La opción de estimulación con la técnica de interdigitación aplicada en yacimientos carbonatados impregnados con aceite pesado

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Resumen

Los yacimientos carbonatados impregnados con aceite pesado son complicados de producir. Este tipo de yacimientos de carbonatos presentan una variedad de retos en la fase de terminación de pozos y en el diseño de estimulación y otras técnicas de mejoramiento de producción, pues frecuentemente presentan espesores considerables con un amplio rango de permeabilidad natural. En México, los ingenieros de terminación y estimulación deben considerar todos estos factores en la elaboración de los diseños correspondientes y seleccionar las tecnologías apropiadas para estimulación, para optimizar la producción y recuperación de hidrocarburos.

Una opción válida para tratar estos yacimientos complejos es la técnica para estimulación por interdigitación. La situación se complica más cuando el yacimiento está saturado con aceite pesado. Los yacimientos carbonatados se estimulan primordialmente con ácido clorhídrico apoyado con ácido acético para limpiar e inducir conductividad en la formación, mitigando o eliminando los daños presentes en el yacimiento.

La tecnología de estimulación por interdigitación se basa en el desplazamiento de un fluido estimulante viscoso por otro mas ligero o menos viscoso, a través de un medio poroso. El fluido delgado en viscosidad tiende a formar "dedos" dinámicos a través de los canales de flujo, de ahí el término de interdigitación.

El fenómeno de interdigitación por diferencia de viscosidad en conjunto con su procedimiento de inyección maximiza el área y tiempo de contacto entre los fluidos estimulantes y la formación, siendo estas circunstancias esenciales para inducir una conductividad óptima y longeva; es decir, patrones de grabado del yacimiento por efectos de la reacción ácido-carbonatos que facilitarán el flujo de aceite pesado del yacimiento al pozo, eliminando los principales daños presentes en el yacimiento tratado.

Por otra parte, se agregan y mezclan con los sistemas ácidos estimulantes aditivos especiales, como solventes/surfactantes para proporcionar movilidad y reducir viscosidad natural del aceite pesado y consecuentemente incrementar productividad.

Este artículo técnico examina los procedimientos de la técnica de estimulación por interdigitación, analiza diseños aplicados en México en carbonatos saturados con aceite pesado, en campos en tierra y en mar, revisando casos históricos, resultados de producción y predicciones y tendencias en el desarrollo de esta técnica novedosa de estimulación para yacimientos carbonatados.

Palabras clave. Interdigitación viscosa, técnica, estimulación, aceite pesado, conductividad, daño.

Viscous fingering stimulation option applied on heavy-oil carbonate reservoirs

Abstract

Heavy-oil carbonate reservoirs are complicated to produce. Heavy-oil saturated fractured limestone formations present a variety of completion, stimulation and production challenges because they commonly contain thick completion intervals with extreme permeability ranges. In Mexico, completion and stimulation engineers must consider these complexities during the design stage and when selecting appropriate stimulation technologies to optimize production and hydrocarbon recovery.

A valid option to treat these complex reservoirs is the viscous fingering stimulation technique. The situation is further complicated when the reservoir is saturated with heavy-oil. Carbonate reservoirs are stimulated using acid-predominantly hydrochloric acid (HCl) strengthened with organic acetic acid to create conductive pathways from the reservoir to the wellbore, and to bypass the wellbore region that has been damaged during drilling and cementing.

Viscous fingering stimulation technique involves the displacement of a more viscous fluid by a less viscous fluid in porous media, the less viscous fluid tends to form fingers into the flow channel, hence the term viscous fingering. The viscous fingering acid injection technique maximizes acid contact time with reservoir faces and is essential to create long and highly conductive etched pathways to facilitate the viscous and heavy-oil flow from the reservoir to the wellbore, eliminated the main damages present in the treated reservoir.

Also, solvent/surfactant special additives are mixed then with acid system designed to stimulate heavy-oils wells for increased productivity. This article examines the viscous fingering stimulation procedures and designs performed in Mexico on heavy-oil carbonate reservoirs, onshore and offshore, reviewing historic cases, production results and the development and trends in the short and medium term.

Keywords. Viscous fingering, technique, stimulation, heavy-oil, conductivity, damage.

Introduction

Acid-fracturing techniques are also used in areas where the natural permeability of carbonate reservoirs is insufficient to promote effective matrix acid stimulations. The goal in carbonate reservoir stimulation is to effectively treat all latent productive zones, reducing formation skin and improving productivity, improving heavy-oil mobility. Carbonate reservoir stimulation in reservoirs impregnated with heavy-oil has improved significantly with the application of innovative and special fluids to acidizing.

México has extensive carbonate heavy oil reservoirs that are being developed and produced and appropriate technology needs to be developed to increase recovery in these formations.

Therefore, the successful exploitation of heavy-oil requires careful planning and execution. There are a number of heavy-oil reservoirs whose importance is growing as the conventional resources deplete. Acidizing must be considered among the oldest techniques still in modern use. Acid derive their utility in well stimulation from their ability to dissolve formation minerals and foreign material. The extent the dissolution of these materials will increase well productivity depends on a number of factors, including the acidizing method chosen.

Matrix acidizing is defined as the injection of acid into the formation porosity (intergrannular, vugular, or fracture) at a pressure below the pressure at which a fracture can be opened. The goal of a matrix acidizing treatment is to achieve, more or less, radial acid penetration into the reservoir, cleaning and partially inducing new conductivity. Stimulation is usually accomplished by removing the effect of a formation permeability reduction near the wellbore (damage), by enlarging pore spaces and dissolving particles plugging these spaces.

When performed successfully, matrix acidizing often will increase oil production, without increasing the percentage of either water or gas produced. The length of the radial penetration of a matrix acidizing job and its capability to clean and induce new conductivity depend of the rate of acid reaction with $CaCO_3$, and the fluid loss rate (efficiency). In carbonates, matrix treatments normally employ hydrochloric acid, (HCl).

The high reaction rate of this acid with limestone or dolomite results in the formation of large flow channels, often called "wormholes", with a penetration range from a few inches to a few feet. The creation of wormholes can be described by the ratio of the net dissolution rate of the acid to the convective transport of live acid to the wormhole surface, expressed by the dimensionless Damköehler number.[1]

Figure 1 shows conductive wormholes. This network greatly enhances permeability around the wellbore, providing production increase in many carbonate reservoirs; effective wormholes induction is necessary with heavy-oil presence in the reservoir.

With proper fluid selection, design, and execution, matrix acidizing can be applied successfully to stimulate conventional and naturally fractured carbonate reservoirs, (see **Figure 2**), saturated with heavy-oil.[2]

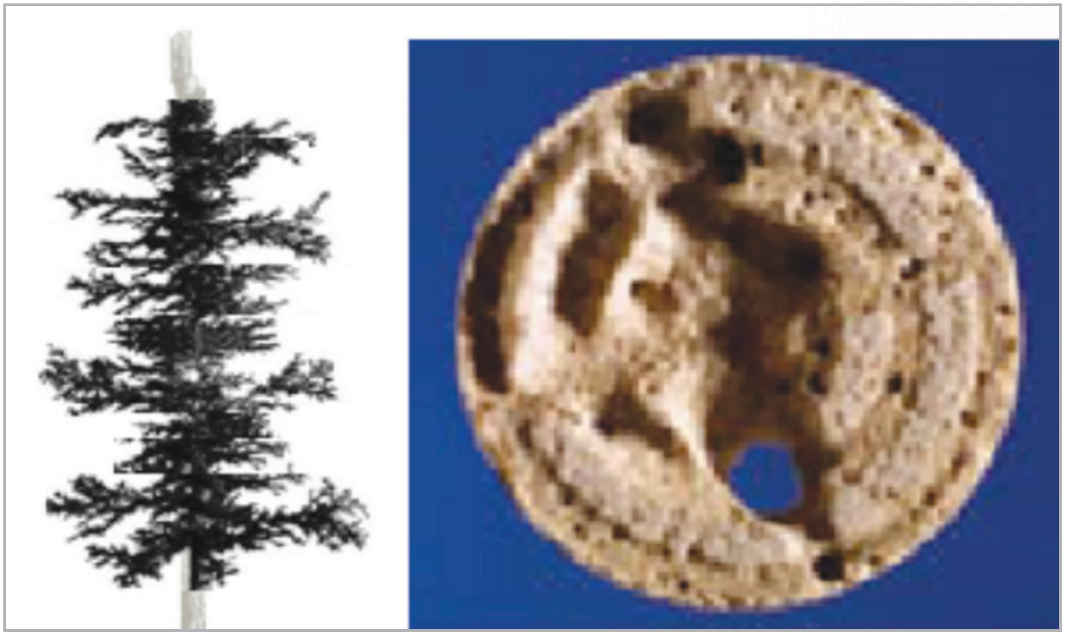

Figure 1. Conductive wormholes.

Figure 2. Naturally fractured carbonates outcrop.

The distance that reactive acid moves along a fracture during the treatment (called the acid penetration distance), is one of the variables that will determine the success or failure of the acidizing job. This distance is controlled by the acid fluid-loss characteristics, the rate of acid reaction with the formation rock, and the acid injection flow rate along the treatment.

The common hydrochloric acid reaction rate in carbonate reservoirs is very high, which is especially important at high bottomhole temperatures. As the bottomhole temperature increases, the reaction rate grows so much, that acid cannot penetrate into the reservoir for more than several centimeters.

Deep penetration of “fresh” acid into the reservoir may be achieved by means of slowing the acid reaction in the reservoir by using emulsified and gelled acid systems; stimulation jobs in heavy-oils carbonate reservoirs should be planned and designed for each well taking into account its specific structure, completion type, formation conditions, and reservoir fluid characteristics.

It is clear that the use of an effective fluid-loss additive in the acid system is central to maximizing the acid penetration distance. Fluid-loss control of acid in carbonates is very difficult. In addition, many carbonates are naturally fractured or vugular and therefore have flow channels that are much harder to plug with an additive. Lab experiments show than an effective fluid-loss can cause acid reaction to be more uniform, producing several wormholes instead of just one.

Because of this limited penetration, matrix treatments in carbonates normally can only bypass near-wellbore flow restrictions and do not create significant stimulation above that achieved from damage removal. In exceptional cases, matrix treatments can give significant stimulation in undamaged wells.[3] This can occur, for example, in naturally fractured formations where acid can flow along existing fractures. Stimulation is achieved cleaning and creating a flow path through a damaged zone around the wellbore.

Effect of Viscosity

Limestone and dolomite formations present tremendous completion, stimulation and production challenges, because they commonly contain thick completion intervals with extreme permeability ranges. Often, they are vertically and laterally heterogeneous, with natural permeability barriers, natural fractures and a vast array of porosity types, from intercrystalline to massive vugular and cavernous porosity.

A gelled acid system with high viscosity is suitable to control fluid-loss. Viscous fluids normally will have a high efficiency, and therefore less fluid is lost to the reservoir. If the fluid-loss rate of an acid can be controlled, it is sometimes possible to use a retarded acid to maximize the distance acid penetrates into the reservoir before being reacted completely.

Gelled acid are commonly prepared by adding polymers such as guar, or a polyacrylamide to HCl. The resulting viscous acid is retarded while it is precisely in the viscous state. The retardation in gelled acids is dependent on time and temperature parameters. Basically, a gelled acid in interaction with a standard acid system with conventional viscosity magnitude is the basic rule for the viscous fingering injection technique.[4]

Viscous Fingering Concept Applied on Heavy-Oil Carbonate Reservoirs

Viscous fingering means induce multiple acid flow channels through a viscous pad acid gel fluid. The all induced conductivities sum is greater than the magnitude of a single conductivity. Wormhole length normally is controlled by the rate of fluid-loss from the wormhole to the formation matrix. The rate of fluid- loss from a wormhole often can be reduced with a fluid-loss additive, thereby increasing wormhole length. In the miscible or immiscible displacement in porous media, the growth of the viscous fingers is believed to be affected by the injection rate, mobility radio and velocity-dependent hydrodynamic dispersion.

To be effective, a fingering acidizing treatment is recommended for heavy-oil carbonate reservoirs; it must react with the rock reservoir to form multiple flow channels that will stay open after the treatment, in addition to the formation damage cleaning.

Flow channels can be formed as a result of a special reaction with the rock surface, or a preferential reaction with minerals heterogeneously placed in the reservoir. The new conductivity induced is influenced by the volume of rock dissolved (sometimes considered as an acid contact time).

The final conductivity created is a direct function of the invasion depth reached by the acid systems injection, and also as a direct function of a viscosity difference between the acid systems injected.

To achieve a successful matrix acidizing job to enhance the production of heavy-oil carbonate reservoirs, three fundamental issues must be addressed:

- Reactivity control
- Fluid-loss control
- Multiple-high conductive flow channels generation and damage cleaning

All above mentioned topics are covered for the viscous fingering technique, **Figures 3, 4 and 5.** Hence, it is essential that the properties of the resource be fully understood before selecting and applying a viscous fingering treatment.

Essential properties include the geological setting; the depth, areal extent, and thickness of the reservoir; oil composition, density, viscosity, and gas content; the presence of bottom water or top gas zones; petrophysical and geomechanical properties, such as porosity, permeability, and rock strength; the presence of shale layers; vertical and horizontal permeabilities; and the variation of these properties across the reservoir.

A good geological knowledge is essential. Also, this matter requires an adequate estimate of the petrophysical properties of the rock and parameters of fluid-rock system that affect productivity, especially oil viscosity and relative permeability.[5]

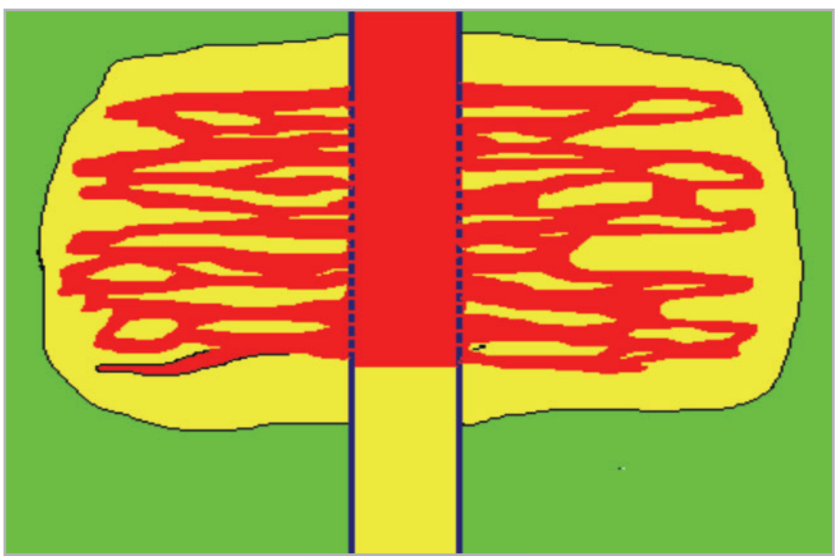

Figure 3. Viscous fingering technique inducing multiple flow channels.

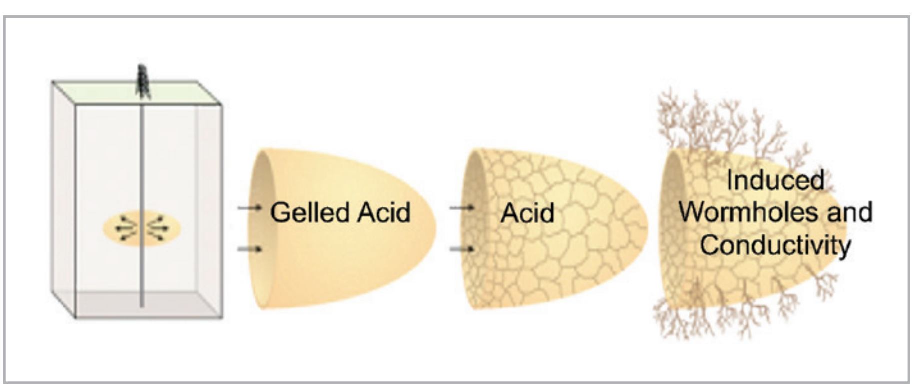

Figure 4. Viscous fingering technique concept.

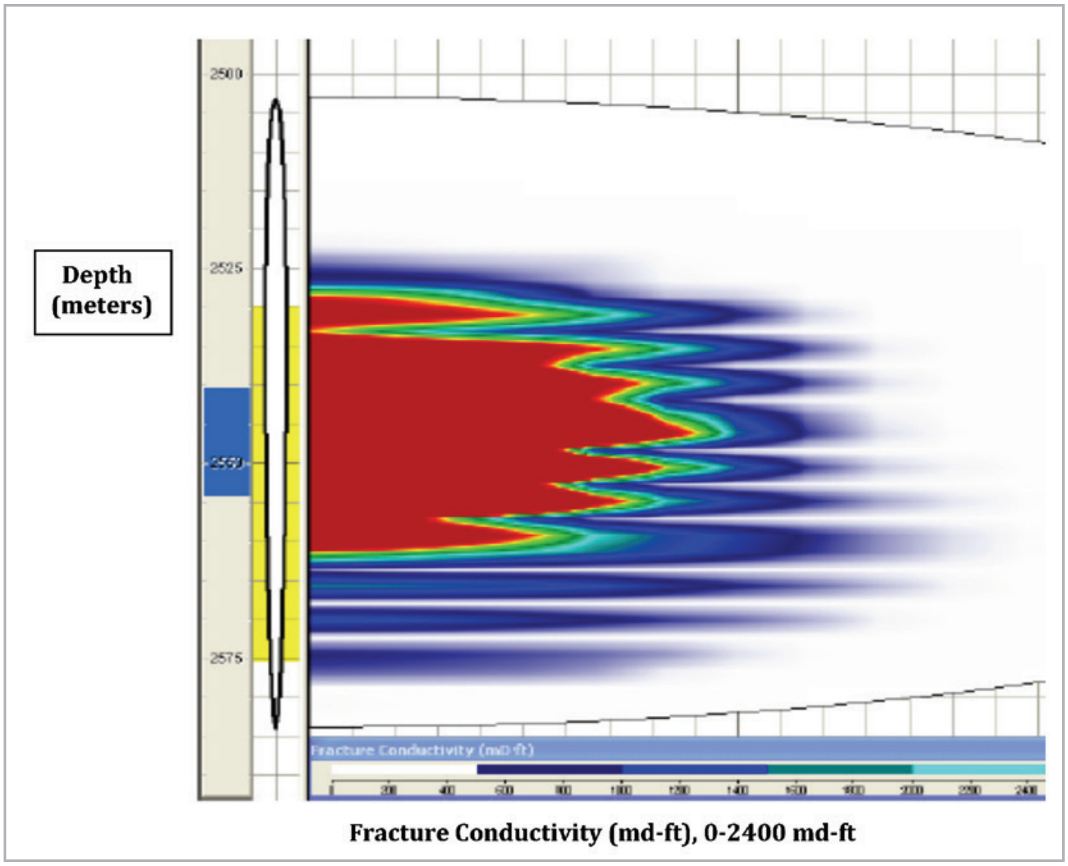

Figure 5. Simulator graphic- fingering development.

Figure 6 illustrates a core treated in laboratory under the fingering technique characteristics, while **Table 1** shows the skin reduction by effect of the acid attack under this technique. Mexico's field applications demonstrate the over-whelming success of this novel technology, and they are shown in this article.

Figure 6. Core treated in laboratory showing an induced flow channel.

Table 1. Simulation output showing skin reduction after acid systems injection.

Reservoir Temperature (°F)	172	Average Reservoir Pressure (psi)	1278
Pore Fluid Permeability (mD)	1.44e+01	Porosity	0.070
Reservoir Viscosity (cp)	1.000	Frac Pressure (psi)	5850
TVD to Top of Open Section (m)	2709	TVD to Bot of Open Section (m)	2777
Acidizing Type	Carbonate	Acid Volume (bbls)	327.3
Avg. Surface Pressure (psi)	495	Max. Surface Pressure (psi)	1544
Initial Skin	30.10	Final Skin	-2.20

Fingering, Mathematical Description and Physical Concept

Viscous fingers form when in a thin linear channel a fluid pushes a more viscous fluid. The instability of the interface results from a competition between viscous and capillary forces. We show here by acting on the viscosity or the surface tension by means of surfactants or polymers that the instability can be modified drastically.

For the two different systems, unlike in the classical system, the width of the finger can go through a minimum and increases with increasing velocity before settling at a plateau value larger than half the channel width. A numerical resolution of the relevant hydrodynamic equations reveals that these large deviations from the classical result can be interpreted in terms of a velocity dependent dynamic interfacial tension for the surfactant system and viscosity for the polymer solution.

In other words, viscous fingering is the formation of patterns in a morphologically unstable interface between two fluids in a porous medium or in a Hele-Shaw cell.[6] It occurs when a less viscous fluid is injected displacing a more viscous one (in the inverse situation, with the more viscous displacing the other, the interface is stable and no patterns form). It can also occur driven by gravity (without injection) if the interface is horizontal separating two fluids of different densities, being the heavier one above the other. In the rectangular configuration the system evolves until a single finger (the Saffman–Taylor finger) forms. In the radial configuration the pattern grows forming fingers by successive tip-splitting.

The mathematical description of viscous fingering is the Darcy´s law for the flow in the bulk of each fluid, and a boundary condition at the interface accounting for surface tension.

Most experimental research on viscous fingering has been performed on Hele-Shaw cells. The two most common set-ups are the channel configuration, in which the less viscous fluid is injected by an end of the channel, and the radial one, in which the less viscous fluid is injected by the center of the cell. Instabilities analogous to viscous fingering can also be self-generated in biological systems. Simulations methods for viscous fingering problems include boundary integral methods, phase field models, etc.

Diverter option use

Matrix stimulation is even more complex when there are multiple interest intervals, with significantly different permeabilities. High-permeability zones preferentially take the acid and leave zones with lower permeability untreated. These untreated intervals mean less production and lost reserves. This nonuniform stimulation can also lead to high drawdown, causing early and undesirable gas and water production.

For these reasons, acid-diverting techniques, both mechanical and chemical, have been developed and recommended to ensure uniform stimulation through the entire formation thickness.

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The increased viscosity of the gel further reduces flow into existing wormholes and fissures within the treated zones, thereby providing effective in-situ acid diversion to unstimulated, low matrix permeability and damaged zones. The viscosity of the spent gelled acid is related to several factors, including temperature, and to the initial percentages of both acid and surfactant.

After a treatment, the surfactant gel breaks down on contact with produced oil, condensate and mutual solvent preflush flowback, or when diluted with produced formation brine during flowback. Viscosity is also decreased independently upon further acid reaction with the formation and pH increase. The viscosity of the spent gelled acid is related to several factors, including temperature, and to the initial percentages of both acid and surfactant. Such operations are impossible without high quality acid diverting systems. Efficiency depends on quality control.

However, many placement and performance problems complicate the acidizing process. Precisely, the viscous fingering injection method examines the use of a new surfactant-based gelled acid system, that is used to create a self-diverting acid stimulation treatment, interacting with the standard acid system to induce fingering.

Additionally, in the acid system design is desirable to incorporate additives to lower the oil formation viscosity and also to prevent asphaltenes and paraffins precipitates;[7] In terms of cost efficiency and process simplicity, the ideal system should be self-diverting and not cause residual contamination. Application of non-polymer viscoelastic acid systems is efficient in carbonate reservoir saturated with heavy-oils, containing several layers or long pay zones.

As far as acid reacts with formation, viscosity of the system in the reservoir increases rapidly minimizing further fluid penetration into the reservoir and causing self-diversion of injected flow, which allows coverage of the entire treated interval and penetration into untreated or low-permeability layers. In case of natural fracturing in the pay zone, a combination of mechanical and chemical diverters may provide the best effect.

Acid chemical retardation

Typical matrix treatments often require low injection rates, and therefore pure hydrochloric acid cannot be used because rapid acid spending-or consumption, severely limits the acid penetration distance. This causes face dissolution and fails to create a wormhole network, long enough to effectively bypass the damaged zone around the wellbore.

For this reason, acid systems often include additives that delay, or retard, the acid´s reaction with $CaCO_3$, thus extending the reaction time. Chemical retardation techniques typically include emulsification, formation of gels, as well as the addition of organic acids and surfactants.

Solvent/surfactant special system as pad fluid

Often in Mexico, prior to the gelled and conventional acid systems injection according to the viscous fingering technology concept, a solvent stage is pumped as pad fluid. This alternative is used in heavy-oil carbonate reservoirs. This system is a solvent/surfactant additive package blended with production brine, to create an effective high flash point treatment pill for remediating heavy asphaltenic oil wells. Often it´s practical to use flushing and displacement fluids before and after the main stage.

This special solvent system provides the following remediation benefits:

- Reduction in heavy oil viscosities that enhances flow thronga smaller pressure drop
- Provide water wet the formation conditions a that increase the relative permeability to oil
- Removing asphaltenes and parafines skin damage
- Clean the reservoir for the initial wormholing induction in the near bore-hole region injecting reactive acids

Fingering, Mexico field applications

Onshore mature well, fingering technology. Table 2 shows a stimulation injection schedule for a heavy-oil fractured reservoir (carbonate), onshore mature well, using fingering technique.

Table 2. Injection schedule - mixed stimulation (organic and acid systems) fingering option.

Stage #	Stage Type	Elapsed Time min:sec	Fluid Type	Fluid Vol (m^3)	Flow Rate (bpm)
1	Preflush		Nitrogen Gas	500.000	
2	Preflush	32:54	Xylene	4.000	1.00
3	Main acid	114:40	HCl 15%	13.000	1.00
4	Diversion	133:32	15% HCl Gelled Acid	6.000	2.00
5	Preflush	146:07	Xylene	4.000	2.00
6	Main acid	187:00	HCl 15%	13.000	2.00
7	Diversion	205:52	15% HCl Gelled Acid	6.000	2.00
8	Preflush	218:27	Xylene	4.000	2.00
9	Main acid	262:29	HCl 15%	14.000	2.00
10	Overflush	290:47	Fresh Water	9.000	2.00
11	Shut-in	311:26	SHUT-IN	0.000	0.00

Offshore well, fingering technology

A carbonated, mixed-matrix stimulation was performed on the well using coiled tubing with the compatible fluid systems.

Location: Tamaulipas, Mexico

Formation: Jurassic San Andrés, (fractured carbonates)

Well Type: Offshore, Horizontal, oil producer

Depth: 12,588 to 12,874 ft (3,837 to 3,925 m)

The injected treatment 75 bbl (12 m^3) of an organic system was, 113 bbl (18 m^3) of 15% HCl retarded with acetic acid, and 50 bbl (8m^3) of diverter-based acid system, followed by an over-displacement of 62 bbl (10 m^3), with a potassium chloride (KCL)-based brine.

This treatment combination took advantage of the live-acid reaction with carbonates impregnated with heavy-oil, to achieve more reservoir penetration. The job was pumped by placing a two-stage carbonate acid treatment (preflush, HCl acid systems, and afterflush) over the horizontal section of the reservoir, to ensure that the gross interval was fully stimulated.

The reservoir was successfully treated and reached a production rate of 1,287 bpd (204 m^3/d) after stimulation with a head pressure of 1,212 psi. A 30% production increase was obtained compared to production before stimulation. **Table 3** shows the specific injection schedule for this offshore well. Note that the gelled acid was pointed-out as diverter. **Figure 7** illustrates graphically the acid invasion profile (radial penetration), simulated with a specific acidizing software.

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Table 3. Injection schedule, two stages, fingering technique, mixed stimulation.

Stage type	Elapsed time min:sec	Fluid type	Fluid vol (m^3)	Flow rate (bpm)
Organic	37:43	Xilene	12.0	2.00
Main acid	18:51	15% HCl	6.0	2.00
Diverter	12:57	Gel Acid	4.0	2.00
Main acid	18:51	15% HCl	6.0	2.00
Diverter	12:57	Gel Acid	4.0	2.00
Main acid	18:51	15% HCl	6.0	2.00
Overflush	31:44	2% KCl Brine	10.000	2.00

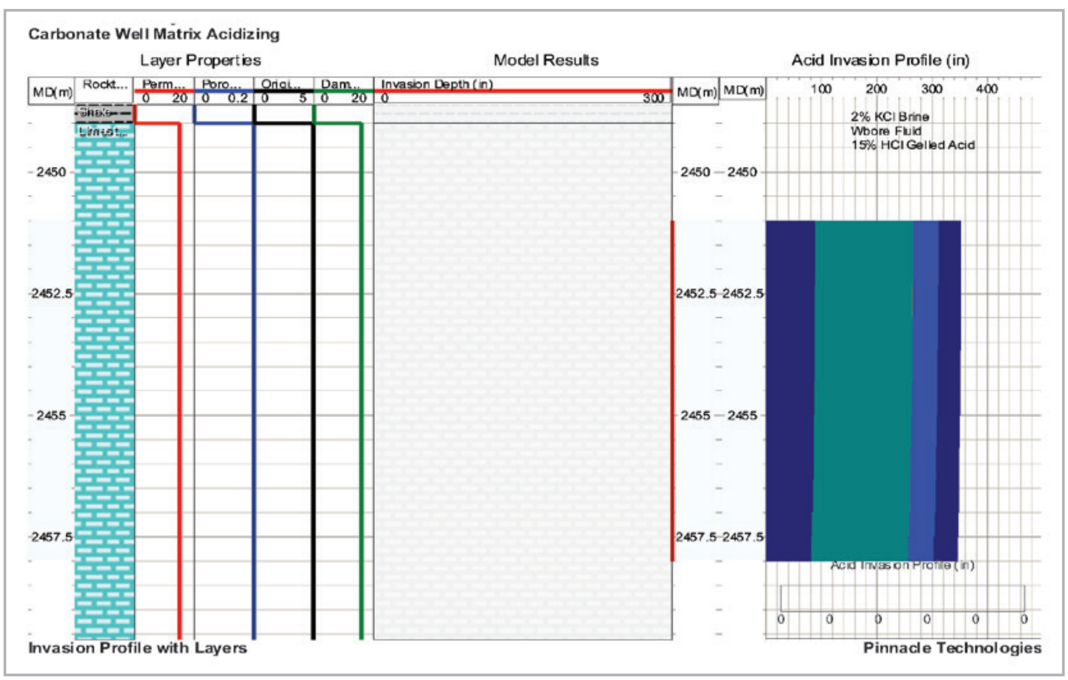

Figure 7. Acid invasion profile-two stages, viscous fingering treatment.

Conclusions

1. Key indicators of successful acid treatment are pay zone coverage and optimum size of permeable channels, specially in heavy-oil carbonate reservoirs targets.

2. Heavy oil is considered an unconventional oil source primarily because it does not readily flow out of the reservoir like conventional petroleum crude oil.

3. There is a large number of technologies than can have an impact, but must be carefully selected, owing to the tremendous variety of heavy and extra-heavy oil resources.

4. Oil producers involved in heavy-oil recovery face special production challenges. However, innovative drilling, completion, stimulation and monitoring techniques help make heavy-oil reservoirs profitable assets.

5. The stimulation development in naturally fractured carbonate reservoirs saturated with heavy oil is making a clear and positive impact on production rates.

6. Fingering technique, and solvent/surfactant special blend system are technologies focused to induce production increase in this type of reservoirs, impregnated with complex oil.

7. Low efficiency in an acidizing heavy-oil treatment impregnated with is a result of poor understanding of the formation conditions, like acid compounds interaction with the rock, saturating fluid characteristics, and insoluble precipitate formed during secondary and tertiary reactions.

8. The problems during an acid job are also associated with poor quality control during preparation and execution of treatment at the well site.

9. Technologies that upgrade value, drive down costs, and reduce environmental impacts, will have the greatest effect on increasing the production of heavy and extra-heavy oil.

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Nomenclature

bbl	- Barrels
bpd	- Barrels per day
bpm	- Barrels by minute
$CaCO_3$	- Calcium carbonate
Ft	- Feet
HCl	- Hydrochloric acid
in	- Inches
KCl	- Potassium chloride
m	- Meters
md	- Millidarcies
MD	- Directional meters
m^3	- Cubic meters
m^3/d	- Cubic meters per day
Np	- Cumulative production
pH	- Potential hydrogen
psi	- Pounds per square inch
TVD	- True vertical depth

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Semblanza del autor

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Ingeniero Petrolero egresado de la Universidad Nacional Autónoma de México. Cuenta con 39 años de experiencia en la Industria Petrolera. Inició su trayectoria profesional en el Instituto Mexicano del Petróleo; trabajó con Halliburton durante 21 años en todo México, alcanzando el puesto de Gerente de Ingeniería a nivel país, (México).

Colaboró en: Corelab de México durante cinco años a cargo del laboratorio, geociencias y ensambles de disparo; en Delta Asesoría como Gerente Técnico durante cuatro años trabajando sistemas artificiales de producción. Laboró también en ACC Ingeniería por dos años, como Gerente técnico de un contrato de estimulaciones.

De noviembre del 2009 a septiembre del 2015 colaboró en Weatherford de México como Ingeniero de distrito en tecnologías de fracturamiento. Asimismo, fue parte de un grupo multidisciplinario de integración y análisis de datos para la optimización de terminación de pozos, estimulaciones, así como de fracturamientos ácidos y apuntalados.

Es miembro de la SPE; ha presentado 18 trabajos técnicos abordando temas de fracturas, estimulaciones, control de agua y arena, sistemas de disparos, cementaciones y terminaciones de pozos petroleros y geotérmicos en diversos Congresos de la SPE, AIPM, CIPM y CFE.

Asimismo, ha impartido talleres de capacitación en prácticamente todos los centros operativos de Petróleos Mexicanos, en la UNAM, el IPN y en diversos foros técnicos de carácter petrolero en Centro y Sudamérica, así como en varios congresos de la industria geotérmica. Es experto calificado en fracturamientos hidráulicos y estimulaciones en pozos petroleros y geotérmicos.