Western ENERGY SERVICES CORP.

Q3 2025

Third Quarter 2025 Management's Discussion and Analysis — Date: October 21, 2025

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 as at and for the years ended December 31, 2024 and 2023, management's discussion and analysis ("MD&A") for the year ended December 31, 2024, as well as the condensed consolidated financial statements and notes as at September 30, 2025 and for the three and nine months ended September 30, 2025 and 2024. This MD&A is dated October 21, 2025. All amounts are denominated in Canadian dollars (CDN$) unless otherwise identified.

Financial Highlights	**Three months ended September 30**			**Nine months ended September 30**		
(stated in thousands, except share and per share amounts)	**2025**	**2024**	**Change**	**2025**	**2024**	**Change**
Revenue	50,035	58,343	(14%)	159,050	163,358	(3%)
Adjusted EBITDA[1]	13,062	11,433	14%	32,991	31,911	3%
Adjusted EBITDA as a percentage of revenue[1]	26%	20%	30%	21%	20%	5%
Cash flow from operating activities	8,452	5,404	56%	30,934	32,466	(5%)
Additions to property and equipment	5,465	8,223	(34%)	16,398	15,760	4%
Net loss	(2,242)	(1,190)	(88%)	(4,441)	(4,871)	9%
-basic and diluted net loss per share	(0.07)	(0.04)	(75%)	(0.13)	(0.14)	7%
Weighted average number of shares						
-basic and diluted	33,843,022	33,843,022	-	33,843,022	33,843,017	-
Outstanding common shares as at period end	33,843,022	33,843,022	-	33,843,022	33,843,022	-
Operating Highlights[2]						
Contract Drilling						
Canadian Operations						
Operating Days	1,022	1,115	(8%)	3,099	2,724	14%
Revenue per Operating Day[1]	30,425	31,141	(2%)	32,344	32,373	-
Drilling rig utilization	33%	36%	(8%)	33%	29%	14%
CAOEC industry Operating Days[3]	15,097	17,398	(13%)	43,744	45,761	(4%)
United States Operations						
Operating Days	146	229	(36%)	423	546	(23%)
Revenue per Operating Day (US$)[1]	33,669	28,429	18%	31,108	29,904	4%
Drilling rig utilization	24%	36%	(33%)	22%	28%	(21%)
Production Services						
Service Hours	9,838	12,525	(21%)	31,946	44,368	(28%)
Revenue per Service Hour[1]	950	979	(3%)	1,021	1,023	-
Service rig utilization	24%	31%	(23%)	26%	36%	(28%)

(1) See "Non-IFRS Measures and Ratios" on page 14 of this MD&A.

(2) See "Defined Terms" on page 15 of this MD&A.

(3) Source: The Canadian Association of Energy Contractors ("CAOEC") monthly Contractor Summary, calculated on a spud to rig release basis.

Financial Position at (stated in thousands)	**September 30, 2025**	**December 31, 2024**	**September 30, 2024**
Working capital[1]	19,418	9,911	17,697
Total assets	405,949	430,981	429,623
Long-term debt - non current portion	90,445	91,657	102,999

(1) See "Defined Terms" on page 15 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, and revenue per Service Hour are defined on page 14 of this MD&A. Other defined terms, abbreviations and definitions for standard industry terms are included on page 15 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 40 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 September 30					
	2025			2024		
Rig class(1)	Canada	US	Total	Canada	US	Total
Cardium	11	-	11	11	-	11
Montney	18	-	18	18	1	19
Duvernay	5	6	11	5	6	11
Total marketed drilling rigs(2)	**34**	**6**	**40**	**34**	**7**	**41**
Total owned drilling rigs	**48**	**6**	**54**	**48**	**7**	**55**

(1) See "Contract Drilling Rig Classifications" on page 15 of this MD&A.
(2) Source: CAOEC Contractor Summary as at October 21, 2025.

Production Services

Production services provides well servicing and oilfield equipment rentals in Canada. Western operates 62 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 September 30	
Mast type	**2025**	**2024**
Single	27	28
Double	27	27
Slant	8	8
Total owned well servicing rigs	**62**	**63**

[1] Source: CAOEC Drilling Contractor Summary as at October 21, 2025.
[2] Source: CAOEC Well Servicing Fleet List as at October 21, 2025.

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 nine months ended September 30, 2025 and 2024:

	Three months ended September 30			Nine months ended September 30		
	2025	**2024**	**Change**	**2025**	**2024**	**Change**
Average crude oil and natural gas prices(1)(2)						
Crude Oil						
West Texas Intermediate (US$/bbl)	64.93	75.13	(14%)	66.70	77.55	(14%)
Western Canadian Select (CDN$/bbl)	74.95	84.93	(12%)	78.09	84.76	(8%)
Natural Gas						
30 day Spot AECO (CDN$/mcf)	0.63	0.73	(14%)	1.55	1.40	11%
Average foreign exchange rates(2)						
US dollar to Canadian dollar	1.38	1.36	1%	1.40	1.36	3%

(1) See "Abbreviations" on page 15 of this MD&A.

(2) Source: Sproule September 30, 2025, Price Forecast, Historical Prices.

- West Texas Intermediate ("WTI") on average decreased by 14% for both the three and nine months ended September 30, 2025 respectively, compared to the same periods in the prior year. In 2025, crude oil prices were impacted by market volatility due to tariffs implemented by the US government, counter-tariffs in response by several countries, lower global demand and the continued conflict in the Middle East and Eastern Europe.
- Pricing on Western Canadian Select crude oil declined by 12% and 8% for the three and nine months ended September 30, 2025 respectively, compared to the same periods of the prior year.
- Natural gas prices in Canada were lower for the three months ended September 30, 2025, as the 30-day spot AECO price decreased by 14% compared to the same period of the prior year; however, for the nine months ended September 30, 2025, the 30-day spot AECO price increased by 11%, compared to the same period in the prior year.
- The US dollar to the Canadian dollar foreign exchange rate for the three and nine months ended September 30, 2025, strengthened by 1% and 3% respectively, compared to the same periods in the prior year.
- Lower WTI prices in the nine months ended September 30, 2025, contributed to weaker industry drilling activity in the US. As reported by Baker Hughes Company[3], the number of active drilling rigs in the US decreased by approximately 8% to 540 rigs as at September 30, 2025 as compared to 587 rigs at September 30, 2024, and averaged 566 rigs during the nine months ended September 30, 2025, compared to 604 rigs in the same period of the prior year.
- In Canada there were 196 active rigs in the Western Canadian Sedimentary Basin ("WCSB") at September 30, 2025, compared to 223 active rigs as at September 30, 2024, representing a decrease of approximately 12%. The CAOEC[4] reported that for drilling in Canada, the total number of Operating Days in the WCSB for the three months ended September 30, 2025, were 13% lower than the same period in the prior year, whereas the total number of Operating Days in the WSCB for the nine months ended September 30, 2025, were 4% lower than the same period of the prior year.

Operational and Financial Highlights

Three Months Ended September 30, 2025

Financial Highlights:

- Third quarter revenue of $50.0 million in 2025 was $8.3 million (or 14%) lower than the third quarter of 2024, due to lower activity in both the contract drilling and well servicing segments.
- Adjusted EBITDA of $13.1 million in the third quarter of 2025 was $1.7 million (or 14%) higher compared to $11.4 million in the third quarter of 2024, despite third quarter revenue decreasing by 14% compared to the same period in the prior year. There were no one-time reorganization costs incurred in the third quarter of 2025, whereas the third quarter of 2024 had one-time reorganization costs of $0.6 million.
- The Company incurred a net loss of $2.2 million in the third quarter of 2025 ($0.07 net loss per basic common share) as compared to a net loss of $1.2 million in the third quarter of 2024 ($0.04 net loss per basic common share) as a $3.0

[3] Source: Baker Hughes Company, 2025 Rig Count monthly press releases.

[4] Source: CAOEC, monthly Contractor Summary.

million higher loss on the sale of fixed assets and higher depreciation expense, were offset partially by higher Adjusted EBITDA, lower finance costs and an increase in income tax recovery.

- Third quarter additions to property and equipment of $5.5 million in 2025 compared to $8.2 million in the third quarter of 2024, consisting of $2.1 million of expansion capital related to rig upgrades and $3.4 million of maintenance capital.

Operational Highlights:

- In Canada, Operating Days of 1,022 in the third quarter of 2025 were 93 days (or 8%) lower compared to 1,115 days in the third quarter of 2024. Drilling rig utilization in Canada was 33% in the third quarter of 2025, compared to 36% in the same period of the prior year, mainly due to continued weak commodity prices, impacting customer drilling programs.
- Revenue per Operating Day in Canada averaged $30,425 in the third quarter of 2025, which was 2% lower than the same period of the prior year.
- In the US, drilling rig utilization averaged 24% in the third quarter of 2025, which was lower than the third quarter of 2024, due to continued low industry activity in the US as well as a change in focus to North Dakota from Texas.
- Revenue per Operating Day in the US for the third quarter of 2025 averaged US$33,669, an 18% increase compared to US$28,429 in the same period of the prior year. The improvement in pricing reflects a more favorable rig mix following the Company's strategic decision to focus its US operations more in North Dakota.
- In Canada, service rig utilization was 24% in the third quarter of 2025, compared to 31% in the same period of the prior year, as Service Hours decreased by 21% to 9,838 hours from 12,525 hours in the same period of the prior year, mainly due to changes in customer programs.
- Revenue per Service Hour averaged $950 in the third quarter of 2025 and was 3% lower than the third quarter of 2024.

Nine Months Ended September 30, 2025

Financial Highlights:

- Revenue for the nine months ended September 30, 2025 of $159.1 million was $4.3 million (or 3%) lower than the same period in 2024, as lower production services revenue was offset by higher contract drilling revenue in Canada.
- Despite revenue decreasing for the nine months ended September 30, 2025, Adjusted EBITDA of $33.0 million was $1.1 million (or 3%) higher compared to $31.9 million in the same period of 2024, due to cost synergy savings associated with a reorganization of senior management in 2025. Included in Adjusted EBITDA for the nine months ended September 30, 2025, was $3.6 million of one-time reorganization costs, compared to $2.8 million in 2024. After normalizing for one-time reorganization costs in both periods, Adjusted EBITDA for the nine months ended September 30, 2025 would have totalled $36.6 million, compared to $34.7 million in 2024, an increase of $1.9 million due to higher drilling revenue in Canada and lower administrative expenses, which were offset partially by lower production services activity in Canada and lower drilling activity in the US.
- The Company incurred a net loss of $4.4 million for the nine months ended September 30, 2025 ($0.13 net loss per basic common share) as compared to a net loss of $4.9 million in the same period of 2024 ($0.14 net loss per basic common share) as higher Adjusted EBITDA, and decreases in stock based compensation expense and finance costs were offset by a $2.0 million higher loss on the sale of fixed assets and a lower income tax recovery.
- For the nine months ended September 30, 2025, additions to property and equipment of $16.4 million compared to $15.8 million in the same period of the prior year, consisting of $4.1 million of expansion capital related to rig upgrades and $12.3 million of maintenance capital.
- On January 27, 2025, the Company announced that it extended the maturity date of its Second Lien Facility (as defined in this MD&A) from May 18, 2026 to May 18, 2027. The Company also made a voluntary principal repayment of $5.0 million on its Second Lien Facility in the second quarter of 2025.

Operational Highlights:

- In Canada, Operating Days of 3,099 for the nine months ended September 30, 2025, were 375 days (or 14%) higher compared to 2,724 days in the same period of the prior year. Drilling rig utilization in Canada was 33% for the nine months ended September 30, 2025, compared to 29% in the same period of the prior year, mainly due to more upgraded rigs working through spring break up in 2025 than in 2024, as well as improved customer retention year over year due to targeted marketing efforts.
- Revenue per Operating Day in Canada averaged $32,344 for the nine months ended September 30, 2025, which was consistent with the same period of the prior year.

- In the US, drilling rig utilization averaged 22% for the nine months ended September 30, 2025, which was lower than 28% in the same period in the prior year, due to continued low industry activity in the US and a change in focus to North Dakota from Texas.
- Revenue per Operating Day in the US for the nine months ended September 30, 2025 averaged US$31,108, a 4% increase compared to US$29,904 in the same period of the prior year, mainly due to changes in rig mix.
- In Canada, service rig utilization was 26% in the nine months ended September 30, 2025 compared to 36% in the same period of the prior year, as Service Hours decreased by 28% to 31,946 hours from 44,368 hours in the same period of the prior year, mainly due to changes in customer programs.
- Revenue per Service Hour averaged $1,021 for the nine months ended September 30, 2025, and was consistent with the same period in the prior year.

Outlook

In 2025, commodity prices faced downward pressure due to trade tensions resulting from US tariffs on imports and retaliatory measures from several countries. These actions contributed to a broader global trade conflict, heightening uncertainty in the global economy. Ongoing geopolitical conflict in Eastern Europe and the Middle East, combined with persistently weak global demand for crude oil, further impacted market sentiment. These macroeconomic factors are expected to impact commodity prices through the remainder of 2025. Additionally, in Canada, changes in government priorities arising from the change in leadership of the federal government that occurred in 2025 may lead to continuing shifts in energy policy, potentially affecting the approval of future energy infrastructure projects. This contributes to additional uncertainty for the Canadian energy services industry. The precise duration and extent of the adverse impacts of the current macroeconomic environment on Western's customers and operations remains uncertain at this time.

Despite these headwinds, recent infrastructure developments present opportunities for the energy services industry. The Trans Mountain pipeline expansion commenced operations on May 1, 2024, providing critical takeaway capacity. Additionally, the Coastal GasLink pipeline delivered its first shipment of liquefied natural gas on June 30, 2025, and the LNG Canada project has begun operations in British Columbia. These projects are expected to support increased activity in Western Canada's energy sector. Western is also cautiously optimistic that the current trade environment may prompt renewed focus among Canadian provinces on strengthening domestic energy independence, which may help accelerate additional project approvals.

To navigate this complex environment, Western has implemented several strategic initiatives in 2025, including a reorganization of senior leadership to enhance operational efficiency and support long-term growth. As part of this process, the decision was made to focus on US operations exclusively in North Dakota and redeploy assets previously operating in Texas. The Company remains focused on managing fixed costs, preserving balance sheet strength, deleveraging the business, and maintaining flexibility to respond to market conditions. With these initiatives in place, Western believes it is well-positioned to benefit from improving service demand and pricing momentum. Western's upgraded rig fleet positions the Company to remain competitive in a tightening market. The total rig fleet in the WCSB has decreased from 385 drilling rigs at September 30, 2024 to 373 drilling rigs as of October 21, 2025, representing a decrease of 12 drilling rigs, or 3%, which reduces the supply of drilling rigs for such projects. Currently, 19 of Western's drilling rigs and 13 of Western's well servicing rigs are operating.

As disclosed previously, Western's board of directors approved a capital budget for 2025 of $20 million. The 2025 budget included approximately $3 million of committed expenditures from 2024 to be carried forward into 2025. Western will continue to manage its costs in a disciplined manner and make required adjustments to its capital program as customer demand changes.

In the near term, the primary challenges facing the energy services industry include commodity price volatility, the impact of industry consolidation on Western's exploration and production customers and potential customers, and constrained customer drilling activity, as exploration and production companies continue to prioritize shareholder returns through share repurchases, increased dividends, and debt reduction rather than production growth. Should commodity prices stabilize over a sustained period, and as customers further strengthen their balance sheets, an increase in drilling activity may follow. Over the medium term, Western believes its rig fleet is well positioned to benefit from increased drilling and production activity associated with the completion of the LNG Canada project and the Trans Mountain pipeline expansion. In addition, increased focus on domestic energy security and economic independence may support further development activity across the sector.

Review of Results for the Quarter and Nine Months Ended September 30, 2025 – Segmented Information

Contract Drilling

Financial Highlights	Three months ended September 30			Nine months ended September 30		
(stated in thousands)	2025	2024	Change	2025	2024	Change
Revenue	37,840	43,590	(13%)	118,627	110,377	7%
Expenses						
Operating	25,428	32,369	(21%)	85,070	80,970	5%
Administrative	1,611	2,334	(31%)	5,633	6,533	(14%)
Adjusted EBITDA(1)	10,801	8,887	22%	27,924	22,874	22%
Adjusted EBITDA as a percentage of revenue(1)	29%	20%	45%	24%	21%	14%
Operating Highlights(2)						
Canadian Operations						
Operating Days	1,022	1,115	(8%)	3,099	2,724	14%
Revenue per Operating Day(1)	30,425	31,141	(2%)	32,344	32,373	-
Drilling rig utilization	33%	36%	(8%)	33%	29%	14%
CAOEC industry Operating Days(3)	15,097	17,398	(13%)	43,744	45,761	(4%)
United States Operations						
Operating Days	146	229	(36%)	423	546	(23%)
Revenue per Operating Day (US$)(1)	33,669	28,429	18%	31,108	29,904	4%
Drilling rig utilization	24%	36%	(33%)	22%	28%	(21%)

(1) See "Non-IFRS Measures and Ratios" on page 14 of this MD&A.

(2) See "Defined Terms" on page 15 of this MD&A.

(3) Source: The CAOEC monthly Contractor Summary, calculated on a spud to rig release basis.

- For the third quarter of 2025, contract drilling revenue totalled $37.8 million, a $5.8 million (or 13%) decrease as compared to the same period in the prior year due to lower operating days in both Canada and the US. For the nine months ended September 30, 2025, contract drilling revenue totalled $118.6 million, an $8.2 million (or 7%) increase as compared to the same period in the prior year. The change for the nine months ended September 30, 2025 was due to more upgraded rigs working in Canada through spring break up, coupled with improved marketing efforts, partially offset by lower activity in the US. See “*Canadian Operations*” and “*United States Operations*” below.
- Administrative expenses for the three months ended September 30, 2025 totalled $1.6 million, a $0.7 million (or 31%) decrease compared to the same period of the prior year due to lower employee related costs. For the nine months ended September 30, 2025, administrative expenses totalled $5.6 million and were $0.9 million (or 14%) lower than the same period in the prior year due to lower employee related costs.
- Contract drilling Adjusted EBITDA of $10.8 million in the third quarter of 2025 was $1.9 million, or 22%, higher than $8.9 million in the third quarter of 2024, mainly due to operational efficiencies from the reorganization of senior leadership, which was offset partially by lower activity in both Canada and the US, and changes in rig mix in both the US and Canada.
- For the nine months ended September 30, 2025, contract drilling Adjusted EBITDA of $27.9 million was $5.0 million, or 22%, higher than the same period of the prior year due to higher contract drilling activity in Canada which was offset partially by lower activity in the US. Adjusted EBITDA for the nine months ended September 30, 2025 included $2.1 million of one-time reorganization costs. Normalizing for these one-time reorganization costs, contract drilling Adjusted EBITDA would have totalled $30.0 million for the nine months ended September 30, 2025, a 31% increase compared to the same period of the prior year.
- During the third quarter of 2025, the Company disposed of a drilling rig from its US operations for a loss of $3.3 million.

Canadian Operations

- Operating Days for the third quarter of 2025 of 1,022 days were 8% lower than 1,115 days in the same period of the prior year, compared to a 13% decrease in CAOEC industry Operating Days, resulting in drilling rig utilization in Canada of 33% in 2025, compared to 36% in 2024. The decrease in Operating Days for the third quarter of 2025 was mainly attributed to continued low oil prices, impacting customer programs.

- Operating days for the nine months ended September 30, 2025 of 3,099 days were 14% higher than 2,724 days in the same period of the prior year, compared to a 4% decrease in CAOEC industry Operating Days, resulting in drilling rig utilization in Canada of 33% in 2025, compared to 29% in 2024. The increase in Operating Days for the nine months ended September 30, 2025 was mainly due to improved customer retention year over year from marketing efforts, as well as the Company's upgraded rigs working more through spring break up compared to 2024.
- For the three and nine months ended September 30, 2025, revenue per Operating Day averaged $30,425 and $32,344 respectively, compared to $31,141 and $32,373 in the same periods of the prior year due to changes in rig mix.

United States Operations

- For the three months ended September 30, 2025, Operating Days in the US decreased by 36% to 146 days compared to 229 days in the same period of the prior year, which resulted in drilling rig utilization of 24% in the third quarter of 2025, which was lower than the third quarter of 2024 of 36%. Average active industry rigs of 540[5] in the third quarter of 2025 were 8% lower compared to the third quarter of 2024 due to low natural gas prices.
- For the nine months ended September 30, 2025, Operating Days in the US decreased by 23% to 423 days compared to 546 days in the same period of the prior year, which resulted in drilling rig utilization of 22% in 2025, which was lower than 28% in 2024. Average industry rigs of 566[5] for the nine months ended September 30, 2025 were 6% lower, compared to the same period in the prior year.
- For the three months ended September 30, 2025, revenue per Operating Day increased by 18% averaging US$33,669 compared to US$28,429. Similarly, for the nine months ended September 30, 2025, revenue per Operating Day increased by 4% averaging US$31,108 compared to US$29,904. The changes for both periods were due to changes in rig mix as the Company shifted its focus to North Dakota from Texas.

Production Services

Financial Highlights	Three months ended September 30			Nine months ended September 30		
(stated in thousands)	2025	2024	Change	2025	2024	Change
Revenue	12,206	14,813	(18%)	40,622	53,246	(24%)
Expenses						
Operating	8,263	10,108	(18%)	29,198	35,418	(18%)
Administrative	1,280	1,270	1%	3,970	3,834	4%
Adjusted EBITDA(1)	2,663	3,435	(22%)	7,454	13,994	(47%)
Adjusted EBITDA as a percentage of revenue(1)	22%	23%	(4%)	18%	26%	(31%)
Operating Highlights(2)						
Service Hours	9,838	12,525	(21%)	31,946	44,368	(28%)
Revenue per Service Hour(1)	950	979	(3%)	1,021	1,023	-
Service rig utilization	24%	31%	(23%)	26%	36%	(28%)

(1) See "Non-IFRS Measures and Ratios" on page 14 of this MD&A.

(2) See "Defined Terms" on page 15 of this MD&A.

- For the quarter ended September 30, 2025, production services revenue decreased by $2.6 million, or 18%, to $12.2 million, compared to the same period of the prior year. Similarly, for the nine months ended September 30, 2025, production services revenue decreased by $12.6 million, or 24%, to $40.6 million, compared to the same period of the prior year. For both the three and nine months ended September 30, 2025, the decrease was due to fewer Service Hours resulting from changes in customer programs.
- For the three months ended September 30, 2025, Service Hours of 9,838 (24% utilization) were 21% lower than the same period of the prior year of 12,525 (31% utilization). For the nine months ended September 30, 2025 Service Hours of 31,946 (26% utilization) were 28% lower than the same period of the prior year of 44,368 (36% utilization). The decrease in Service Hours for both the three and nine months ended September 30, 2025 was due to changes in customer programs.

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

- For the three months ended September 30, 2025, revenue per Service Hour averaged $950 and was 3% lower than the same period of 2024, due to area-specific rig requirements. For the nine months ended September 30, 2025, revenue per Service Hour averaged $1,021 and was consistent with the same period of the prior year.
- For the three months ended September 30, 2025, administrative expenses of $1.3 million was consistent with the same period of the prior year. For nine months ended September 30, 2025, administrative expenses were $0.2 million (or 4%) higher than the nine months ended September 30, 2024, due to one-time reorganization costs of $0.7 million incurred, which were partially offset by lower employee related expenses.
- Adjusted EBITDA decreased for the three months ended September 30, 2025, by $0.7 million (or 22%) to $2.7 million, compared to $3.4 million in the same period of the prior year mainly due to customers program changes resulting from low commodity prices. For the nine months ended September 30, 2025, Adjusted EBITDA decreased by $6.5 million, or 47%, to $7.5 million, compared to $14.0 million in the same period of the prior year, mainly due to customer program changes and one-time reorganization costs of $0.7 million.

Corporate

	Three months ended September 30			Nine months ended September 30		
(stated in thousands)	**2025**	**2024**	**Change**	**2025**	**2024**	**Change**
Expenses						
Administrative	402	889	(55%)	2,387	4,957	(52%)

- For the three months ended September 30, 2025, corporate administrative expenses totalled $0.4 million and were $0.5 million (or 55%) lower than the same period of the prior year mainly due to lower employee related costs.
- For the nine months ended September 30, 2025, corporate administrative expenses totalled $2.4 million and were $2.6 million (or 52%) lower than the same period of the prior year due to lower employee related costs and $2.1 million of one-time reorganization costs in 2024, which were offset partially by $0.8 million of one-time reorganization costs incurred in 2025.

Consolidated Other Expenses

	Three months ended September 30			Nine months ended September 30		
(stated in thousands)	**2025**	**2024**	**Change**	**2025**	**2024**	**Change**
Depreciation	10,524	10,067	5%	30,915	30,665	1%
Stock based compensation	238	157	52%	(931)	433	(315%)
Finance costs	2,162	2,476	(13%)	6,801	7,626	(11%)
Other items	3,050	316	865%	1,883	(456)	(513%)
Income tax recovery	(670)	(393)	70%	(1,236)	(1,486)	(17%)

- Depreciation expense for the three months ended September 30, 2025, totalled $10.5 million compared to $10.1 million in the same period of the prior year. Depreciation expense for the nine months ended September 30, 2025, totalled $30.9 million compared to $30.7 million in the same period of the prior year.
- Stock based compensation for the three months ended September 30, 2025, totalled an expense of $0.2 million, which was consistent with the same period of the prior year. For the nine months ended September 30, 2025, stock based compensation totalled a recovery of $0.9 million, compared to an expense of $0.4 million in the same period of the prior year, due to forfeiture recoveries related to one-time reorganization changes in the period.
- Finance costs in the third quarter of 2025 of $2.2 million were $0.3 million lower than the same period of the prior year and represented an effective interest rate of 8.7%, compared to 8.6% in the third quarter of 2024. Similarly, finance costs for the nine months ended September 30, 2025 of $6.8 million were $0.8 million lower than the same period of the prior year and represented an effective interest rate of 8.6%, compared to 8.7% in 2024. The decrease for both the three and nine months ended September 30, 2025 was mainly due to lower total debt levels resulting from Western's debt repayments made in 2024 and 2025.
- For the three and nine months ended September 30, 2025, other items relate to foreign exchange gains and losses and the sale of assets. During the third quarter of 2025, the Company disposed of a drilling rig from its US operations for a loss of $3.3 million.
- For the third quarter of 2025, the consolidated income tax recovery totalled $0.7 million, compared to a recovery of $0.4 million in the same period of the prior year, representing an effective tax rate of 23.0%, as compared to an effective tax

rate of 24.8% in the same period of 2024. For the nine months ended September 30, 2025, the consolidated income tax recovery totalled $1.2 million and represented an effective tax rate of 21.8%, compared to 23.4% in the same period of 2024. The Company had no cash taxes payable for the three or nine months ended September 30, 2025.

Liquidity and Capital Resources

The Company's liquidity requirements in the short and long term can be sourced in several ways including: available cash and cash equivalents, cash flow from operating activities, borrowing against the Credit Facilities, new debt instruments, equity issuances and proceeds from the sale of assets. As at September 30, 2025, Western had working capital of $19.4 million compared to working capital of $9.9 million as at December 31, 2024.

During the nine months ended September 30, 2025, Western had the following changes to its cash balances in the period, which resulted in a $0.3 million decrease in cash and cash equivalents in the period:

Cash and cash equivalents (stated in thousands)	
Opening balance, at December 31, 2024	3,785
Add:	
Adjusted EBITDA[1]	32,991
Proceeds on sale of property and equipment	2,815
Draw on Credit Facilities	1,076
Deduct:	
Additions to property and equipment	(16,398)
Finance costs paid	(8,663)
Principal repayment of Second Lien debt	(5,810)
Change in non cash working capital	(3,437)
Principal repayment of lease obligations	(1,086)
Principal repayment of HSBC Facility	(938)
Principal repayment of US paycheck protection plan	(810)
Other items	(68)
Ending balance, at September 30, 2025	**3,457**

(1) See "Non-IFRS Measures and Ratios" on page 14 of this MD&A.

As at September 30, 2025, Western had a total of $5.5 million drawn on 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") and $3.8 million outstanding on its committed term non-revolving facility (the "HSBC Facility"), which matures on December 31, 2026. As at September 30, 2025, Western had $82.4 million outstanding on its second lien secured term loan with Alberta Investment Management Corporation (the "Second Lien Facility"), which matures on May 18, 2027 after the extension announced on January 27, 2025. During the second quarter of 2025, the Company made a voluntary prepayment of $5.0 million on its Second Lien Facility. On August 7, 2025, the Company's US paycheck protection plan loan ("PPP Loan") matured and the Company made its final principal payment on the loan. As such, there was no balance outstanding at September 30, 2025, related to the PPP Loan.

As part of the Second Lien Facility extension, the maturity date of the Company's Credit Facilities was automatically extended from November 18, 2025 to the earlier of (i) six months prior to the maturity date of the amended Second Lien Facility of November 18, 2026 or (ii) March 22, 2027. Cash flow from operating activities and available Credit Facilities are expected to be sufficient to cover Western's financial obligations, including working capital requirements and 2025 budgeted 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 included in 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 Stoneham Drilling Corporation ("Stoneham"). A summary of the Company's financial covenants at September 30, 2025 is as follows:

September 30, 2025	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 September 30, 2025 condensed consolidated financial statements.

At September 30, 2025, 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 break up" 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 (stated in thousands, except per share amounts)	Sep 30, 2025	Jun 30, 2025	Mar 31, 2025	Dec 31, 2024	Sep 30, 2024	Jun 30, 2024	Mar 31, 2024	Dec 31, 2023
Revenue	50,035	40,005	69,010	59,720	58,343	43,033	61,982	56,255
Adjusted EBITDA[1]	13,062	5,853	14,076	10,316	11,433	5,259	15,219	13,370
Cash flow from operating activities	8,452	19,804	2,678	14,332	5,404	19,260	7,802	6,268
Net income (loss)	(2,242)	(4,585)	2,386	(1,995)	(1,190)	(5,136)	1,455	(2,194)
per share - basic and diluted	(0.07)	(0.14)	0.07	(0.06)	(0.04)	(0.15)	0.04	(0.06)
Total assets	405,949	407,791	438,232	430,981	429,623	433,354	441,781	442,933
Long-term debt - non current portion	90,445	89,057	102,193	91,657	102,999	106,912	111,109	111,174

(1) See "Non-IFRS Measures and Ratios" on page 14 of this MD&A.

Revenue and Adjusted EBITDA were impacted by commodity prices and market uncertainty throughout the last eight quarters. In 2023, 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 Eastern Europe and in the Middle East impacted the energy services industry. In 2024, volatile commodity prices persisted, with low commodity prices in the first and third quarters, particularly natural gas prices, which resulted in instability with customer programs and lower industry activity. The first three quarters of 2025 were impacted by import tariffs announced by the US government, and the ongoing conflicts in Eastern Europe and the Middle East, resulting in market volatility. The Company is cautiously optimistic that due to the recent sentiment in Canada towards expanding to other markets, and reducing the Canadian dependency on US markets, Canadian energy will play an important role in the future of Canada's economy.

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 September 30, 2025 are as follows:

(stated in thousands)	2025	2026	2027	2028	2029	Thereafter	Total
Trade payables and other current liabilities (1)	17,082	-	-	-	-	-	17,082
Operating commitments (2)	2,202	852	772	770	769	372	5,737
Second Lien Facility principal	270	1,080	81,102	-	-	-	82,452
Second Lien Facility interest	-	6,974	6,057	-	-	-	13,031
HSBC Facility principal	-	3,750	-	-	-	-	3,750
HSBC Facility interest	64	199	-	-	-	-	263
Lease obligations (3)	639	2,012	1,547	1,235	720	450	6,603
Operating Facility	-	5,499	-	-	-	-	5,499
Total	**20,257**	**20,366**	**89,478**	**2,005**	**1,489**	**822**	**134,417**

(1) Trade payables and other current liabilities exclude interest accrued as at September 30, 2025 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, 2027.

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.

Operating Facility:

The Company's Operating Facility matures on the earlier of (i) six months prior to the maturity date of the Second Lien Facility, which is currently November 18, 2026 after the change to the maturity date noted previously, or (ii) March 22, 2027 if the Second Lien Facility is extended.

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

Outstanding Share Data

	October 21, 2025	September 30, 2025	December 31, 2024
Common shares outstanding	33,843,022	33,843,022	33,843,022
Stock options outstanding	1,108,921	1,108,921	2,666,189

Off Balance Sheet Arrangements

As at September 30, 2025, 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 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 September 30, 2025, 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 (loss).

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.

The Company's practice is to manage credit risk by performing a thorough analysis of the creditworthiness of new customers by reviewing their financial position before credit terms are offered. In some cases, the Company may request prepayment before services are provided to help minimize credit risk. 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.

The following table provides an analysis of the Company's trade and other receivables as at September 30, 2025 and December 31, 2024:

Balances at (stated in thousands)	**September 30, 2025**	**December 31, 2024**
Trade receivables	29,741	30,473
Accrued trade receivables	7,688	8,392
Other receivables	165	678
Allowance for doubtful accounts	(1,887)	(1,985)
Total	**35,707**	**37,558**

For the three months ended September 30, 2025, the Company had one customer comprising 11.5% of the Company's total revenue. This customer was also a significant customer for the nine months ended September 30, 2025, comprising 10.1% of the Company's total revenue. There was a second significant customer for the nine months ended September 30, 2025 comprising 12.1% of the Company's total revenue. The total trade receivable balance outstanding related to the two significant customers for 2025 represented 10.0% and 5.4% respectively, of the Company's total trade and other receivables as at September 30, 2025. For the three and nine months ended September 30, 2024, the Company had no customers comprising 10.0% or more of the Company's total revenue. There were no significant customers for the year ending December 31, 2024.

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 flow 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 Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") of the Company have certified as at September 30, 2025 that they have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") to provide reasonable assurance that: (i) material information relating to the Company, including its consolidated subsidiaries, is made known to the CEO and the CFO by others within those entities, particularly during the periods in which the interim filings of the Company are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

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

During the three and nine months ended September 30, 2025, 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 3 of the Company's consolidated financial statements as at December 31, 2024 and for the years ended December 31, 2024 and 2023. There were no new accounting standards or amendments to existing standards adopted in the three and nine months ended September 30, 2025, 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 nine months ended September 30, 2025, 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, 2024. 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, 2024 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 ("Non-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-IFRS 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 (loss) 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 September 30		Nine months ended September 30	
(stated in thousands)	**2025**	**2024**	**2025**	**2024**
Net loss	**(2,242)**	**(1,190)**	**(4,441)**	**(4,871)**
Income tax recovery	(670)	(393)	(1,236)	(1,486)
Loss before income taxes	**(2,912)**	**(1,583)**	**(5,677)**	**(6,357)**
Add (deduct):				
Depreciation	10,524	10,067	30,915	30,665
Stock based compensation	238	157	(931)	433
Finance costs	2,162	2,476	6,801	7,626
Other items	3,050	316	1,883	(456)
Adjusted EBITDA	**13,062**	**11,433**	**32,991**	**31,911**

The following table reconciles Adjusted EBITDA, defined previously, to operating earnings (loss) as disclosed in the condensed consolidated financial statements for the three and nine months ended September 30, 2025 and 2024:

	Three months ended September 30, 2025			
(stated in thousands)	**Contract Drilling**	**Production Services**	**Corporate**	**Total**
Adjusted EBITDA	10,801	2,663	(402)	13,062
Depreciation	(8,305)	(1,906)	(313)	(10,524)
Operating earnings (loss)	**2,496**	**757**	**(715)**	**2,538**

	Three months ended September 30, 2024			
(stated in thousands)	**Contract Drilling**	**Production Services**	**Corporate**	**Total**
Adjusted EBITDA	8,887	3,435	(889)	11,433
Depreciation	(7,669)	(2,033)	(365)	(10,067)
Operating earnings (loss)	**1,218**	**1,402**	**(1,254)**	**1,366**

				Nine months ended September 30, 2025
(stated in thousands)	Contract Drilling	Production Services	Corporate	Total
Adjusted EBITDA	27,924	7,454	(2,387)	32,991
Depreciation	(24,044)	(5,789)	(1,082)	(30,915)
Operating earnings (loss)	**3,880**	**1,665**	**(3,469)**	**2,076**

				Nine months ended September 30, 2024
(stated in thousands)	Contract Drilling	Production Services	Corporate	Total
Adjusted EBITDA	22,874	13,994	(4,957)	31,911
Depreciation	(23,211)	(6,303)	(1,151)	(30,665)
Operating earnings (loss)	**(337)**	**7,691**	**(6,108)**	**1,246**

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.

Defined Terms

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.

Working capital: Calculated as current assets less current liabilities as disclosed in the Company's consolidated financial statements.

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"); 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 impact of Western's upgraded drilling rigs; the potential continued impact of the current conflicts in Eastern Europe and the Middle East and other macroeconomic factors on commodity prices; the Company's capital budget for 2025, including the allocation of such budget; Western's plans for managing its capital program; the energy service industry and global economic activity; the expected impact of industry consolidation on Western's customers and potential customers; expectations of increased industry activity with respect to the Trans Mountain pipeline project, the Coastal GasLink pipeline project and the LNG Canada project; the impact of the US tariffs on the approach of Canadian governments towards approval of Canadian energy projects and a focus on domestic energy independence; the effect of continued changes in Canadian government policies arising from recent changes in government leadership; the Company's ability to benefit from improving service demand and pricing momentum; the Company's ability to continue to focus on deleveraging the business; the Company's ability to adjust its capital program and manage costs; challenges facing the energy service industry; expectations regarding future drilling and well servicing activity; expectations surrounding the level of investment in Canada and its impact on the Company; 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; expectations relating to activity levels for oilfield services; 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 Company's 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 business segments to access equipment; global economic conditions and the accuracy of the Company's market outlook expectations for 2025 and in the future; the impact, direct and indirect, of epidemics, pandemics, other public health crisis and geopolitical events, including the conflicts in Eastern Europe and the Middle East and the import tariffs implemented by the US administration, on Western's business, customers, business partners, employees, supply chain, other stakeholders and the overall economy; changes in laws, regulations, or policies; 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, inflation 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, 2024, 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.