Continuous Improvements in Acid Fracturing at Lake Maracaibo

The Maraca limestone formation is a part of the Cogollo carbonate group below Lake Maracaibo, Venezuela. Acid fracturing with an organic-acid system has proved to be a pivotal completion strategy for achieving higher productivities and increasing reserves. The main challenges are the relatively high hydrogen sulfide (H₂S) content, 280°F reservoir temperature, the asphaltene nature of the crude, and the long completion tubing that limits pump rate.

Introduction
The Maraca limestone formation is a 20- to 30-ft upper member of the Cogollo carbonate group at 15,000 to 16,000 ft in the Urdaneta West field below Lake Maracaibo, Venezuela. Reservoir volumes and productivity are attributed mainly to matrix development, in contrast with the rest of the Cogollo, where natural fractures play a major role in well production.

When stimulation and development strategy began focusing on the Maraca group, a number of matrix stimulations were performed, most using coiled tubing (CT) at low pumping rates and volumes. The first few treatments used 15% hydrochloric acid (HCl), but the acid system was switched quickly to an organic acid blend (13% acetic and 9% formic) because of the high reactivity of the HCl and its tendency to form sludges after contacting the asphaltene Maraca oil. These matrix treatments had modest results, and the gained productivity was lost after a few months of production.

Acid Fracturing With Organic Acid
Acid fracturing was considered as an alternative to stimulate Maraca wells. Not only would acid fracturing increase well productivity, but it also would help retain the generated conductivity for a longer time period. Acid fracturing is a stimulation technique where acid, usually HCl, is injected into the reservoir at fracturing pressures. As the acid flows along the fracture, the fracture face is dissolved in a nonuniform manner, creating conductive or etched channels that remain open when the fracture closes. The effective fracture length is a function of the type of acid used, the acid reaction rate, and the fluid loss from the fracture into the formation.

Acid fracturing was preferred to hydraulic fracturing because proppant cleanout in a sour well with CT required operational and safety resources not yet in place. Additionally, the high conductivity of an acid-etched fracture made acid fracturing a more attractive technique if comparable fracture lengths could be achieved.

Organic acid was selected rather than HCl to provide a more retarded acid, minimize asphaltene-flocculation potential, and provide less costly corrosion inhibition at 280°F. Thirteen jobs were performed with this organic acid blend of 13% acetic and 9% formic acids, which has approximately the same dissolving power as 8% HCl. The acid-fracture stages had a polyacrylamide gelling agent for friction reduction, retardation, and fluid-loss control. Treatments were executed at 16 to 18 bbl/min average pump rate with a maximum pressure of approximately 10,000 psi during the acid-fracturing stages. A closed-fracture acidizing (CFA) stage then followed at 2 to 4 bbl/min with approximately 220 bbl of ungelled organic acid. Fracture gradients for the wells varied from 0.78 to 0.86 psi/ft. A typical treatment procedure pumped a total of 880 bbl of organic acid in four stages.

The treatment was staged, pumping three pad stages to control leakoff, increase etched length, and maintain net pressure inside the fracture. The CFA stage followed the main treatment in an effort to increase generated conductivity. If the acid etching along the fracture face is uniform, the retained conductivity after the fracture closes can be very low. In the CFA stage, ungelled acid is injected at pressures less than the fracture gradient to maximize the conductivity of the channels created during the acid-fracture stages and help retain sufficient conductivity after the job.

After completion of this first campaign, the potential of acid fracturing was evident because of the 110% average increase in productivity. It was evident that the gained productivity was sustainable over time even with the relatively high (4,000 to 6,000 psi) effective closure stresses on the etched fractures. Exceptions were the wells with high asphaltene-deposition pressure that were damaged when the flowing bottomhole pressure dropped below this critical pressure, resulting in asphaltene dropout. This generated-conductivity sustainability can be attributed to the competence of the formation rock, which has a Young’s modulus in the 5 to 7×10⁶ psi range.

Even though the organic-acid fracturing campaign was very successful, effectively doubling the reservoir production in 2 years, computer simulations indi-
cated effective half-lengths of only 50 to 100 ft, suggesting there was potential for additional productivity improvement with a more-retarded system.

Encapsulated citric acid was viewed as an alternative to achieve longer etched length, and a full-scale trial was performed with disappointing results. Parallel to this effort, a new model for organic-acid spending was developed that showed that effective lengths greater than 150 ft were achievable with an organic-acid system. Simulation results showed that for the average Maraca well with 20- to 25-md permeability, fracture lengths greater than 150 ft would increase production only marginally, but significant gains could be realized if fracture conductivity could be increased.

Dissolving Power

Addition of HCl to the organic blend used in the first campaign was seen as a way to increase acid dissolving power and effective conductivity without sacrificing length obtained with the previous system. 5% HCl was incorporated into the blend and tried in three wells (two of which were refracture treatments) to verify the potential to improve productivity indices (PIs) achieved with the original blend. From the results of these refractures, it was apparent that wells with permeabilities of approximately 7 md and less were likely to have sufficient etched length and conductivity already and were not candidates for retreatment unless the original productivity had deteriorated over time.

The response from one of the refractured wells validated the theory that additional gains could be achieved in moderate-permeability wells (15 md and greater) with higher effective conductivities, but this blend increased treatment costs, and approximately 85% of the acetic acid was unable to react at downhole conditions because of the buffering effect of the three-acid system.

Third-Generation System

Three factors were identified as key for maximizing the effective conductivity of the etched fracture: dissolving power, acid-leakoff control, and pump rate. Higher dissolving power should increase retained conductivity if etching is sufficiently heterogeneous. In the case of the Maraca formation, natural formation heterogeneities and 1 to 2% kaoline irregularly coating the limestone increase conductivity retention after fracture closure. If acid leakoff is too high, the acid can be lost to the formation through the first few feet of the created fracture, resulting in shorter etched lengths. Additionally, the acid that leaks off into the formation is spent away from the fracture face where conductivity is generated. Separate studies were undertaken to address these key issues and develop a third-generation system that could make the most of the moderate- to higher-permeability wells.

HCl/Formic Acid. During the evolutionary process to optimize the acid system, it became clear that the two most important requirements were a high carbonate-dissolving capacity and deep acid penetration to achieve a long etched length. Another requirement was that the acid could be inhibited adequately at downhole conditions. This led to development of a 7% HCl/11% formic acid system. Acetic acid was removed from the blend because of incomplete spending downhole. A high carbonate-dissolving capacity was obtained by adding 7% HCl. The HCl/formic acid blend has dissolving capacity equivalent to 14% HCl at downhole conditions. A second reason for adding HCl was to improve conductivity in the near-wellbore part of the fracture. The HCl was limited to 7% to avoid sludge formation on contact with reservoir fluid. The formic acid in the blend starts spending only after most of the HCl is consumed. Thus, the formic acid penetrates deeper into the fracture, resulting in increased etched length. Formic acid concentration was set at 11%. Although a higher concentration may improve carbonate-dissolving capacity, the risk of calcium formate precipitation is increased.

Gelling Agent. To maximize etched-fracture length, live-acid leakoff or loss from the newly created fracture face into the formation must be managed. The more control, the higher the fluid efficiency and the greater the amount of live acid transported toward the fracture tip. A common technique to manage the live-acid leakoff is use of gelling agents. The most common gelling agents are polymer based. More recently, surfactant-based self-diverting acids have been introduced. The chemistry and mechanism of leakoff control are similar to polymer systems in that the trigger for crosslinking is the reaction with the carbonate formation. However, the pressure required to initiate flow after treatment with polymer-based gelled-acid systems is significantly higher than that required for surfactant-based systems. In this third acid-fracturing campaign, the surfactant-based system was chosen instead of a gelled acid or self-diverting crosslinked acid.

Field Results

Productivity. The new formulation was tested in the field in new and previously fractured wells. After successful results on the first few wells, all the wells with at least 15-md permeability were refractured with the new formulation and it became the standard for all wells. A total of 13 wells was treated in the third campaign, eight of which were refractures executed to increase the PI and not because of significant productivity decline over time. The only well where the PI was not increased was Well E. This well has the lowest permeability-thickness product of the group, and it is likely that the conductivity achieved with the first system was already close to the technical limit. The 35% average increase in productivity led to record production levels in the field and proved the merit of reformulating the acid-fracturing system.

Pump Rate. Besides changing the acid and the gelling agent, higher pump rates were used in the third campaign. Pump rate was increased 30 to 50%, and this factor, in theory, also could have played a role in the higher productivity obtained. However, there is not a clear and conclusive trend, and more field data are required to establish the benefit of higher pump rates.

Closure Pressure. Another factor that could have played a role in the higher PIs of the retreatments with the HCl/formic acid system was the lower effective closure stresses at the time of the refractures. On average, the effective closure pressures were 1,000 psi lower at the time of the treatments; but for Wells G and H, the stresses were almost the same and their productivities still increased.

The data suggests that the more aggressive and significantly improved leakoff control provided by the new gelling agent were the key factors that led to higher fracture conductivities.
and production. The interpretations of pressure-transient data show that the retained fracture conductivities are considerably higher than those obtained with the previous system or that there is an additional pressure drop resulting from skin that is considerably higher for the conventionally gelled systems.

Another interesting finding after the evaluation of the organic and HCl/formic acid campaigns was that for most cases, the fluid-loss coefficient estimated after the calibration tests increased after the first fracture. The fluid used for all the tests was the same brine, and the tests were performed before the acid treatment. Data suggest that the second treatment reopened the same fracture, and the local permeability of the fracture faces was increased significantly by acid leakoff from the previous treatment. This is a factor that would make refracturing more challenging and makes acid leakoff control even more relevant to avoid excessive leakoff that leads to shorter etched lengths.

**Net Pressure Behavior.** Four of the wells treated in these campaigns were equipped with permanent downhole gauges. Pressure data taken during the treatment provide some insight into fracture development and leakoff behavior. Fig. 15 in the full-length paper shows the downhole treating pressure for Well Q for the acid-fracturing stages of the stimulation. There is a sudden 200-psi net pressure loss when the first acid stage gets to the formation, which suggests a sudden significant increase in fluid loss. This net pressure-loss trend decreases after that, probably caused by the increased viscosity of the acid upon spending. The plot also shows that the intermediate pad stages have only a minor effect on the net pressure, and while they lower the net pressure-loss trend as they enter the fracture, this effect is lost rapidly once the subsequent acid stage enters the fracture. There are no downhole data available for the treatments conducted in the first and second campaigns for comparison.

**CFA.** After fracture closure, CFA followed all the treatments, injecting ungelled acid at pressures below fracturing pressures in an attempt to increase the conductivity gained after the acid-fracturing stages, especially in the near-wellbore area. However, the effect of the CFA stage on final productivity is not clear from the pressure data.

**Conclusions**

1. The acid-fracturing experience in the Maraca formation confirms that in many instances, significantly better field-tailored solutions can be obtained with proper laboratory testing and field trials of various alternatives.

2. The equivalent pseudoradial skins achieved after acid fracturing the Maraca formation with a combination of HCl and formic acid are consistently between $-5$ and $-7$ and close to the technical limit.

3. Higher fracture conductivities, and not longer fractures, were the key in the Maraca refracturing-campaign success.

4. An optimum acid blend combines a high carbonate-dissolving capacity with sufficiently deep acid penetration.

5. In the Maraca wells fractured with the HCl/formic acid system, CFA-stage benefits were not evident following the acid-fracturing stages.