4 million, or 12%, higher than the same period of the prior year. The increase for the six months ended June 30, 2024 was mainly due to severance costs.

Contract drilling incurred a loss before income taxes of $3.6 million in the second quarter of 2024, compared to a loss before income taxes of $5.0 million in the same period of the prior year, a positive change of $1.4 million (or 26%), mainly due to higher Adjusted EBITDA. For the six months ended June 30, 2024, contract drilling incurred a loss before income taxes of $1.5 million, compared to income before income taxes of $1.7 million in the same period of the prior year, a decrease of $3.2

million. The change for the six months ended June 30, 2024, is mainly due to a $3.2 million decrease in Adjusted EBITDA due to lower activity and pricing in the US, which was offset partially by higher activity in Canada.

Contract drilling Adjusted EBITDA of $3.9 million in the second quarter of 2024 was $1.1 million, or 38%, higher than $2.8 million in the second quarter of 2023, mainly due to higher contract drilling activity in Canada and improved profit margins, which was offset partially by lower activity in the US and lower pricing in both the US and Canada. For the six months ended June 30, 2024, contract drilling Adjusted EBITDA of $14.0 million was $3.2 million, or 19%, lower than $17.2 million in the same period of the prior year, mainly due to lower contract drilling activity at the start of 2024 as low commodity prices continued until March 2024, as well as lower pricing in the US.

Depreciation expense for the three and six months ended June 30, 2024 totalled $7.6 million and $15.5 million respectively, compared to $7.6 million and $15.1 million respectively, in the same periods of the prior year. While depreciation was flat quarter over quarter in 2024, the increase for the six months ended June 30, 2024 was mainly due to additions to property and equipment made in prior periods related to the Company’s rig upgrade program.

*Canadian Operations*

The price for WCS improved by 14% from an average of $74.04/bbl in the first six months of 2023 to an average of $84.68/bbl for the first six months of 2024. Operating Days for the second quarter of 2024 of 656 days were 14% higher than 576 days in the same period of the prior year, compared to an 8% increase in industry operating days, resulting in drilling rig utilization in Canada of 21% in 2024, compared to 19% in 2023. The increase in Operating Days for the second quarter of 2024 was mainly attributed to higher crude oil prices, resulting in improved industry activity. However, Operating Days of 1,609 for the six months ended June 30, 2024 were 13% lower than 1,859 days in the same period of the prior year, resulting in drilling rig utilization in Canada of 26% in 2024, compared to 30% in 2023. Lower utilization for the six months ended June 30, 2024, was mainly due to a slower start to 2024 with low commodity prices, specifically natural gas prices, to start the year, resulting in customers cancelling or deferring their programs into the second half of 2024, particularly in northern areas of Alberta.

For the three months ended June 30, 2024, revenue per Operating Day decreased by 4% averaging $31,765 compared to $33,218 in the same period of the prior year, mainly due to lower third party recoveries in 2024. For the six months ended June 30, 2024, revenue per Operating Day averaged $33,226, and was consistent with the same period of the prior year.

*United States Operations*

WTI prices improved by 5% from an average of US$74.97/bbl in the first six months of 2023 to US$78.76/bbl in the first six months of 2024. For the three months ended June 30, 2024, Operating Days in the US decreased by 43% to 153 days compared to 267 days in the same period of the prior year, which resulted in drilling rig utilization of 24% in 2024, compared to 37% in 2023. Similarly, for the six months ended June 30, 2024, Operating Days in the US decreased by 47% to 317 days, compared to 594 days in the same period of the prior year, which resulted in drilling rig utilization of 25% in 2024, compared to 41% utilization in 2023. The decrease in Operating Days for both the three and six months ended June 30, 2024 is due to lower industry activity in the US in 2024, which resulted from low natural gas prices.

For the three and six months ended June 30, 2024, revenue per Operating Day decreased by 6% and 5% averaging US$30,016 and US$30,967 respectively, compared to US$31,896 and US$32,515 in 2023 due to higher standby revenue in 2023.

**Production Services**

| **Financial Highlights** | **Three months ended June 30** | | | **Six months ended June 30** | | |
|---|---|---|---|---|---|---|
| **(stated in thousands)** | **2024** | **2023** | **Change** | **2024** | **2023** | **Change** |
| Revenue | 15,986 | 12,445 | 28% | 38,433 | 33,752 | 14% |
| Expenses | | | | | | |
| Operating | 10,564 | 8,884 | 19% | 25,310 | 23,063 | 10% |
| Administrative | 1,257 | 1,165 | 8% | 2,564 | 2,375 | 8% |
| Adjusted EBITDA(1) | 4,165 | 2,396 | 74% | 10,559 | 8,314 | 27% |
| Adjusted EBITDA as a percentage of revenue(1) | 26% | 19% | 37% | 27% | 25% | 8% |
| Depreciation | 2,125 | 2,202 | (3%) | 4,270 | 4,530 | (6%) |
| Operating earnings | 2,040 | 194 | 952% | 6,289 | 3,784 | 66% |
| Stock based compensation | 35 | 60 | (42%) | 68 | 135 | (50%) |
| Income before income taxes | 2,005 | 134 | 1,396% | 6,221 | 3,649 | 70% |

(1) See "Non-IFRS Measures and Ratios" on page 13 of this MD&A.

For the quarter ended June 30, 2024, production services revenue increased by $3.6 million, or 28%, to $16.0 million, compared to the same period of the prior year. The increase in production services revenue for the three months ended June 30, 2024, was due to higher activity resulting from favorable weather in the quarter. For the six months ended June 30, 2024, production services revenue increased by $4.6 million, or 14%, to $38.4 million, compared to the same period of the prior year. The increase in production services revenue for the six months ended June 30, 2024, compared to the same period in the prior year, can also be attributed to higher utilization as well as higher rentals revenue.

For the three months ended June 30, 2024, Service Hours of 13,444 (33% utilization) were 37% higher than the same period of the prior year of 9,844 (23% utilization). Similarly, for the six months ended June 30, 2024, Service Hours of 31,843 (38% utilization) were 13% higher than the same period of the prior year of 28,097 (33% utilization). For both the three and six months ended June 30, 2024, the increase in Service Hours was due to higher industry activity due in part to favorable weather in the second quarter of 2024. For the three months ended June 30, 2024, revenue per Service Hour averaged $1,016 and was and 3% lower than the same period of 2023 due to area specific rig requirements, whereas for the six months ended June 30, 2024, revenue per Service Hour averaged $1,040 and was consistent with the same period of the prior year.

For the three months ended June 30, 2024, administrative expenses totalled $1.3 million and were $0.1 million, or 8%, higher than the same period of the prior year of $1.2 million. For the six months ended June 30, 2024, administrative expenses totalled $2.6 million and were $0.2 million, or 8%, higher than the same period of the prior year of $2.4 million. The increase for both the three and six months ended June 30, 2024 was due to higher professional fees.

For the second quarter of 2024, production services generated income before income taxes of $2.0 million, compared to income before income taxes of $0.1 million in the same period of the prior year, mainly due to a $1.8 million increase in Adjusted EBITDA. For the six months ended June 30, 2024, production services generated income before income taxes of $6.2 million, compared to income before income taxes of $3.6 million in the same period of 2023, mainly due to a $2.3 increase in Adjusted EBITDA.

Adjusted EBITDA increased for the three months ended June 30, 2024, by $1.8 million, or 74%, to $4.2 million, compared to $2.4 million in the same period of the prior year. Adjusted EBITDA increased for the six months ended June 30, 2024 by $2.3 million, or 27%, to $10.6 million, compared to $8.3 million in the same period of 2023. The increase for both the three and six months ended June 30, 2024 is due to higher well servicing utilization and higher rentals activity.

Depreciation expense for the three and six months ended June 30, 2024 was 3% and 6% lower respectively, than the same periods of the prior year, as additions to property and equipment were offset by certain assets being fully depreciated in the period.

**Corporate**

| | Three months ended June 30 | | | Six months ended June 30 | | |
|---|---|---|---|---|---|---|
| **(stated in thousands)** | **2024** | **2023** | **Change** | **2024** | **2023** | **Change** |
| Expenses | | | | | | |
| Administrative | 2,835 | 1,104 | 157% | 4,068 | 2,222 | 83% |
| Depreciation | 345 | 448 | (23%) | 786 | 877 | (10%) |
| Operating loss | (3,180) | (1,552) | (105%) | (4,854) | (3,099) | (57%) |
| Stock based compensation | (161) | 503 | (132%) | 246 | 1,080 | (77%) |
| Finance costs | 2,494 | 2,879 | (13%) | 5,150 | 5,921 | (13%) |
| Other items | (392) | (78) | 403% | (772) | (684) | 13% |
| Income tax recovery | (1,621) | (1,830) | (11%) | (1,093) | (663) | 65% |

For the three months ended June 30, 2024, corporate administrative expenses totalled $2.8 million and were $1.7 million higher than the same period of the prior year. Similarly, for the six months ended June 30, 2024, corporate administrative expenses totalled $4.1 million and were $1.9 million, or 83%, higher than the same period of the prior year. The increase for both the three and six months ended June 30, 2024 is mainly due to $1.8 million of one-time reorganization costs incurred in 2024.

Finance costs in the second quarter of 2024 of $2.5 million were $0.4 million lower than the same period of the prior year, mainly due to lower total debt levels resulting from Western's debt repayments made in 2023 and 2024, and represented an effective interest rate of 8.6%, which was slightly lower than 8.7% in the same period of the prior year. The lower effective interest rate for the three months ended June 30, 2024 was due to the Bank of Canada decreasing its prime interest rate in June 2024 by 0.25 percentage points to 6.95%, which impacted the Company's floating interest rate debt. For the six months ended June 30, 2024, finance costs of $5.2 million were $0.7 million lower than the same period of the prior year, mainly due to lower total debt levels and represented an effective interest rate of 8.7%, which was consistent with 8.7% in 2023.

Other items, which relate to foreign exchange gains and losses and the sale of assets, totalled a gain of $0.4 million and $0.8 million for the three and six months ended June 30, 2024 respectively, compared to a gain of $0.1 million and $0.7 million respectively, in the same periods of the prior year. During the six months ended 2024, the Company sold two well servicing rig carriers for total proceeds of US$0.9 million and recognized a gain on sale of fixed assets of $0.2 million.

For the second quarter of 2024, the consolidated income tax recovery totalled $1.6 million, representing an effective tax rate of 24.0%, as compared to an effective tax rate of 18.9% in the same period of the prior year. For the six months ended June 30, 2024, the consolidated income tax recovery totalled $1.1 million, representing an effective tax rate of 22.9%, as compared to an effective tax rate of 16.2% in the same period of the prior year. The Company had no cash taxes payable for the three and six months ended June 30, 2024 or 2023.

**Liquidity and Capital Resources**

The Company's liquidity requirements in the short and long term can be sourced in several ways including: available cash balances, funds from operations, borrowing against the Credit Facilities, new debt instruments, equity issuances and proceeds from the sale of assets. As at June 30, 2024, Western had working capital of $22.2 million compared to working capital of $20.1 million as at December 31, 2023.

During the six months ended June 30, 2024, Western had the following changes to its cash balances, which resulted in a $9.6 million increase in cash and cash equivalents in the period:

| **Cash and cash equivalents (stated in thousands)** | |
|---|---|
| Opening balance, at December 31, 2023 | 5,930 |
| Add: | |
| Adjusted EBITDA[1] | 20,478 |
| Change in non cash working capital | 8,475 |
| Proceeds on sale of property and equipment | 1,520 |
| Deduct: | |
| Additions to property and equipment | (7,537) |
| Finance costs paid | (5,407) |
| Repayment of Credit Facilities | (5,000) |
| Principal repayment of lease obligations | (1,278) |
| Principal repayment of HSBC Facility | (625) |
| Principal repayment of Second Lien debt | (540) |
| Principal repayment of US paycheck protection plan | (480) |
| Other items | (1) |
| **Ending balance, at June 30, 2024** | **15,535** |

(1) See "Non-IFRS Measures and Ratios" on page 13 of this MD&A.

On March 22, 2024, the Company extended the maturity of its Credit Facilities from May 18, 2025 to the earlier of (i) six months prior to the maturity date of the Second Lien Facility which is currently November 18, 2025, or (ii) March 21, 2027 if the Second Lien Facility is extended. The total commitment of $45.0 million under the Credit Facilities is unchanged and there were no changes to the Company's financial covenants. As at June 30, 2024, no amounts were drawn on the Credit Facilities and $5.3 million was drawn on the HSBC Facility. Cash flow from operations and available Credit Facilities are expected to be sufficient to cover Western's financial obligations, including working capital requirements and budgeted 2024 capital expenditures.

Amounts borrowed under the Credit Facilities bear interest at the bank's Canadian prime rate or daily compounded Canadian overnight repo rate average ("CORRA"), as applicable, for borrowings in Canadian dollars, plus in each case an applicable margin depending on the ratio of Consolidated Debt to Consolidated EBITDA as defined by the Credit Facilities agreement. Consolidated EBITDA, as defined by the Credit Facilities agreement, differs from Adjusted EBITDA as defined under Non-IFRS Measures and Ratios on page 13 of this MD&A, by including certain items such as realized foreign exchange gains or losses and cash payments made on leases capitalized under IFRS 16 Leases. Copies of Western's Credit Facilities are available under the Company's SEDAR+ profile at www.sedarplus.ca.

The Credit Facilities are secured by the assets of Western and its subsidiary. A summary of the Company's financial covenants at June 30, 2024 is as follows:

| June 30, 2024 | Covenants [1] |
|---|---|
| Maximum Consolidated Senior Debt to Consolidated EBITDA Ratio | 3.0:1.0 or less |
| Maximum Consolidated Debt to Consolidated Capitalization Ratio | 0.5:1.0 or less |
| Minimum Debt Service Coverage Ratio | 1.15:1.0 or greater |

(1) See covenant definitions in Note 7 of the June 30, 2024 condensed consolidated financial statements.

At June 30, 2024, Western was in compliance with all covenants related to its Credit Facilities.

**Summary of Quarterly Results**

In addition to other market factors, Western's quarterly results 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" when, 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 quarter over quarter, particularly between the first and second quarters, can be significant 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) | June 30,<br>2024 | Mar 31,<br>2024 | Dec 31,<br>2023 | Sep 30,<br>2023 | June 30,<br>2023 | Mar 31,<br>2023 | Dec 31,<br>2022 | Sep 30,<br>2022 |
|---|---|---|---|---|---|---|---|---|
| Revenue | 43,033 | 61,982 | 56,255 | 55,003 | 42,954 | 79,239 | 60,792 | 58,483 |
| Adjusted EBITDA[1] | 5,259 | 15,219 | 13,370 | 11,033 | 4,140 | 19,196 | 12,233 | 14,799 |
| Cash flow from operating activities | 19,260 | 7,802 | 6,268 | 13,267 | 25,373 | 6,445 | 6,502 | 6,854 |
| Net income (loss) | (5,136) | 1,455 | (2,194) | (1,267) | (7,845) | 4,421 | (3,095) | 818 |
| per share - basic and diluted | (0.15) | 0.04 | (0.06) | (0.04) | (0.23) | 0.13 | (0.09) | 0.02 |
| Total assets | 433,354 | 441,781 | 442,933 | 453,980 | 456,746 | 483,532 | 475,708 | 475,651 |
| Long term debt - non current portion | 106,912 | 111,109 | 111,174 | 114,107 | 118,109 | 129,853 | 126,527 | 127,639 |

(1) See "Non-IFRS Measures and Ratios" on page 13 of this MD&A.

Revenue and Adjusted EBITDA were impacted by commodity prices and market uncertainty throughout the last eight quarters. Crude oil prices were high in 2022 due to the conflict in Ukraine, resulting in improvements in pricing and activity throughout the industry. 2023 was impacted by a significant decrease in commodity prices, the fear of a North American recession, concerns surrounding demand for crude oil due to weak global economic data, as well as the ongoing conflicts in Ukraine and in the Middle East. The first quarter of 2024 was impacted by low commodity prices, resulting in volatility with customer programs and lower industry activity, however the second quarter of 2024 experienced improved commodity prices leading to improved activity in Canada.

**Commitments**

In the normal course of business, the Company incurs commitments related to its contractual obligations. The expected maturities of the Company's contractual obligations as at June 30, 2024 are as follows:

| (stated in thousands) | 2024 | 2025 | 2026 | 2027 | 2028 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Trade payables and other current liabilities (1) | 19,327 | - | - | - | - | - | 19,327 |
| Operating commitments (2) | 5,750 | 452 | 762 | 762 | 762 | 1,143 | 9,631 |
| Second Lien Facility principal | 540 | 1,080 | 97,181 | - | - | - | 98,801 |
| Second Lien Facility interest | 4,193 | 8,341 | 6,854 | - | - | - | 19,388 |
| HSBC Facility principal | - | - | 5,313 | - | - | - | 5,313 |
| HSBC Facility interest | 241 | 389 | 270 | - | - | - | 900 |
| Lease obligations (3) | 1,551 | 1,625 | 1,440 | 975 | 744 | 1,119 | 7,454 |
| PPP Loan | 552 | 798 | - | - | - | - | 1,350 |
| **Total** | **32,154** | **12,685** | **111,820** | **1,737** | **1,506** | **2,262** | **162,164** |

(1) Trade payables and other current liabilities exclude interest accrued as at June 30, 2024 on the Second Lien Facility and the HSBC Facility which are stated separately.

(2) Operating commitments include purchase commitments, short term operating leases, and operating expenses associated with long term leases.

(3) Lease obligations represent the gross lease commitments to be paid over the term of the Company's outstanding long term leases.

*Trade payables and other current liabilities:*

The Company has recorded trade payables for amounts due to third parties which are expected to be paid within one year.

*Operating commitments:*

The Company has agreements in place to purchase certain capital and other operational items with third parties, as well as short term leases with a term of less than one year, and operating expenses associated with long term leases.

*Second Lien Facility principal and interest:*

The Company pays principal quarterly and interest semi-annually on January 1 and July 1. The Company's Second Lien Facility matures on May 18, 2026.

*HSBC Facility principal and interest:*

The Company pays interest monthly on the HSBC Facility, which matures on December 31, 2026.

*Lease obligations:*

The Company has long term debt relating to leased vehicles, as well as office and equipment leases. These leases run for terms greater than one year.

*PPP loan:*

The Company has a US Paycheck Protection Program ("PPP") loan obtained as part of the COVID-19 relief efforts in the US. The promissory loan has an interest rate of 1% per annum, will be repaid in equal monthly payments over the term of the loan and matures on August 7, 2025.

Western expects to source funds required for the above commitments from cash flow from operations.

**Outstanding Share Data**

| | July 23, 2024 | June 30, 2024 | December 31, 2023 |
|---|---|---|---|
| Common shares outstanding | 33,843,022 | 33,843,015 | 33,843,009 |
| Stock options outstanding | 2,324,814 | 2,506,597 | 3,052,700 |
| Restricted share units outstanding - equity settled | - | 7 | 13 |

**Off Balance Sheet Arrangements**

As at June 30, 2024, Western had no off balance sheet arrangements in place.

**Financial Risk Management**

*Interest Risk*

The Company is exposed to interest rate risk on certain debt instruments, such as the Credit Facilities and the HSBC Facility, to the extent the prime or CORRA interest rate changes and/or the Company's interest rate margin changes. Other long term debt, such as the Second Lien Facility, PPP loan and the Company's lease obligations, have fixed interest rates, however they are subject to interest rate fluctuations relating to refinancing.

*Inflation Risk*

The general rate of inflation impacts the economies and business environments in which Western operates. Increased inflation and any economic conditions resulting from governmental attempts to reduce inflation, such as the imposition of higher interest rates, could negatively impact Western's borrowing costs, which could, in turn, have a material adverse effect on Western's cash flow and ability to service obligations under the Credit Facilities, HSBC Facility and the Second Lien Facility.

*Foreign Exchange Risk*

The Company is exposed to foreign currency fluctuations in relation to its US dollar capital expenditures and operations. At June 30, 2024, portions of the Company's cash balances, trade and other receivables, trade payables and other current liabilities were denominated in US dollars and subject to foreign exchange fluctuations which are recorded within net income (loss). In addition, Stoneham, Western's US subsidiary, is subject to foreign currency translation adjustments upon consolidation, which is recorded separately within other comprehensive income.

*Credit Risk*

Credit risk arises from cash and cash equivalents held with banks and financial institutions, as well as credit exposure to customers in the form of outstanding trade and other receivables. The maximum exposure to credit risk is equal to the carrying amount of the financial assets which reflects management's assessment of the credit risk.

The Company's trade receivables are with customers in the energy industry and are subject to industry credit risk. For the three and six months ended June 30, 2024, the volatility in global demand for crude oil related to the conflicts in Ukraine and the Middle East, have had an impact on commodity prices which have an effect on the Company's customers. These factors are expected to have an impact on companies and their related credit risk. The Company's practice is to manage credit risk by performing a thorough analysis of the creditworthiness of new customers before credit terms are offered.

Additionally, the Company continually evaluates individual customer trade receivables for collectability considering payment history and aging of the trade receivables.

In accordance with IFRS 9, Financial Instruments, the Company evaluates the collectability of its trade and other receivables and its allowance for doubtful accounts at each reporting date. The Company records an allowance for doubtful accounts if an account is determined to be uncollectable. The allowance for doubtful accounts could materially change due to fluctuations in the financial position of the Company's customers.

The Company reviews its historical credit losses as part of its impairment assessment. The Company has had low historical impairment losses on its trade receivables, due in part to its credit management processes. As such, the Company assesses impairment losses on an individual customer account basis, rather than recognizing an impairment loss on all outstanding trade and other receivables.

*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. The Company manages liquidity risk through management of its capital structure, monitoring and reviewing actual and forecasted cash flows and the effect on bank covenants and maintaining unused credit facilities where possible to ensure there are available cash resources to meet the Company's liquidity needs. The Company's cash and cash equivalents, cash from operating activities, the Credit Facilities, the HSBC Facility, and the Second Lien Facility are expected to be greater than anticipated capital expenditures and the contractual maturities of the Company's financial liabilities. This expectation could be adversely affected by a material negative change in the energy service industry, which in turn could lead to covenant breaches on the Company's Credit Facilities, which if not amended or waived, could limit, in part, or in whole, the Company's access to the Credit Facilities and Second Lien Facility.

**Disclosure Controls and Procedures and Internal Controls Over Financial Reporting**

As Western's common shares trade on the Toronto Stock Exchange, pursuant to National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, the President and Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") of the Company have certified as at June 30, 2024 that they have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") to provide reasonable assurance that: (i) material information relating to the Company, including its consolidated subsidiary, is made known to the CEO and the CFO by others within those entities, particularly during the periods in which the interim filings of the Company are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

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

During the three months ended June 30, 2024, there were no changes in internal control over financial reporting that materially affected, or are reasonably likely to materially affect, Western's internal control over financial reporting.

**Critical Accounting Estimates and Recent Developments**

The accounting policies used in preparing the Company's financial statements are described in Note 2 of the Company's condensed consolidated financial statements as at June 30, 2024 and for the three and six months ended June 30, 2024 and 2023. There were no new accounting standards or amendments to existing standards adopted in the three and six months ended June 30, 2024, that are expected to have a material impact on the Company's financial statements.

This MD&A of the Company's financial condition and results of operations is based on the condensed consolidated financial statements as at and for the three and six months ended June 30, 2024, which were prepared in accordance with IFRS. Conformity with IFRS requires management to make judgments, estimates and assumptions that are based on the facts, circumstances, and estimates at the date of the consolidated financial statements and affect the application of certain accounting policies and the reported amount of assets, liabilities, income and expenses.

The current economic environment and volatility in global demand for commodities results in uncertainty for the Company, which management took into consideration when applying judgments to estimates and assumptions in the condensed consolidated financial statements. A full list of critical accounting estimates is included in the Company's audited consolidated financial statements for the year ended December 31, 2023. Actual results may differ from the estimates used in preparing the consolidated financial statements.

**Business Risks**

Management has identified the primary risk factors that could potentially have a material impact on the financial results and operations of Western. Western's primary risk factors are included in the Company's annual information form ("AIF") for the year ended December 31, 2023 which is available under the Company's SEDAR+ profile at www.sedarplus.ca. Copies of the AIF may also be obtained on request without charge from Western by emailing ir@wesc.ca or through Western's website at www.wesc.ca.

**Non-IFRS Measures and Ratios**

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

*Adjusted EBITDA and Adjusted EBITDA as a Percentage of Revenue*

Adjusted 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 non-GAAP financial measure as it is used by management and other stakeholders, including current and potential investors, to analyze the Company's principal business activities, prior to consideration of how Western's activities are financed and the impact of foreign exchange, income taxes and depreciation. Adjusted EBITDA provides an indication of the results generated by the Company's principal operating segments, which assists management in monitoring current and forecasting future operations, as certain non-core items such as interest and finance costs, taxes, depreciation and amortization, and other non-cash items and one-time gains and losses are removed. The closest IFRS measure would be net income for consolidated results and on a segmented basis, income before income taxes, as the Company manages its income tax position on a legal entity basis, which can differ from its operating segments.

Adjusted EBITDA as a percentage of revenue is a non-IFRS financial ratio which is calculated by dividing Adjusted EBITDA by revenue for the relevant period. Adjusted EBITDA as a percentage of revenue is a useful financial measure as it is used by management and other stakeholders, including current and potential investors, to analyze the profitability of the Company's principal operating segments.

The following table provides a reconciliation of net loss, as disclosed in the condensed consolidated statements of operations and comprehensive loss, to Adjusted EBITDA:

| | Three months ended June 30 | | Six months ended June 30 | |
|---|---|---|---|---|
| **(stated in thousands)** | **2024** | **2023** | **2024** | **2023** |
| **Net loss** | **(5,136)** | **(7,845)** | **(3,681)** | **(3,424)** |
| Income tax recovery | (1,621) | (1,830) | (1,093) | (663) |
| **Loss before income taxes** | **(6,757)** | **(9,675)** | **(4,774)** | **(4,087)** |
| Add (deduct): | | | | |
| Depreciation | 10,075 | 10,252 | 20,598 | 20,548 |
| Stock based compensation | (161) | 762 | 276 | 1,638 |
| Finance costs | 2,494 | 2,879 | 5,150 | 5,921 |
| Other items | (392) | (78) | (772) | (684) |
| **Adjusted EBITDA** | **5,259** | **4,140** | **20,478** | **23,336** |

*Revenue per Operating Day*

This non-IFRS measure is calculated as drilling revenue for both Canada and the US respectively, divided by Operating Days in Canada and the US respectively. This calculation represents the average day rate by country, charged to Western's customers.

*Revenue per Service Hour*

This non-IFRS measure is calculated as well servicing revenue divided by Service Hours. This calculation represents the average hourly rate charged to Western's customers.

*Working Capital*

This non-IFRS measure is calculated as current assets less current liabilities as disclosed in the Company's consolidated financial statements.

**Defined Terms**

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

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

*Average meters drilled per well:* Defined as total meters drilled divided by the number of wells completed in the period.

*Average Operating Days per well:* Defined as total Operating Days divided by the number of wells completed in the period.

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

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

*Service Hours:* Defined as well servicing hours completed.

*Service rig utilization:* Calculated as total Service Hours divided by 217 hours per month per rig multiplied by the average rig count for the period as defined by the CAOEC industry standard.

**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");
- Canadian Association of Energy Contractors ("CAOEC");
- DecaNewton ("daN");

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

**Forward-Looking Statements and Information**

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

In particular, forward-looking information in this MD&A includes, but is not limited to, statements relating to: the business of Western, industry, market and economic conditions and any anticipated effects on Western and its customers; commodity pricing; the future demand for the Company's services and equipment; the effect of inflation and commodity prices on energy service activity; expectations with respect to customer spending; the expected impact of Western's recently upgraded drilling rigs; the potential continued impact of the current conflicts in Ukraine and the Middle East on crude oil prices; the Company's capital budget for 2024 including the allocation of such budget; Western's plans for managing its capital program; the energy service industry and global economic activity; expectations of increased takeaway capacity with respect to the completion of the Trans Mountain pipeline expansion; the potential shutdown and relocation of the Enbridge Line 5 pipeline; expectations with respect to the Coastal GasLink pipeline project and LNG Canada facility; the impact of the recent challenge and notice of civil claim related to the Blueberry River First Nations decision by the Treaty 8 nations; challenges facing the energy service industry; expectations regarding future drilling and well servicing activity; expectations that cancelled or deferred customer programs will go forward in the second half of 2024; the Company's focus on debt reduction; the Company's ability to source its short and long term liquidity requirements; the Company's liquidity needs including the ability of current capital resources to cover Western's financial obligations; expectations with respect to capital expenditures; the methods by which the Company manages liquidity risk; the use, availability and sufficiency of the Company's Credit Facilities; the Company's ability to maintain certain covenants under its Credit Facilities; the repayment of the Company's debt, including the source of funds required to repay such debt; maturities of the Company's contractual obligations with third parties; the impact of changes in interest rates and foreign exchange rates; estimates with respect to foreign exchange rates; factors affecting companies with credit risk; the expectation of continued investment in the Canadian crude oil and natural gas industry; the development of Alberta and British Columbia resource plays; expectations relating to the increase in takeaway capacity resulting from ongoing pipeline completions; expectations relating to activity levels for oilfield services; expectations with respect to increased drilling activity; the Company's ability to maintain a competitive advantage, including the factors and practices anticipated to produce and sustain such advantage; and forward-looking information contained under the headings "*Disclosure Controls and Procedures and Internal Controls Over Financial Reporting*", "*Business Risks*", "*Financial Risk Management"* and "*Critical Accounting Estimates and Recent Developments*".

The material assumptions that could cause results or events to differ from current expectations reflected in the forward-looking information in this MD&A include, but are not limited to: demand levels and pricing for oilfield services; demand for crude oil and natural gas and the price and volatility of crude oil and natural gas; pressures on commodity pricing; the impact of inflation; the continued business relationships between the Company and its significant customers; crude oil transport, pipeline and LNG export facility approval and development; that all required regulatory and environmental approvals can be obtained on the necessary terms and in a timely manner, as required by the Company; liquidity and the Company's ability to finance its operations; the effectiveness of the Company's cost structure and capital budget; the effects of seasonal and weather conditions on operations and facilities; the competitive environment to which the various business segments are, or may be, exposed in all aspects of their business and the Company's competitive position therein; the ability of the Company's various business segments to access equipment (including spare parts and new technologies); global economic conditions and the accuracy of the Company's market outlook expectations for 2024 and in the future; the impact, direct and indirect, of epidemics, pandemics, other public health crisis and geopolitical events, including the conflicts in Ukraine and the Middle East, on Western's business, customers, business partners, employees, supply chain, other stakeholders and the overall economy; changes in laws or regulations; currency exchange fluctuations; the ability of the Company to attract and retain skilled labour and qualified management; the ability to retain and attract significant customers; the ability to maintain a satisfactory safety record; that any required commercial agreements can be reached; that there are no unforeseen events preventing the performance of contracts and general business, economic and market conditions.

Although Western believes that the expectations and assumptions on which such forward-looking information is based on are reasonable, undue reliance should not be placed on the forward-looking information as Western cannot give any assurance that such will prove to be correct. By its nature, forward-looking information is subject to 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, volatility in market prices for crude oil and natural gas and the effect of this volatility on the demand for oilfield services generally; reduced exploration and development activities by customers and the effect of such reduced activities on Western's services and products; political, industry, market, economic, and environmental conditions in Canada, the US, and globally; supply and demand for oilfield services relating to contract drilling, well servicing and oilfield rental equipment services; the proximity, capacity and accessibility of crude oil and natural gas pipelines and processing facilities; liabilities and risks inherent in oil and natural gas operations, including environmental liabilities and risks; changes to laws, regulations and policies; the ongoing geopolitical events in Eastern Europe and the Middle East and the duration and impact thereof; fluctuations in foreign exchange or interest rates; failure of counterparties to perform or comply with their obligations under contracts; regional competition and the increase in new or upgraded rigs; the Company's ability to attract and retain skilled labour; Western's ability to obtain debt or equity financing and to fund capital operating and other expenditures and obligations; the potential need to issue additional debt or equity and the potential resulting dilution of shareholders; uncertainties in weather and temperature affecting the duration of the service periods and the activities that can be completed; the Company's ability to comply with the covenants under the Credit Facilities, HSBC Facility and the Second Lien Facility and the restrictions on its operations and activities if it is not compliant with such covenants; Western's ability to protect itself from "cyber-attacks" which could compromise its information systems and critical infrastructure; disruptions to global supply chains; and other general industry, economic, market and business conditions. Readers are cautioned that the foregoing list of risks, uncertainties and assumptions are not exhaustive. Additional information on these and other risk factors that could affect Western's operations and financial results are discussed under the headings "*Business Risks*" herein and "*Risk Factors*" in Western's AIF for the year ended December 31, 2023, which is available under the Company's SEDAR+ profile at www.sedarplus.ca.

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. Any forward-looking statements contained herein are expressly qualified by this cautionary statement.

**Additional data**

Additional information relating to Western, including the Company's AIF, is available under the Company's profile on SEDAR+ at www.sedarplus.ca.