Aplicación de cemento ultrafino en fluido base aceite, en yacimientos de carbonatos naturalmente fracturados: caso de estudio en la Región Sur de México

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Resumen

En la Región Sur de México la producción principalmente proviene de carbonatos naturalmente fracturados, donde la producción de agua se encuentra en el rango de 50 a 90% en algunos casos. Ejecutar tratamientos de control de agua en esta área es un reto mayor debido a que la formación produce a través de fracturas de alta porosidad y alta permeabilidad en pozos profundos de alta temperatura. En el tiempo la técnica de utilizar cemento micro fino bombeado en un fluido base aceite con el fin de aislar las zonas de agua, ha sido implementado como una solución de control de agua preferida. Esta técnica no afecta la zona productora de aceite.

La selección de candidatos para tratamientos de control de agua con cemento microfino en fluido base aceite incluye una revisión del histórico de producción y presión de cada pozo, junto con una revisión del registro de cementación, así como pruebas de admisión trazadas, registros de producción, entre otros, para identificar la fuente del agua.

Es de destacar que en el caso de carbonatos naturalmente fracturados, las fracturas son el medio de porosidad y permeabilidad principal por el cual la producción total es aportada del yacimiento al pozo. En los casos donde la canalización o conificación ha sido identificada, generalmente tenemos que sellar ese medio de producción para lograr un tratamiento de control de agua exitoso. En este escenario es frecuente repetir el tratamiento. La ventaja de este sistema es que sólo aísla el canal preferencial de flujo del agua.

Este artículo técnico describe la curva de aprendizaje para este tipo de tratamiento y también muestra casos históricos relevantes efectuados en la Región Sur de Mexico.

El cemento microfino en fluido base aceite ha sido aplicado para reducir y sellar la producción de agua de carbonatos naturalmente fracturados resultando en una disminución en el corte de agua (tanto como a la mitad del corte de agua inicial el cual varia en un rango de 50% al 90%). Esta disminución en la producción de agua representa una ganancia directa para el cliente.

Palabras clave: Control de agua, yacimiento de carbonatos, naturalmente fracturados, cemento microfino en fluido base aceite.

Application of ultrafine cement into oil-based fluid in naturally fractured carbonate reservoirs: case study in Southern Region of Mexico

Abstract

In the southern region of Mexico the oil production mainly comes from naturally-fractured carbonates where associated water production is in the range of 50 to 90% in some cases. In this area performing conformance treatments is a major challenge because the formation produces through high porosity and high permeability fractures in high temperature deep wells. Over time the technique of using micro fine cement pumped in an oil-based fluid in order to seal the water zones has been implemented as a preferred conformance control solution. This technique does not affect the oil producing area.

The selection of candidates for the oil-based microfine cement conformance treatments included a review of the historical production and pressure of each well, together with a review of the cement bond log, as well as a traced admission test and PLT logs, to identify the source of water.

It is noteworthy that, in the case of naturally fractured carbonates, the fractures sometime provides the essential reservoir porosity and permeability and thus the total production occurs through that pathway to the wellbore. In cases where channeling or coning has been identified, we typically have to seal this production path to achieve a successful conformance treatment. In that case it is frequently necessary to repeat the treatment. The advantage of this system is that it only isolates the preferred pathway for water.

This paper describes the learning curve for this type treatment and it also provides relevant historical cases executed in the Southern Region of Mexico.

Microfine cement in oil-based fluid had been applied to reduce and seal water production from naturally-fractured carbonate resulting in a decrease in water production (as much as half of the original water cut (which initially ranged from 50 % to 90 %). This decrease in water production represents a direct gain for the client.

Keywords: Conformance, carbonate reservoir, naturally fractured, ultrafine cement into oil-based fluid.

Introduction

The primary purpose of conformance treatment is to control or reduce the production of unwanted water or gas. An effective treatment could help efficiently enhance hydrocarbon recovery or satisfy a broad range of reservoir management. However, sometimes, controlling gas or water is a very difficult process because of the extreme reservoir conditions, such as depth, pressure, temperature, etc., and solutions have been continuously moving at different fronts to obtain improved results.

The Delta del Grijalva project is located in the southern region of Mexico. Oilfields Sen and Pijije correspond to this project. Amongst the characteristics of these fields, the high pressure and temperature are some of the most significant issues.

In addition to high pressure (working pressure up 10,000 psi), high-temperature (greater than 300°F or 150°C) environments are present in southern oil fields of Mexico. The existence of naturally fractured reservoirs have made the optimum conformance technique selection highly important during the design of the treatment. Ultrafine cement in oil-based fluids has been used to selectively shut off water intrusion. The system reacts only to the presence of water and can be deployed using bullheading or coiled tubing (CT). This paper discusses experiences with this kind of fluid, as well as optimization. At the current time, changes are intended to provide a more economical water control operation with improved results.

Fields overview

The Delta del Grijalva Production project has been ongoing since 1998. It is located 50 km at the northeastern part of Villahermosa, Tabasco, Mexico. It includes the Frontera, Nacajuca, Centro, Jalpa de Mendez, and Paraiso municipalities. The project area is approximately 1400 km^2; it is integrated into nine fields: Caparroso-Escuintle-Pijije, Cráter, Escarbado, Luna-Palapa, Navegante, Sen, Siní, Terra, and Tizón. These fields have reservoir depths between 5000 to 7000 m subsea (SS) (16,404 to 22,966 ft SS). They are naturally fractured, have high pressure and temperature, and contain associated active aquifers.

The reservoirs are highly geologically complex because of the intense tectonic activity and salinity of the region, **Fig. 1**.

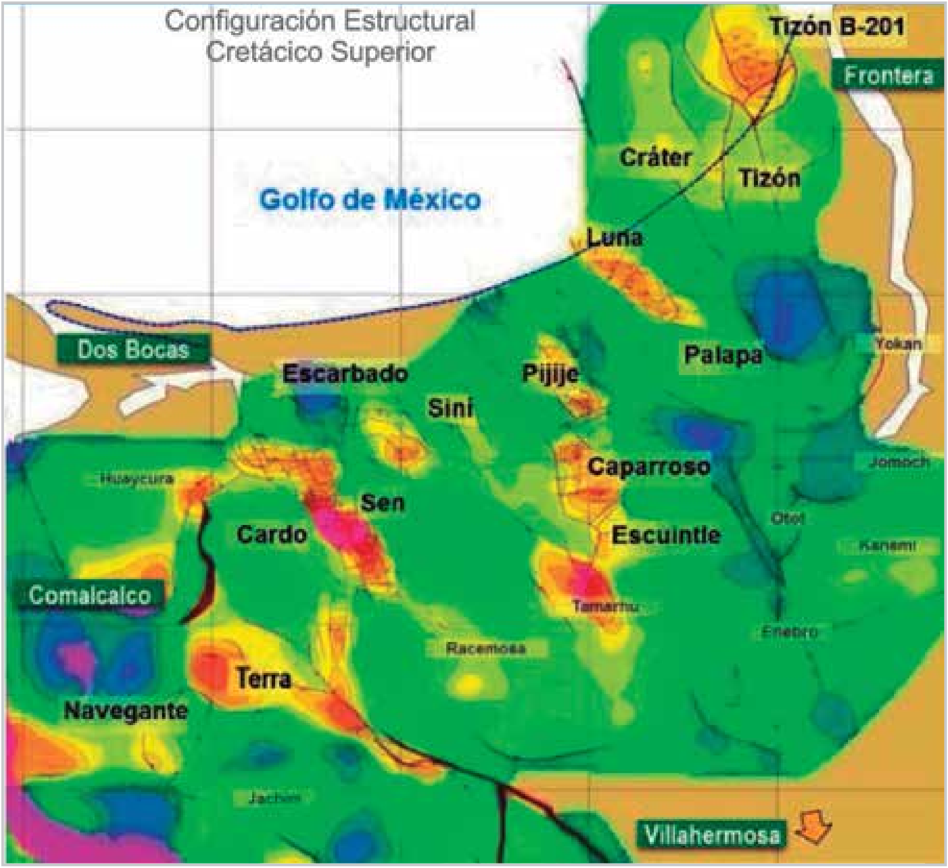

Fig. 1. Location of the fields, (upper cretaceous).

The hydrocarbons produced are volatile oil and gas condensate; these oil gravities vary between 38 and 51°API. Because of its high content of light components, this type of oil is used to enrich the heavier Mexican crude oil for export.

The reservoir has an average porosity of 7%, permeability between 8 to 100 mD, and actual reservoir pressure of approximately 560 kg/cm^2. Another characteristic aspect of the formation is its naturally fractured nature, being primarily approximately 85% carbonate, 7% dolomite, and 8% clay.

The case histories associated with the application of ultrafine cement into oil-based fluid were evaluated in the Caparroso-Escuintle-Pijije and Sen fields. These fields are producers from the Cretaceous formation, with the productive zone being Cretacico Superior (Late Cretaceous) during the time of the conformance jobs, (**Fig. 1**). The challenge encountered during attempts to achieve success post-jobs was to effectively deploy the treatment in this heterogenous reservoir, where, from the beginning, attributed to the presence of natural fractures during the drilling phase, severe loss of circulation occurred. Finally, during the production phase, these same paths contribute to the irruption of water or gas.

Conformance strategy

The use of hydrocarbon-based ultrafine cement slurry was established as the optimal technique to help reduce unwanted water influx for near wellbore (NWB) applications.

Considering that the entire production is believed to be from natural fractures, the application of a nonreactive system within oil or gas zones was necessary.

The conformance problem has two known primary source issues (Halliburton 2002):

NWB problems:

- Casing leaks.
- Channels behind casing.
- Barrier breakdown.
- Completion into or near water or gas.

Reservoir-related problems:

- Coning and cresting.
- High-permeability channeling.
- Fingering.
- Induced fractures.
- Natural fractures.
- Permeability barriers.

In most of the cases, NWB and reservoir-related problems were observed, particularly channels behind casing and natural fractures. The proper placement technique established for optimal results had been bullheading injecting the treatment through the existing tubulars, (Deolarte et al. 2014).

The sequence of the placement was performed as follows:

1. Injectivity test: an injection test is executed before every conformance job to help establish pumping parameters using radioactive tracers within the pumped fluids, such as pressure, rate, and even the admission profile into the intervals or behind the casing. An aromatic solvent, such as xylene, is generally used for this test. The volume, in general terms, is at least the size of the tubing capacity.

2. Packed-off well: if production tubing presents a mandrel or gas injection point across the pipe, the annulus should be filled with an oil-based fluid, such as diesel or xylene, to help prevent the possibility of a reaction between the ultrafine cement and water existent in the well.

3. Solvent preflush: an aromatic solvent with surfactants is pumped before the principal treatment to displace all of the water present in the well and within the NWB to favor the deployment of the cement and help minimize early cement settling. The volume should be sufficient to displace and separate the formation fluids and help prevent a premature settling of the ultrafine cement within oil-based fluid, but not excessive to help prevent the posterior contact and reaction of the system with the formation water.

4. Primary treatment using ultrafine cement within oil-based fluid: after preflushing, the conformance solution is pumped. The volume is variable from case to case. Generally, an initial volume of 30 bbl is considered for an initial intervention; however, this volume is not limitative. It is sometimes common to perform two stages, repeating the entire sequence to achieve an effective seal of the water zone.

5. Overdisplacement: a post-flush nonreactive pill and the displacement with minimum well capacity is necessary to place the fluids.

6. Shut-in time: finally, it is recommended to shut in the well for at least 24 hr after the slurry placement.

Ultrafine cement into oil-based fluid description

The technology considers the slurry during conformance jobs that uses unique ultrafine cement mixed with a hydrocarbon carrier fluid. The slurry remains inactive upon contacting an oil- or gas-producing zone. The system remains inactive until contact with water. Upon contact with water, the slurry remains pumpable for an additional 20 to 30 min before it begins to set. The delayed setting of the cement slurry is ideal for placing the ultrafine cement slurry into water-bearing formations with natural fractures some distance away from the wellbore. The system is applicable up to 400°F (204°C), (Deolarte 2014).

A small average particle size of less than 5 µm helps enable the slurry to penetrate openings as small as 0.05 mm or sands as fine as 100 mesh, without bridging or forming a filter cake during placement. During remedial operations, the unwanted movement of water through casing leaks and formation fractures (either naturally occurring or deliberately produced) is resolved, which might require remedial efforts beyond plugging perforations, holes, cracks, etc. in the casing, cement sheath, and gravel packs, all of which occur within the confines of the wellbore itself.

This makes the slurry ideal for NWB applications, such as:

- Sealing water-bearing formations with natural fractures.
- Stopping unwanted water production from channels and microchannels behind the casing.
- Sealing leaks or pinhole leaks in the casing.

Laboratory tests

One of the key factors to a good field result is the laboratory test. First, it is very important to measure the formation water salinity using a bottomhole water sample. After that, many tests using several hydrocarbon carrier fluids (i.e., diesel or xylene) are run using the ultrafine cement and different dosages of surfactants to achieve the correct rheology and set time.

Fig. 2 illustrates different reaction times using several designs of the ultrafine cement treatment within oil-based fluid. During this test, a slurry of ultrafine cement within oil-based fluid and formation water were mixed at a slurry/water ratio of 90/10.

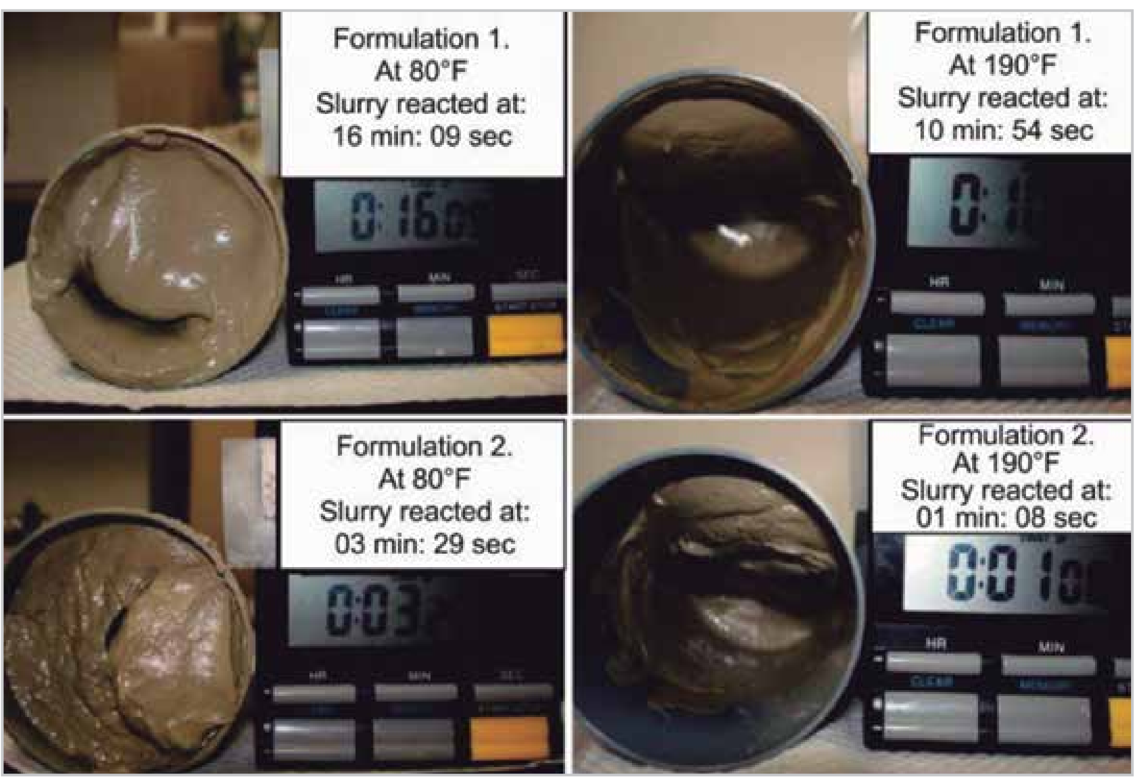

Fig. 2. Different tests varying the surfactant amount.

Case histories: planning and execution

Case history 1: channel behind production liner (Well A)

This well was completed in the Cretacico Superior Méndez, (late cretaceous maastrichtian and campanian) formation throughout two intervals, **Fig. 3**. A production log test was run, confirming a fluid (oil+water) inlet from the two intervals to be the fluid entrance of the lower interval toward the base, with a density of the mixture as 0.67 g/cc. The upper zone indicated a density of the mixture as 0.55 g/cc; this was the entry of fluid from the top of the interval. **Table 1** summarizes these results.

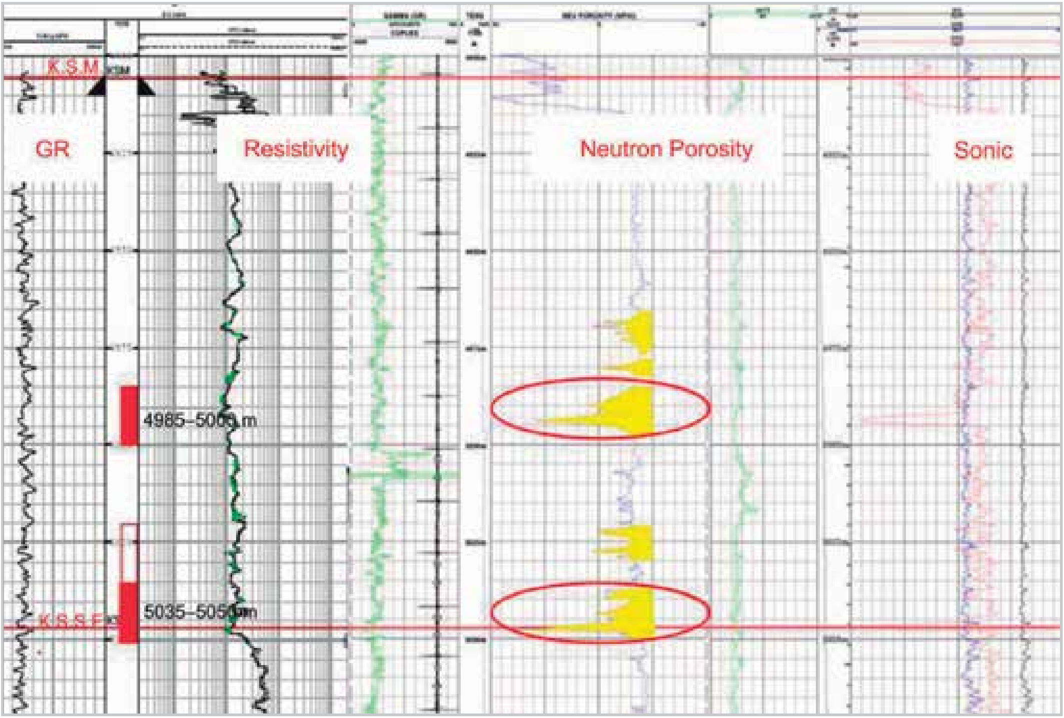

Fig. 3. Intervals within Well A.

Table 1. PLT results Well A.

Zones (m)	Water (STB/D)	Oil (STB/D)	Gas (Mscf/D)
Inflow 1 (4985 to 5000)	79.33	503.44	629.19
Inflow 2 (5035 to 5050)	238.8	263.17	334.11
Total	318.13	766.62	963.3

By comparing the flowing and static temperature curves, a higher temperature within the flowing profile was obtained, which indicated an ascendant preferential flow path, or channel, behind the production liner from the bottom of the well, **Fig. 4**.

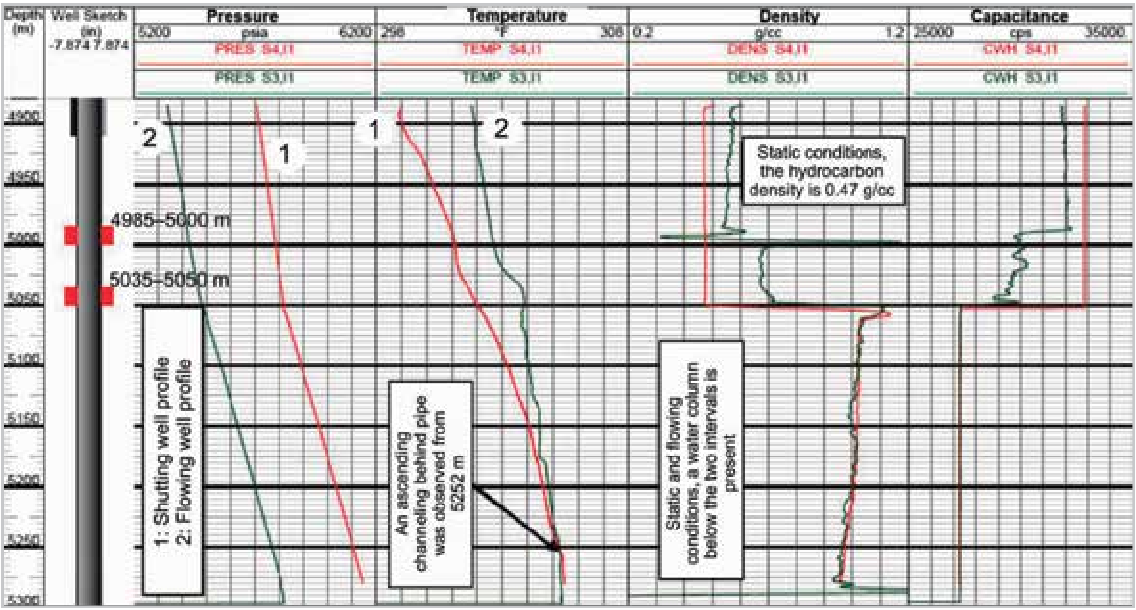

Fig. 4. Comparison of static and flowing curves.

After three years of producing at the same choking condition of 7/8 in., the water cut of Well A was increased from 1.0 to 80.0% within two months, **Fig. 5**.

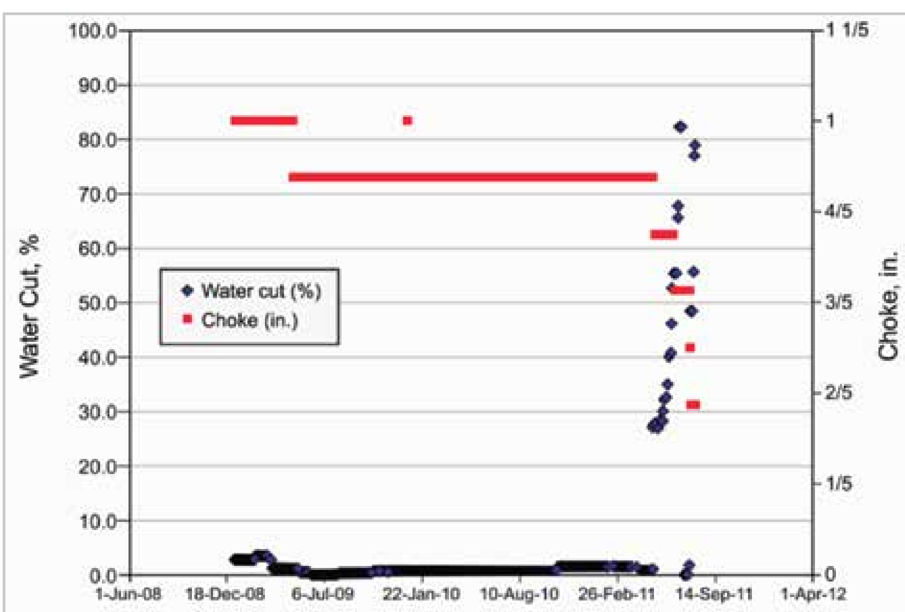

Fig. 5. Water cut and choke before treatment.

In some cases, an abrupt eruption of water into the well indicates a possible mechanical problem.

In addition to the PLT analysis, the cement well log was evaluated to confirm the presence of a channel behind the pipe observed within the production log. The survey was recorded within the 5-in. production liner of the deviated Well A. Generally, it exhibited poor bonding throughout the entire section. The average amplitude was approximately 60 mV. It is known that using only amplitude can yield a conservative cement evaluation; however, in this particular case, the PLT, cement bond log (CBL), and production history confirmed the presence of a channel behind the pipe, **Fig. 6**.

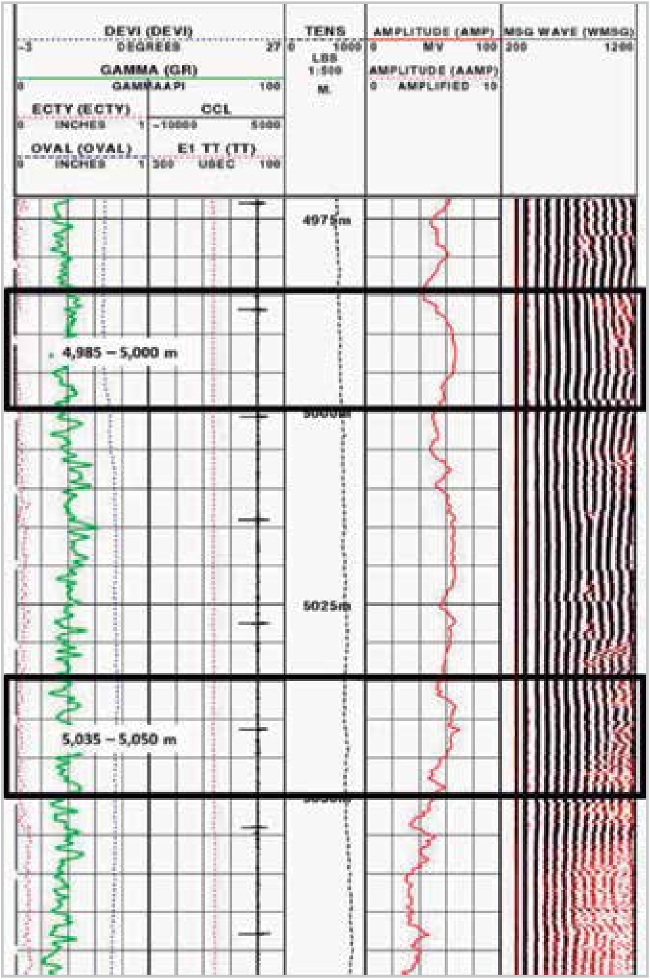

Fig. 6. CBL.

Because the channeling was diagnosed, the ultrafine cement was selected to repair the casing channeling. The treatment was pumped within two stages using a low volume of cement because there was no intention of completely isolating the intervals, considering that the zone produces by natural fractures.

For the treatment during every stage, 13 m^3 of an aromatic solvent was pumped as a preflush, followed by 3 m^3 during the first stage and 4 m^3 during the second stage of ultrafine cement with oil-based fluid. The displacement was 30 m^3 of diesel during every stage; the average rate and pressure were 3 bbl/min and 2,000 psi. After the pumping of every stage, the well was shut in for 24 hr. **Fig. 7**, illustrates the pumping parameters for the second stage.

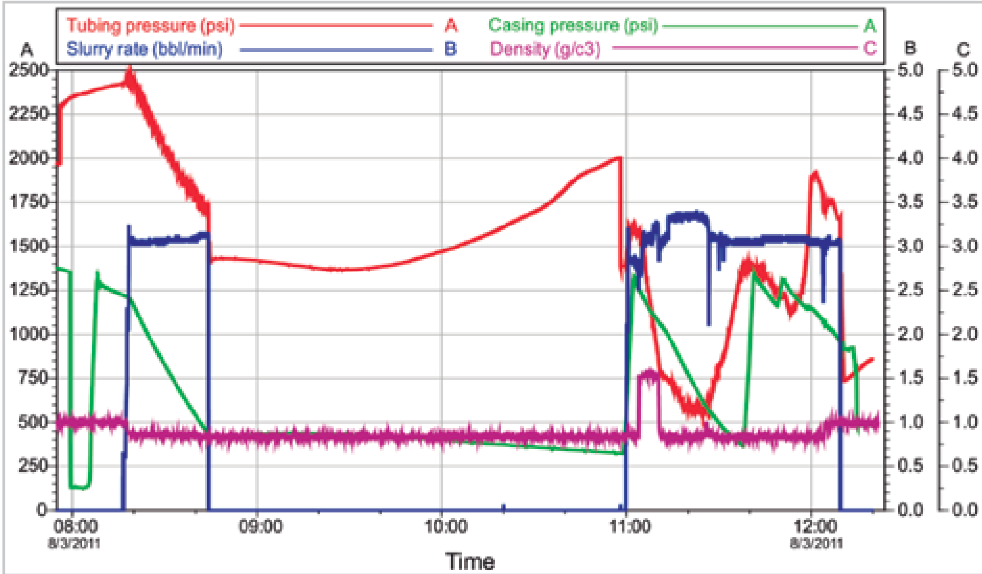

Fig 7. Case 1 pumping parameters.

Case history 2: natural water coning (Well B)

Case history well 2 is the highest cumulative producer well within the Sen field. During its production life, a progressive increase to water production was evident, and, eventually, the water broke through into the perforated section, replacing part of the hydrocarbon production. Well B is located between the moderately deep wells within the structure. The water/oil contact (WOC) is 4470 m, **Fig. 8**. Considering that Well B is a vertical well with a perforated zone at 4430 to 4465 m, the high water cut was the most significant problem during the treatment.

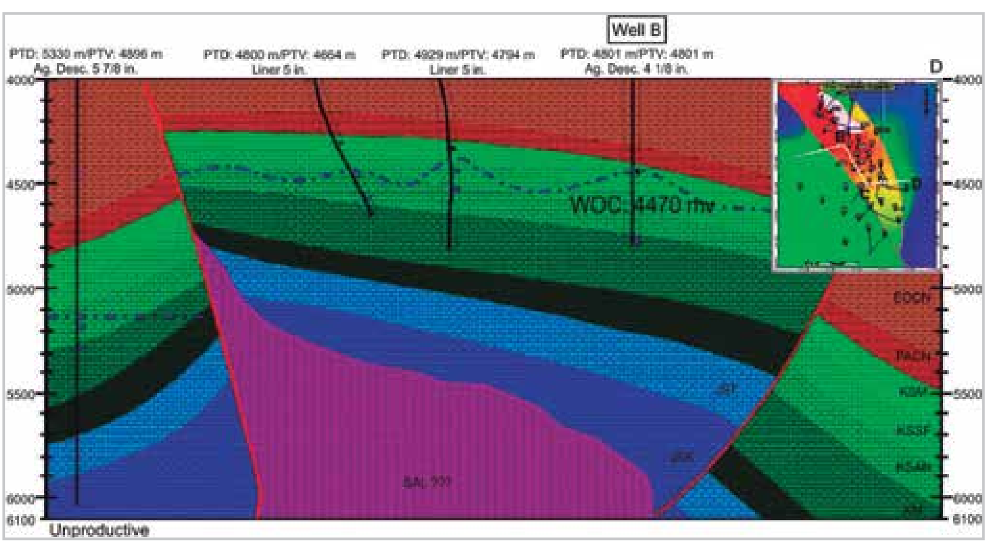

Fig. 8. Structural section case 2.

A PLT performed in April of 2013 exhibited a fluid column density of approximately 1.05 g/cc from the downhole section at 4462 m, corresponding to density and capacitance readings of 100% formation brine. From 4462 to 4456 m, the capacitance values increased, and the temperature decreased, indicating the entry of a water-oil mixture. Finally, from 4456 to 4435 m, a further increase in capacitance and decrease in density to 0.85 g/cc suggested the entrance of a water-oil mixture richer in oil.

Within this scenario, the water control was executed into two separate phases. **Table 2** shows the pumping parameters. During two stages at the end of the displacement, the pressure increased, corresponding to the ultrafine cement entering and reacting with the water formation. After deployment of the treatment, the well was shut in for 24 hr.

Table 2. Treatment summary: Well B.

Systems	Stage 1			Stage 2		
	Volume (m^3)	Rate (bbl/min)	Treating Pressure (psi)	Volume (m^3)	Rate (bbl/min)	Treating Pressure (psi)
Relative permeability modifier (RPM)	45	3	1100	—	—	—
Aromatic solvent (injectivity test)	24	3	1100	—	—	—
Aromatic solvent (preflush)	10	3	1100	10	2	2000
Ultrafine cement within oil-based fluid	10	3	1100	10	2	2000
Diesel (displacement)	27	3	2300	15	2	6000
Well shut-in	24 hr			24 hr		

Case history 3: channeling through higher permeability, (Well C)

Well C was perforated within the KSAN formation through three intervals at 4872 to 4885 m, 4897 to 4904 m, and 4943 to 4955 m. During December of 2012, a PLT was performed, indicating that the upper interval contributed to the entire production, and the two lower intervals did not contribute any fluids. According to the PLT, beneath 4872 to 4885 m, a gradient of water combined with a gas/oil gradient was present.

During February of 2013, an injectivity test was pumped using fluid tracing with radioactive tracers. Afterward, a memory based gamma ray casing/casing collar locator (GR/CCL) type log was run, demonstrating the preferential path to admission fluids into the upper interval, **Fig. 9**.

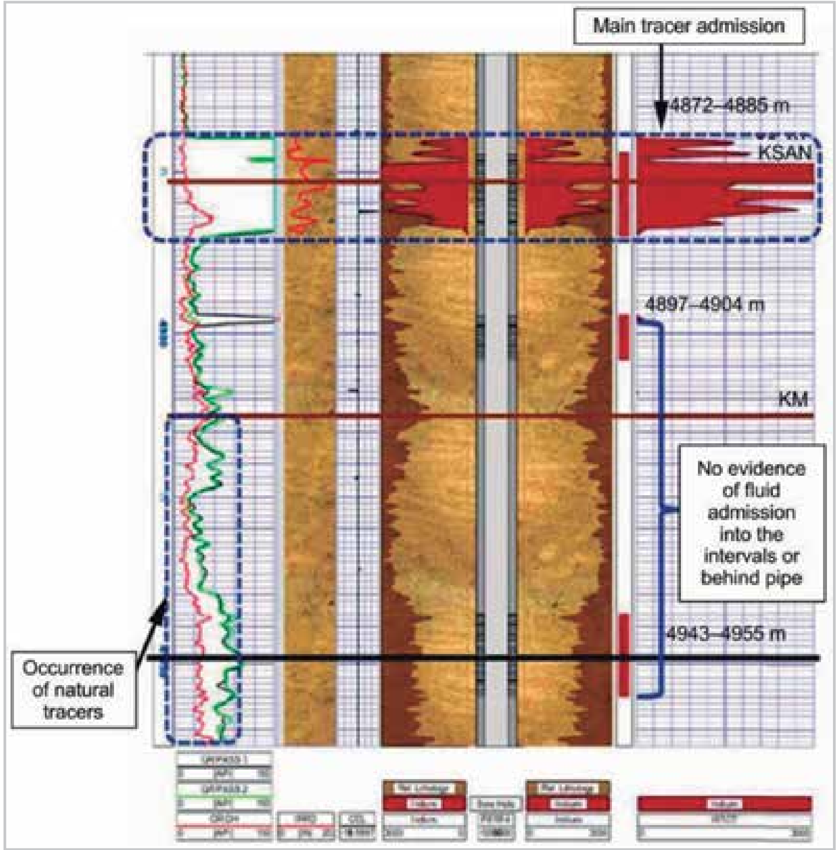

Fig. 9. Traced injectivity test: case history 3.

Conversely, the CBL demonstrated that the cement job was good—regular throughout the interest zones, and a channel behind the pipe was discarded. The tracer log, PLT, CBL, and production behavior indicated a sudden increase to the water-oil ratio during a short period of time from 2.0 to 37.0%, and then to 100% of water cut within at least a month. The conformance job using ultrafine cement in oil-based fluid was selected to specifically treat the upper interval, with the final objective to isolate the intervals and evaluate an additional zone.

Lastly, the openhole log analysis was considered to determine the petrophysical properties throughout the intervals, resulting in permeability contrasts along the three intervals, **Table 3**.

Table 3. Petrophysical properties Well C.

Intervals (m)	Height (m)	Effective Porosity (Fraction)	Vshale (Fraction)	Water Saturation (Fraction)	Permeability (mD)
4872 to 4885	13	0.046	0.27	0.27	11.03
4897 to 4904	7	0.028	0.32	0.32	3.3
4943 to 4955	12	0.038	0.34	0.34	8.82

In February, 2013, the water control job was executed through the three intervals. During pumping, the pressure was low, and, just when the cement was displaced into the perforations, the pressure increased to 500 psi. **Fig. 10** illustrates the pumping summary.

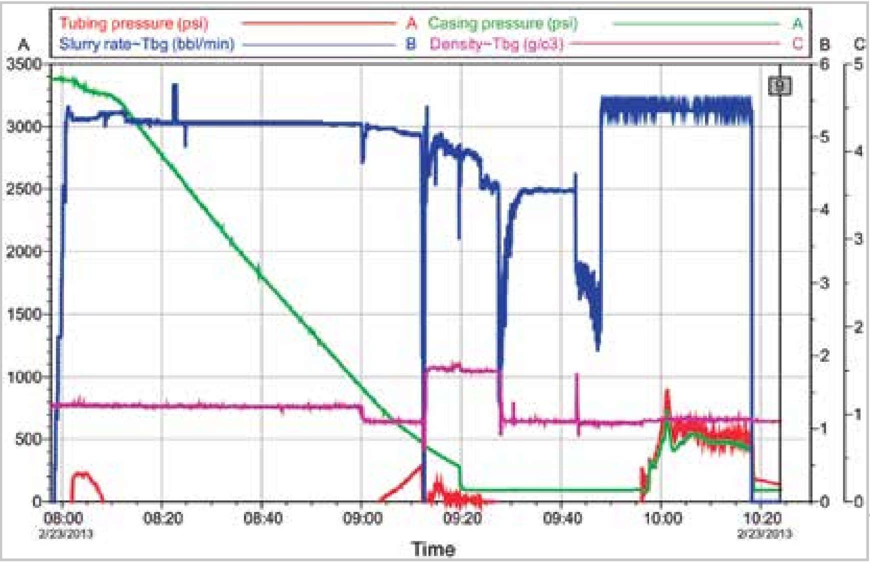

Fig. 10. Pumping stages: case history 3.

Production results

The water cut reduction after the conformance treatment was significant in Well A. As illustrated in **Fig. 11**, after approximately 21 months, the ultrafine cement job was performed, and the water production remained very low.

Before the job, the oil production was 500 B/D with 82.21% of water cut, flowing with a 5/8-in. choke. After pumping ultrafine cement, the stabilized oil production resulted in 2579 B/D with water cut of 2.15% and flowing with a 7/8-in. choke.

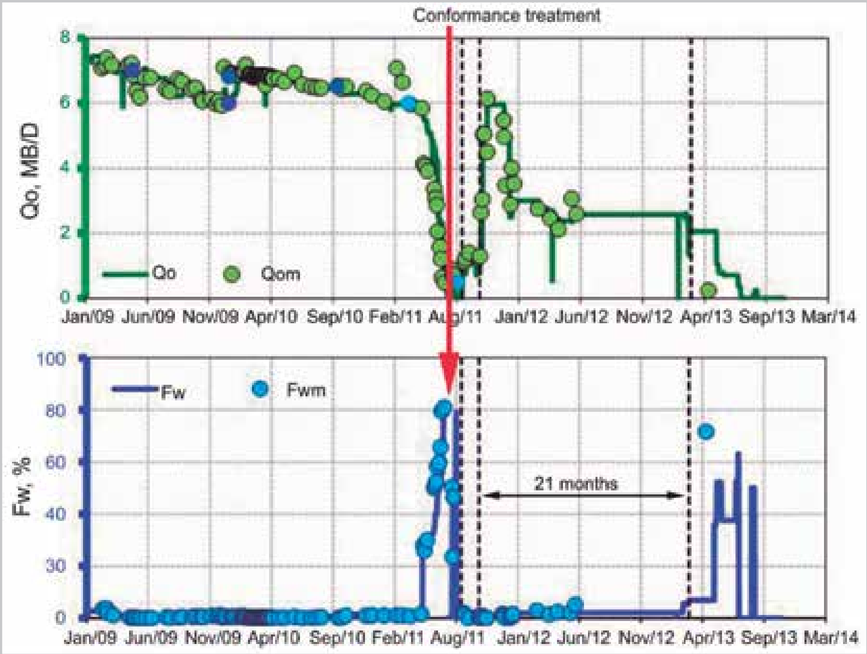

Fig. 11. Production history before and after conformance treatment Well A.

For Well B, before the conformance job, oil production was 99 B/D, with a 78% water cut naturally flowing with a 16/64-in. choke. After pumping the treatment, oil production increased to 252 BOPD, with a 59% water cut by the same choke. It is important to emphasize that this particular job was executed when the WOC existed 5 m below the perforations. As illustrated in **Fig. 12**, the water cut progressively increased from June of 2012 until May of 2013 when the job was performed. Within this scenario, it is feasible to apply this technique using ultrafine cement in oil-based fluid; however, because of the water breakthrough into the perforations, combining with a permanent seal below the perforations is advised before pumping the selective system.

Notice that, even post-treatment, the water cut increased to 80% within a short period of time.

In Well C, at the moment of intervention, water cut was 100%. In this case, the cement job was performed to abandon the intervals and add a new zone. Notice that this well presented a channeling through higher permeability and only the upper interval admitted the injected fluid. Therefore, the objective was to isolate the zone, implementing a conformance job, before placing a mechanical plug, as well as help prevent early water influx into the new zones to perforate. Finally, the new interval at 4795 to 4808 m was added, flowing four months before water was present. **Fig. 13** illustrates the production history of well C.

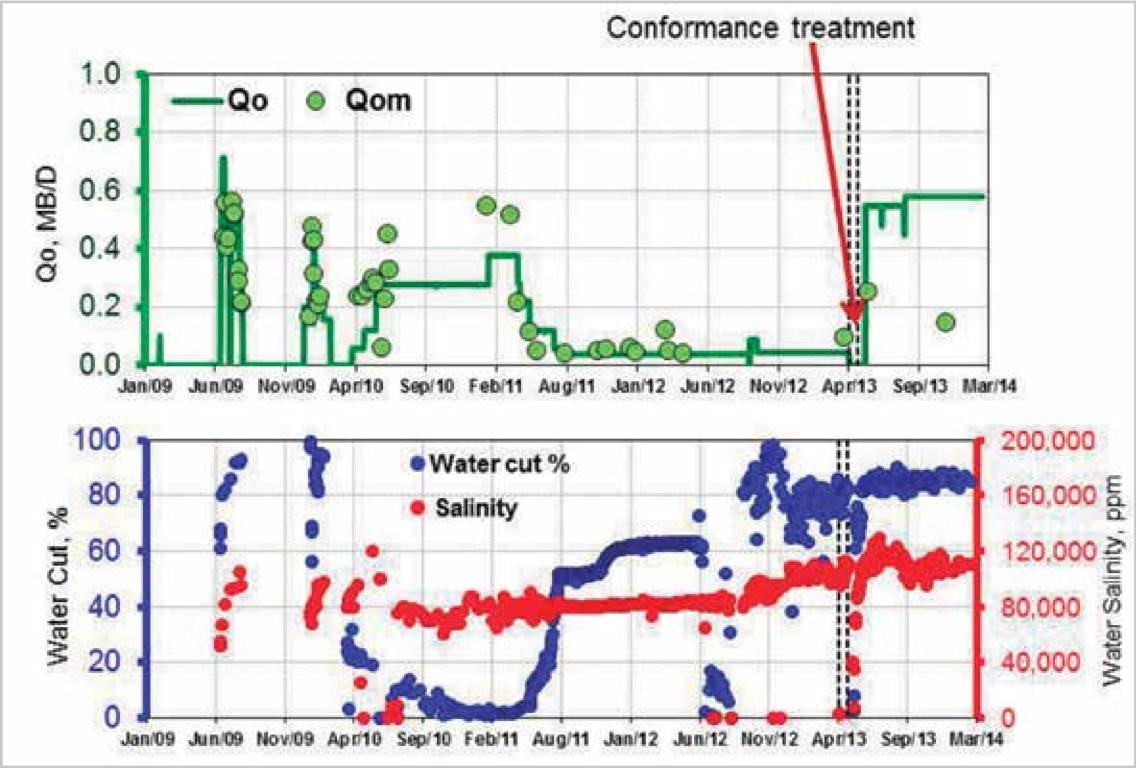

Fig. 12. Production history before and after ultrafine cement job in Well B.

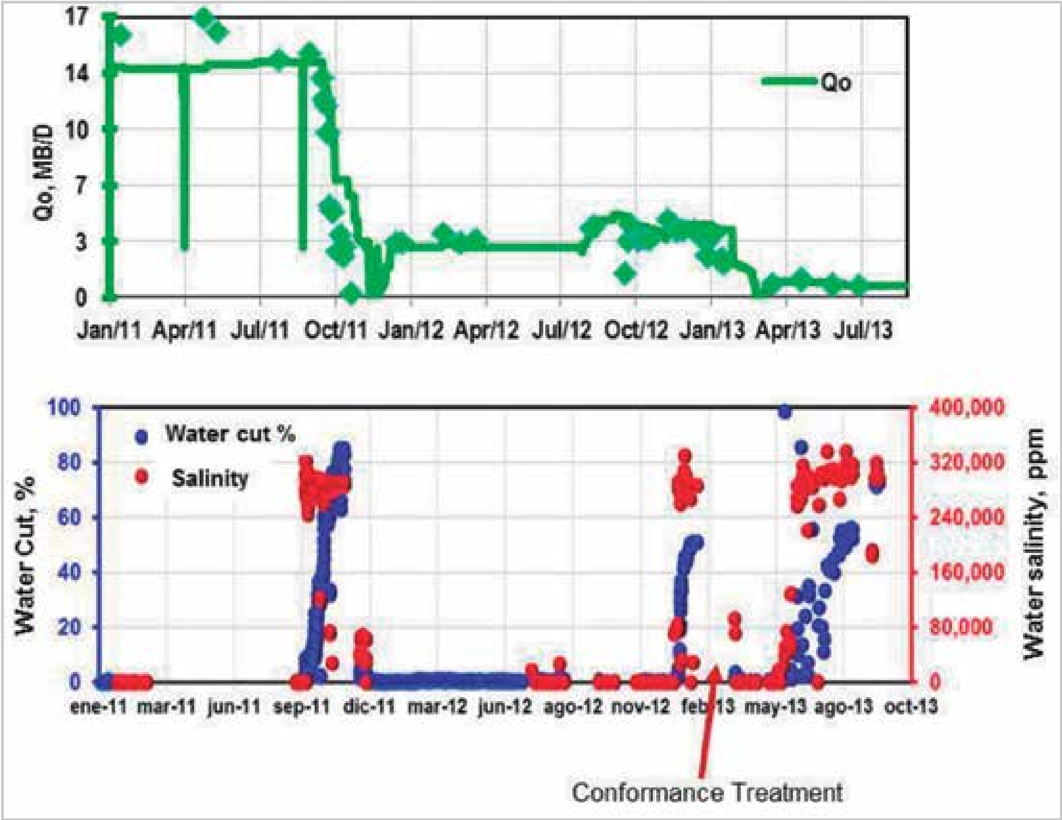

Fig. 13. Production history before and after job in Well C.

Conclusions

The appropriate application of conformance technique using ultrafine cement in oil-based fluid resulted in the reduction of water production in different scenarios within naturally fractured carbonate reservoirs.

To identify the problem source, a good diagnosis using the best data possible, such as production logs, openhole logs, CBLs, and production history, are key to minimizing the risk factor present during such treatments for these particular reservoirs.

In some cases, the treatment should be performed during two separate stages for optimal results.

For the final designs, new laboratory quality control based on optimal cement rheology implemented during past projects was considered.

Although the water control job did not result in increased production, application of the technologies can often help improve profitability by helping achieve a longer productive well life, evaluate new zones, reduce lifting costs, and reduce environmental concerns and costs.

Nomenclature

mV	= Millivolts
MMscf	= Million standard cubic feet
MB/D	= thousand Barrels per day
BOPD	= Barrels of oil per day
CBL	= Cement bond log
PLT	= Production log testppm = Parts per million
Qo	= Oil rate
Qom	= Monthly oil rate

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A partir de febrero de 1989 laboró en el Distrito Comalcalco en el Departamento de Ingeniería de Yacimientos; en febrero de 1994 colaboró en el Equipo Interdisciplinario Sen de la Superintendencia de Producción del mismo Distrito; en julio de 1997 fue asignado al área de Ingeniería de Yacimientos en el Activo de Producción Luna; de diciembre de 2004 a julio de 2008 fue Líder del Proyecto Integral Delta del Grijalva en la Coordinación de Diseño de Explotación del Activo Integral Samaria Luna y desde agosto de 2008 a la fecha, se desempeña como Coordinador de Diseño de Explotación del mismo Activo.

Ha efectuado varios estudios de comportamiento primario de los campos petroleros de la Región Sur, de simulación numérica de yacimientos y de caracterización de fluidos. De mayo del 2000 a octubre del 2001 fue comisionado a la Ciudad de Denver, Colorado, para supervisar el estudio integral del Campo Sen.

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