BENDING THE CURVE: THE INNOVATIVE REVIVAL OF ACIDIZING IN HORIZONTAL WELLS

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INTRODUCTION

With an estimated 46,000 horizontal wells in the Permian Basin currently yielding less than 200 BOPD, operators are facing a growing inventory of declining wells. This base production decline must be continually offset by new well additions—an increasingly costly and resource-intensive strategy. As a result, the industry is experiencing a resurgence of acidizing treatments in horizontal wells as a means to restore productivity and extend asset life.

This paper presents the latest strategies and innovations driving the effective revitalization of horizontal wells through acid stimulation. Emphasis is placed on well candidate selection, diversion methods, integrating modern chemical systems, operational best practices, and field-proven designs to maximize production gains while maintaining long-term well integrity.

WELL CANDIDATE SELECTION

Successful acid stimulation treatments begin with proper candidate selection. A comprehensive evaluation of several key variables is essential, including scaling tendencies, production history, hydrogen sulfide (H_2S) levels, bottomhole pressure, temperature changes, and the presence of organic deposits. Careful analysis of these factors helps determine whether an acid treatment is technically justified and likely to restore well performance.

Water analysis plays a central role in identifying downhole scaling tendencies in Permian Basin wells. This evaluation typically quantifies H_2S concentration, acid-soluble scale components such as calcium carbonate, iron, and iron sulfide (FeS), as well as acid-insoluble scales including calcium sulfate, strontium sulfate, barium sulfate, and iron sulfide forms such as pyrite and marcasite (FeS_2). Identifying the dominant scaling mechanisms is critical, as it determines whether the well is an appropriate acid candidate and the specific treatment chemistry required.

However, water chemistry alone should not dictate treatment decisions. Production trends, bottomhole pressure decline, and evidence of organic deposition must also be evaluated to accurately diagnose the cause of performance loss. In many cases, these operational indicators provide clearer evidence of near-wellbore damage than water analysis by itself.

Well age is another important consideration. A study of 380 acid stimulation treatments showed that wells between 2 and 5 years old achieved a 58% greater production increase at 60 days post-treatment compared to wells only 0–1 year old. [1] Wells within the 2–5 year production window are more likely to have accumulated scale, carbonate formation fill, and other flow-restricting deposits that impair productivity. These types of damage are often effectively removed through properly designed acid stimulation.

Conversely, intervening too early in a well's lifecycle may be premature. During the initial stages of production, scale deposition and formation fill are typically minimal. Production declines in newer wells are more commonly associated with reservoir depletion, offset well interference, artificial lift inefficiencies, or mechanical issues such as sand bridges rather than mineral scaling.

In the Permian Basin, the two primary scale types encountered are calcium carbonate and iron sulfide. Calcium carbonate scale typically forms when calcium-rich formation water experiences pressure and temperature reductions during production. Iron sulfide scale forms when dissolved iron (ferrous Fe^{2+} or ferric Fe^{3+}), often generated through corrosion, reacts with hydrogen sulfide (H_2S), producing low-solubility iron sulfide deposits. Both mechanisms are prevalent in Permian wells due to carbonate reservoirs, high water production, CO_2 presence, and sour operating conditions.

Organic deposition, including paraffin and asphaltenes, must also be considered during candidate evaluation. Acid systems are aqueous and therefore ineffective at dissolving non-polar hydrocarbon deposits. When organics coat scaling or formation surfaces, they can inhibit acid contact and reduce treatment effectiveness. In such cases, solvent-based treatments or surfactant pre-flushes are required ahead of the acid stage to dissolve or disperse organic deposits to allow proper acid penetration.

A comprehensive candidate evaluation that integrates water chemistry, production diagnostics, well maturity, and organic damage assessment significantly increases the likelihood of a technically successful and economically justified acid stimulation treatment.

TREATMENT CHEMISTRY FORMULATION

Once a well has been identified as a candidate for acid stimulation, it is critical to design the most effective acid formulation to achieve optimal results. The most reliable approach to selecting the appropriate chemical additives is to obtain and analyze well samples of crude oil and formation water. Laboratory testing of these fluids provides valuable insight into fluid compatibility, emulsion tendencies, and overall treatment design.

One key—but often overlooked—factor that can significantly reduce the effectiveness of an acid treatment is the wettability state of the formation. Evaluating a sample of crude oil and formation water can help indicate formation wettability by analyzing the interface behavior between the two fluids. Over time, as a well produces, asphaltenes in crude oil function as natural emulsifiers. These compounds can gradually shift the formation from a water-wet state to mixed-wet or even oil-wet conditions, while also promoting stable water-in-oil emulsions that limit efficient oil displacement from the wellbore

In formations that have become mixed-wet or oil-wet, acid systems without surfactants often struggle to penetrate scale or formation damage because hydrocarbons coat rock surfaces and restrict effective acid contact (Figure 1).

To address this challenge, several multipurpose surfactants have been developed in recent years. These products are typically formulated with a blend of solvents, low surface tension agents, suspending agents, and retarders. The solvents dissolve and remove hydrocarbon coatings from formation and scale surfaces. Low surface tension agents help break water-in-oil emulsions and enhance acid penetration. Retarders slow the acid reaction rate, allowing for deeper penetration and increased contact time within the formation. Suspending agents capture and transport fines generated during the treatment, minimizing re-deposition and aiding in their removal from the wellbore (Figure 2).

By incorporating a multipurpose surfactant into the acid system, operators can significantly improve acid contact and stimulation efficiency. In a study of 329 acid stimulation treatments, the addition of a multipurpose surfactant resulted in an average 82% increase in BOPD compared to treatments performed without one. [1]

An acid compatibility test is essential to ensure the selected acid system does not create emulsions or precipitate sludge that could cause formation damage. At a minimum, every acid system should contain three key additives: a corrosion inhibitor, a non-emulsifier, and an iron control agent.

To replicate downhole conditions as closely as possible in the laboratory, 50 mL of crude oil should be heated to the well's bottomhole temperature and mixed with 50 mL of the proposed acid system. The acid should contain 5,000 ppm of dissolved iron, blended at a 3:2 ratio of ferric (Fe^{3+}) to ferrous (Fe^{2+}) iron to simulate well conditions.

Ferric iron (Fe^{3+}), when combined with crude oil and live acid, can initiate asphaltic sludge precipitation at a pH of approximately 2.2 and continue until the acid is fully spent at a pH near 6. In contrast, ferrous iron (Fe^{2+}) does not typically precipitate asphaltic sludge, but in sour gas wells it can react with hydrogen sulfide to precipitate iron sulfide (FeS). For this reason, iron control additives—or combinations of iron control additives—must be selected based on the primary risk: sludge formation or iron sulfide precipitation.

Iron control strategies typically include chelating agents, reducing agents, and pH buffers. These additives work together to maintain iron in a soluble state and prevent damaging precipitates during the acid treatment. However, certain crude oils with a high tendency to form sludge may also require anti-sludge additives or emulsified xylene blends. These products contain oil-soluble components that stabilize crude oil asphaltenes and prevent precipitation. Proper selection and testing of these additives are critical to ensuring that the acid treatment enhances production without introducing additional formation damage.

Scale inhibitors are often overlooked and not routinely incorporated into acid stimulation treatments. The absence of scale inhibitors during acid treatments may limit the longevity of production gains, as scale dissolved during the treatment can rapidly re-precipitate without adequate inhibition. In the Permian Basin, research evaluating the use of scale inhibitors in conjunction with acid stimulation is relatively limited, presenting an opportunity to explore this approach further. Additional laboratory testing and field trials are needed to evaluate the compatibility of scale inhibitors with acid systems and to determine their effectiveness in extending the longevity and overall success of acid treatments.

DIVERSION

With the majority of acid stimulation treatments now performed on 1–3 mile laterals, effectively distributing acid across extended lateral sections remains a significant challenge. Treatments pumped without diversion — or with an inappropriate diversion method — risk stimulating only a limited portion of the pay zone, thereby restricting potential production uplift.

Each diversion strategy must account for a range of operational and reservoir variables, including pump rates, clustered perforation designs, wellbore integrity, bottomhole temperature, formation permeability, and the extent of formation damage.

A comparison of the various diversion techniques — including associated costs, effectiveness, and risks — are summarized in (Table 1). Detailed breakdowns of individual diversion methods are presented in (Graphs 2–5).

JOB DESIGN

Acid stimulation designs can vary significantly in size and complexity depending on an operator’s key performance indicators (KPIs), which may include return on investment (ROI), 30-day production uplift, or long-term treatment longevity. The selected KPI, along with the approved budget, directly influences acid volumes, surfactant selection, diversion strategy, pump parameters, and pre- and post-flush design. It is therefore critical that service providers operationally deliver the necessary components—including acid volumes, acid system design, pump schedule, and stage optimization—in a manner that directly supports the operator’s defined performance objectives.

Optimal acid stimulation volumes for carbonate formations should follow established treatment guidelines. Recommended design ranges include 10–25 gal/ft for wellbore cleanout treatments, 25–50 gal/ft for near-wellbore stimulation, 50–150 gal/ft for intermediate matrix stimulation, and 150–500 gal/ft for extended matrix acidizing treatments.[2] These volume ranges provide a framework for aligning treatment intensity with the desired level of skin reduction and stimulation effectiveness in carbonate reservoirs.

Acid system selection should follow established quality assurance and quality control (QA/QC) protocols outlined in the treatment chemistry formulation section and must be integrated with the most appropriate diversion method for the specific reservoir conditions. Proper fluid selection, additive compatibility, and diversion strategy are essential to achieving uniform zonal coverage and effective wormhole propagation.

Once acid system volumes and diversion strategy are established, the next step in job design is determining the achievable pump rate and anticipated treating pressures under the well's current conditions. After rate and pressure constraints are defined, acid and diversion stages should be optimized to ensure effective distribution of the acid system as far radially as possible, particularly in horizontal wells. Best practice is for acid stages to outnumber diversion stages by one, beginning and ending the treatment with acid. Depending on the diversion method used, water spacers may be required following diversion stages to allow diversion materials to fully respond before additional diversion is pumped. All design details, including stage sequence, pump rates, volumes, and estimated pump times, should be clearly documented in a comprehensive pump proposal to ensure proper execution and alignment with treatment objectives.

Once all necessary equipment is identified, standard operating procedures must be established to ensure the job is executed safely.

CONCLUSION

Historically, acid stimulation treatments have often delivered short-term production increases, but these gains frequently declined within the first 30 days as production returned to pre-treatment trends. However, recent advancements in treatment design and candidate selection suggest that modern acid stimulation practices may be capable of delivering more durable production results.

First, acid treatments are now pumped at significantly higher rates, typically ranging from 8 to 50 BPM—compared to historical rates of 3 to 10 BPM. These higher pump rates allow greater volumes of acid and diversion materials to be distributed more effectively across long horizontal pay zones. When combined with effective diversion techniques, higher rates help ensure that acid is placed more uniformly throughout the interval, improving stimulation coverage.

The second factor is the use of multipurpose surfactants designed to enhance acid penetration in mixed oil/water or oil-wet formations. These surfactants improve fluid interaction with the formation, allowing the acid to contact and react with the rock more efficiently. The third and most critical factor is the systematic selection of suitable well candidates for acid stimulation treatments since comprehensive candidate screening significantly improves the likelihood of achieving effective and sustained production enhancement.

Lastly a well-designed acid stimulation treatment can deliver significant and sustained production improvements when all key variables are properly addressed. As shown in (Table 2), six acid treatments were monitored for more than 200 days following the acid stimulation treatment. These wells demonstrated an average production uplift of approximately 58 BOPD after 200 days, highlighting the potential effectiveness and durability of properly engineered acid treatments. [3] These results suggest that modern acid stimulation practices, when carefully designed and applied to appropriate well candidates, can provide meaningful and durable production enhancement in mature Permian Basin wells.

Figure 1. Acid Penetration Limitations in Oil-Wet Formations

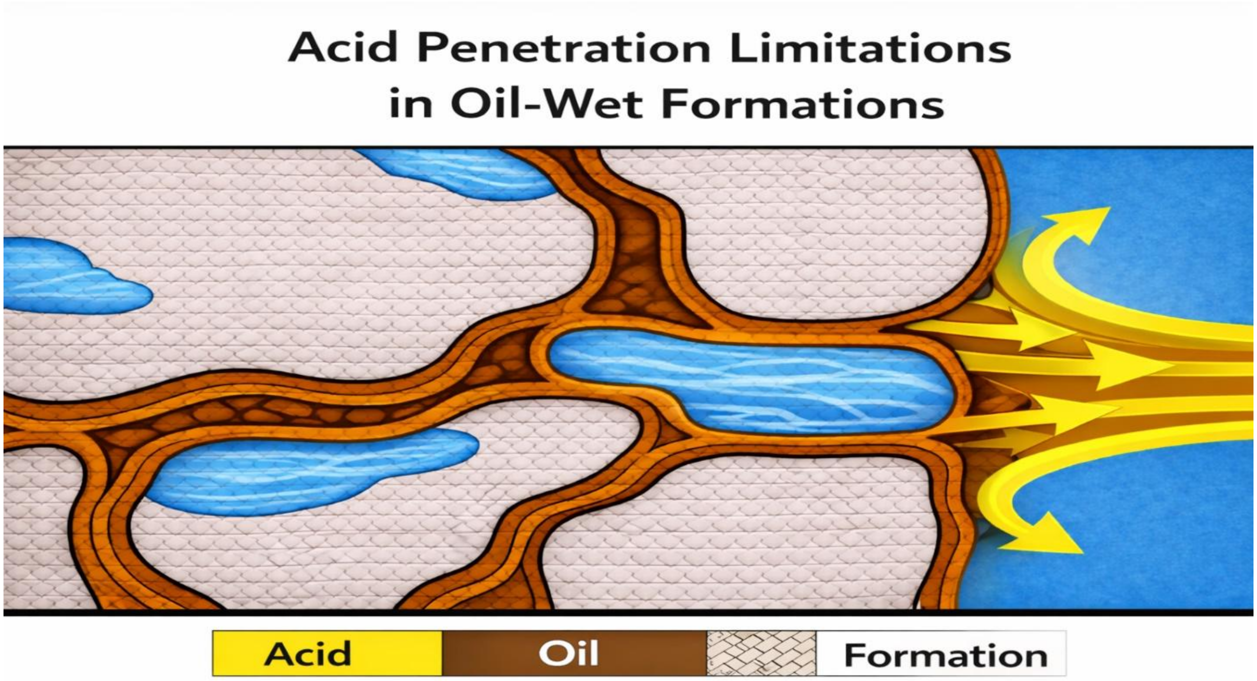

Figure 2. Multipurpose Surfactant Performance in an Oil Wet Formation

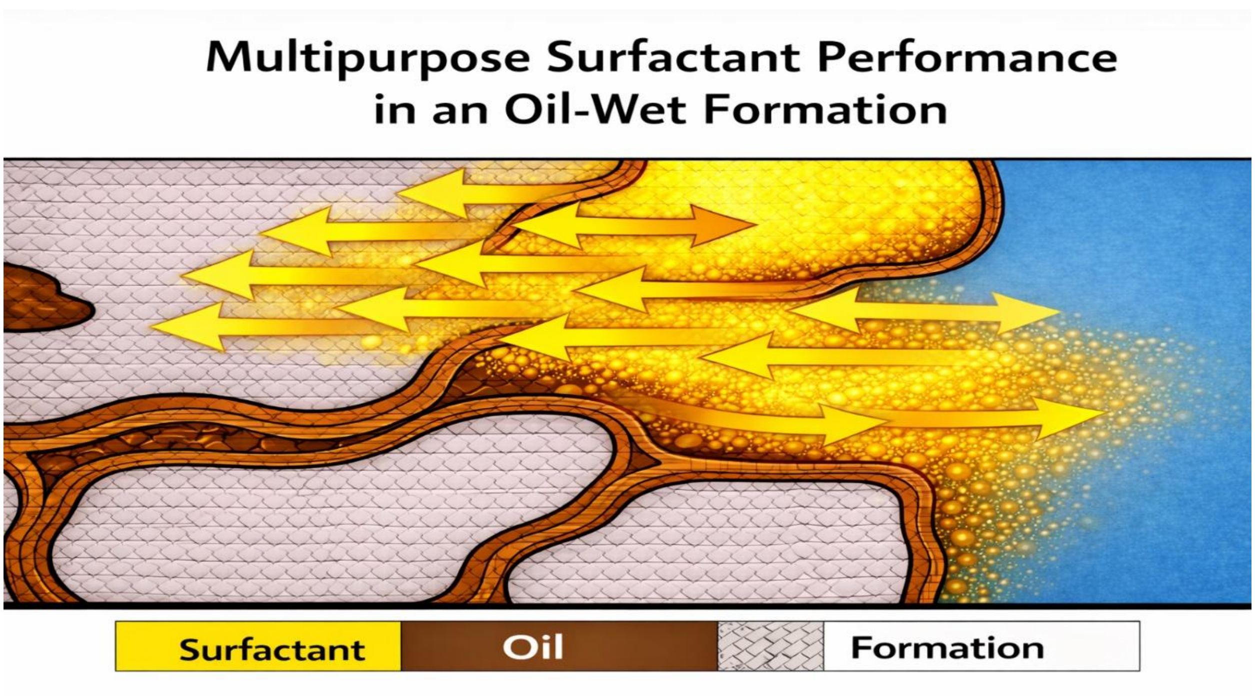

Table 1. Comparative Evaluation of Diversion Methods for Horizontal Acid Stimulations

Diversion Method	Cost	Efficiency	Technical Limitations
High-Rate Injection (<20 BPM)	$$	Low	Heel-dominant stimulation; insufficient acid distribution along extended laterals
Gel Pills	$$	Moderate	Viscosity degradation above 160°F reduces diversion reliability
Biodegradable Ball Sealers	$$$	Low	Inefficient seating in enlarged perforations or closely spaced clusters
Rock Salt	$$$	Moderate	Placement uncertainty, gravity settling, and reduced effectiveness at low pump rates (<8 BPM)
Self-Diverting Acid (SDA)	$$$	Very Low	Limited applicability in long horizontals; primarily suited for short vertical intervals
Polylactic Acid (PLA) Diverters	$$$	Moderate	Higher material cost restricts treatment volume and diversion coverage
Perforation Pods	$$$$	Moderate–High	Elevated cost and operational deployment complexity
Pin-Point Injection Systems	$$$$	High	Risk of downhole tool obstruction or mechanical interference within lateral sections

Graph 3. Diversion Performance for a 9-Stage Treatment with 267 lbs. of PLA per Stage

Graph 4. Diversion Performance for a 5-Stage Treatment with 5,000 lbs. of Rock Salt per Stage

Graph 5. Diversion Performance for a 5-Stage Treatment Using 24 bbl. Gel Pills

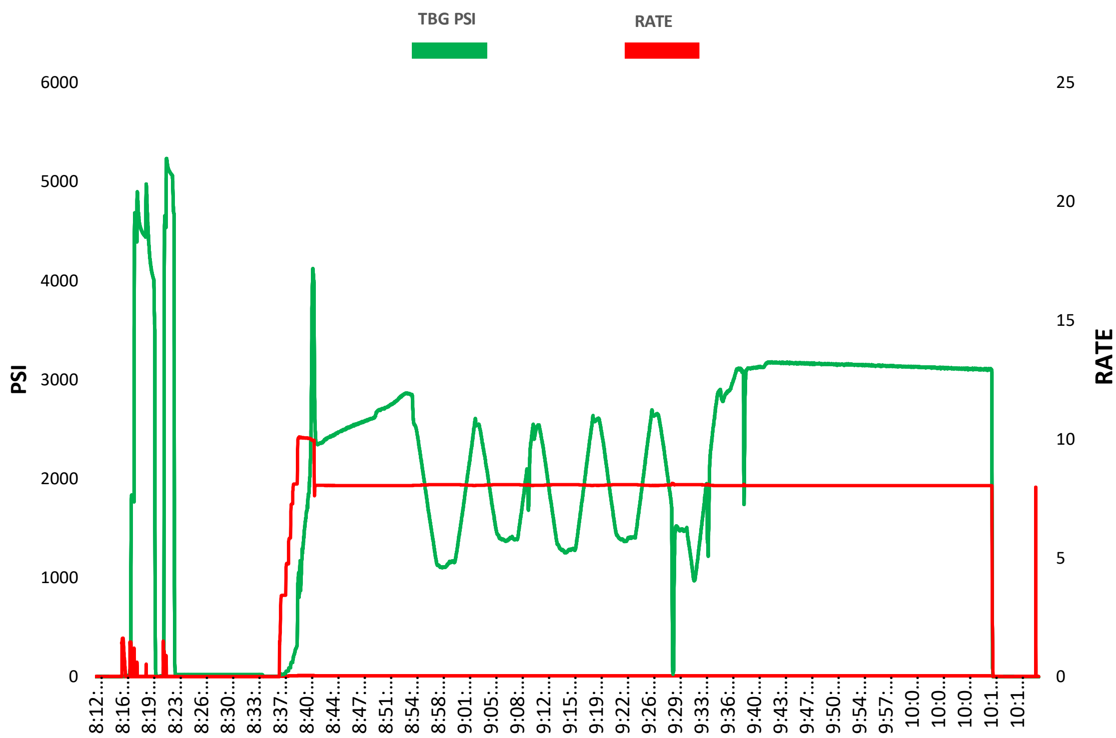

Table 2. 6 Wells Treated with a Multipurpose Surfactant and Gel as Diversion

Well	Uplift at Average 200 Days RTP					
	BOPD	BWPD	MCFD	PIP	BFPD	Incremental Oil Uplift Percentage
A	101	465	411	374	565	152%
B	131	-137	300	636	-6	286%
C	42	83	478	0	125	70%
D	26	511	11	-65	537	44%
E	42	189	302	439	231	130%
F	6	194	-89	359	200	17%

*Cleanouts were performed on Well B & F

*Acid treatments were conducted during ESP replacement operations, while ESP on the remaining wells were downsized.

References:

1. Enverus. 2026 *Drilling Info Production Database.* Enverus, Austin, Texas Accessed 2022-2024
2. Halliburton. 2008. *Carbonate Matrix Acidizing Treatments.* Halliburton, October 2nd
3. Chalfant, E. and Cunningham, K. 2025. *Enhancing Production in Permian Oil Wells Using Acid Diverter*. Presented at the Southwest Petroleum Short Course Conference, Lubbock, Tx, 4/23/25.