

ULTRA-MEOR®

2026 North African Field Pilot Analysis & Case Study

FIELD RESULT A mature conventional sandstone well produced a 67.9% higher 90-day average oil rate, a 59.2% lower average produced-water rate, and approximately 12,018 incremental barrels of oil during the monitored period. The treatment used existing wellhead and production infrastructure.

1. Pilot background

The 2026 pilot was conducted on a mature conventional oil well operated by a North African National Oil Company. The public-facing case study withholds the operator, field name and well identifier. The well was drilled in November 1964 to 2,767 ft and targets an Oligocene sandstone interval with approximately 30% porosity and 600 md permeability. Crude gravity is 32.1° API, bottom-hole temperature is approximately 121°F, and the well produces with an ESP.

Parameter	Reported value	Parameter	Reported value
Original drill date	November 1964	Total depth	2,767 ft
Target reservoir	Oligocene sandstone	Porosity	~30%
Permeability	~600 md	Oil gravity	32.1° API
BHT	~121°F	Artificial lift	ESP

2. Treatment execution

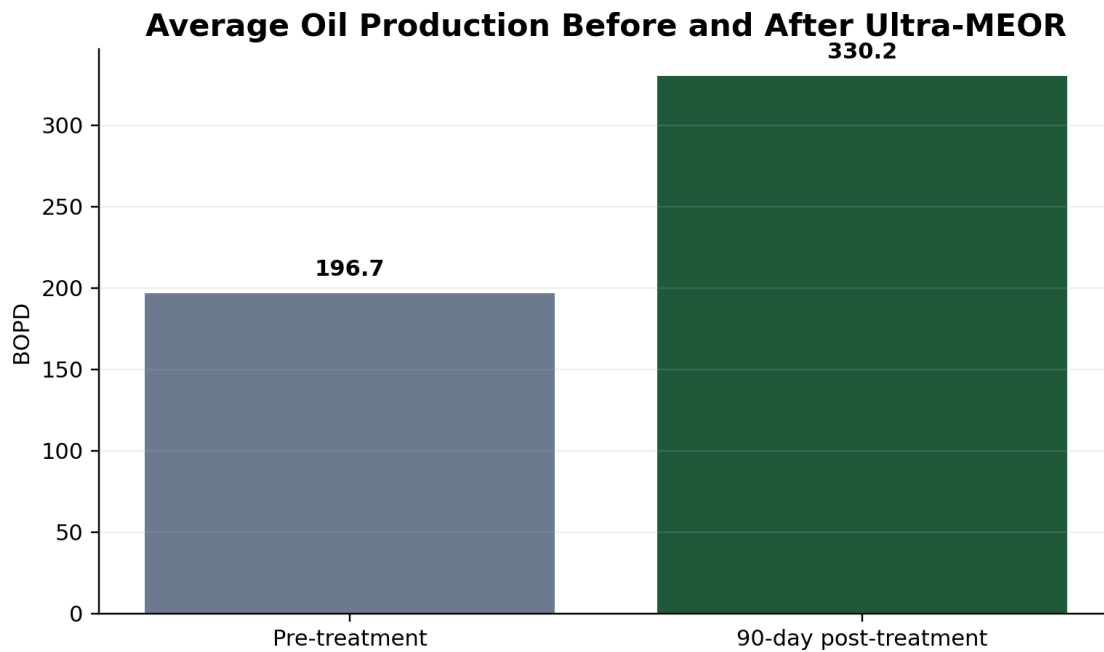
Ultra-MEOR was prepared and injected through existing surface and wellhead equipment, displaced into the target interval, and followed by an approximately four-day shut-in. The well then returned to production using the existing ESP. No modification to the producing completion or surface production facilities was required.

3. Data basis

The analysis uses three accepted pre-treatment tests dated November 16, November 26 and February 6, and ten post-treatment tests from April 6 through June 25. Average production is the arithmetic mean of accepted tests. Aggregate water cut is calculated from average water divided by average oil plus water. The 90-day incremental-oil calculation uses the unrounded difference between the accepted oil-rate averages.

4. Production performance

Metric	Pre-treatment average	90-day post-treatment average	Observed change
Oil production	196.7 BOPD	330.2 BOPD	+133.5 BOPD / +67.9%
Produced water	134.7 BWPD	54.9 BWPD	-79.8 BWPD / -59.2%
Total fluid	331.4 BFPD	385.1 BFPD	+53.7 BFPD / +16.2%
Water cut	40.6%	14.3%	-26.4 percentage points
Oil-to-water ratio	1.46:1	6.01:1	~4.1× improvement



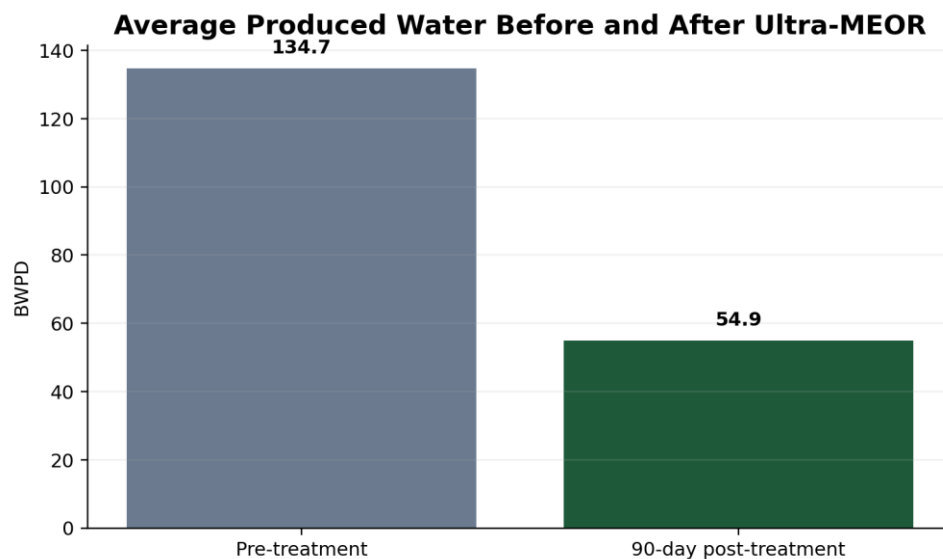
Average oil production increased from 196.7 to 330.2 BOPD during the monitored period.

5. Oil-response shape

The first post-treatment test was 304 BOPD, already about 54% above the accepted baseline average. Oil later peaked at 444 BOPD on May 4. Production remained above the baseline average through most of the monitored period before declining toward the pre-treatment range in June. The final test was 268 BOPD. This response shape is commercially important: the full curve, not the peak, should drive economics and retreatment decisions.

6. Produced-water response

Average produced water declined from 134.7 to 54.9 BWPD. Aggregate water cut declined from 40.6% to 14.3%. The final June 25 test reported 36 BWPD and 12% water cut compared with 187 BWPD and 42% water cut in the final pre-treatment test. The result indicates a persistent water-performance signal even as oil production declined from its peak.

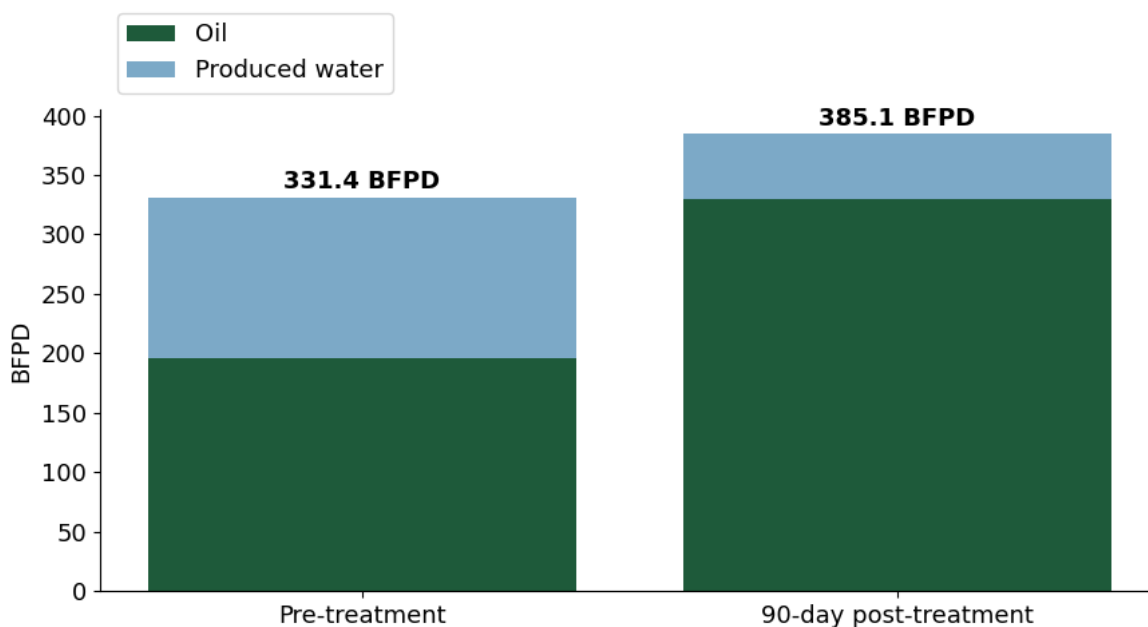


Average produced water decreased by 59.2% during the 90-day monitoring period.

7. Why the combined oil and water response matters

Average total fluid increased only 16.2%, from 331.4 to 385.1 BFPD, while the produced-fluid composition changed sharply toward oil. This distinguishes the result from a simple proportional increase in total liquid deliverability. The field data do not establish the mechanism. Plausible contributors include interfacial and biosurfactant effects, oil-rock detachment, wettability or relative-flow changes, paraffin or wax modification, selective modification of preferential flow paths, or a combination of these effects.

Produced-Fluid Composition Before and After Ultra-MEOR



The production mix shifted substantially toward oil while total fluid increased moderately.

8. Illustrative 90-day economics

Measure	Illustrative result
Incremental oil	~12,018 barrels
Gross incremental oil revenue at \$75/bbl	~\$901,350
Illustrative total intervention cost	\$50,000
Gross value above intervention cost	~\$851,350
Revenue-to-cost multiple	~18×
Intervention cost per incremental barrel	~\$4.16/bbl
Illustrative payout	~5 days gross / ~10 days at 50% netback

9. Technical interpretation and limitations

The pilot is best characterized as a successful modern single-well proof of concept. It demonstrated deployability through existing infrastructure and a substantial 90-day oil and water response. It did not include an untreated control well, interfacial-tension testing, wettability measurements, production logging, tracers, microbial tracking, detailed metabolite analysis or deposit characterization. The baseline was also variable. These limitations do not erase the measured response, but they define what the next pilots should improve.

10. Recommended next steps

Replicate the treatment in one or more comparable mature sandstone candidates to test repeatability, while also selecting carefully characterized wells with different geology, permeability, oil gravity and water behavior to define operating range. Future trials should lock baseline and operating conditions, document completion and treated intervals, add targeted diagnostics, and monitor through material decline or retreatment. All results should enter the Ultra-MEOR cross-well learning database.

CASE-STUDY CONCLUSION The 2026 North African pilot provides the strongest modern evidence currently available for Ultra-MEOR. Average oil increased 67.9%, average produced water decreased 59.2%, and the produced-fluid composition shifted materially toward oil. The result supports controlled replication and mechanism-focused follow-up rather than a universal performance claim.

Source basis: Ultra-MEOR Global White Paper V10, August 22, 2026, and the North African field records summarized therein.