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A Successful Experience For Fiber Optic And Water Shut Off On Horizontal Wells With Slotted Liner Completion In An Extra Heavy Oil Field

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Abstract:

Identifying the water producing section of a horizontal well completed with a slotted liner in Extra Heavy Oil (EHO) proves by itself to be a challenge. Being able to isolate that same interval and selectively injecting a water shut off treatment is even more challenging. To properly isolate the selected section, the annulars (open hole / slotted liner) above and below must be sealed; those annular may or may not be filled with formation sand.

This paper describes the water shut off experience in the Sincor Field in an EHO environment. Initially, the water producing interval was identified through the use of temperature measurements performed with a fiber optic. Then the zone to be treated was isolated using cement rings placed in the annulus, combined with the use of cement retainers. Following the isolation of the zone, a gel solution that polymerizes in situ followed by a tail slurry of micro-matrix cement were selectively injected. The idea behind the treatment is to create an impermeable barrier to the unwanted water production coming from the end of the well. The well treated had an initial water cut of 85%, and after the treatment the water cut was decreased to almost zero and the oil production boosted up by a 250%, compared to hydrated production period. Additionally, the final well productivity index (PI) indicates that the treatment effectively treated only the selected section.

In horizontal wells and EHO environment, the fiber optic tool proved to be a simple and reliable technology to assess the water production zone along the drain. An associated water shut off operation using cement and gel may then be implemented to reduce the water cut and to increase significantly the oil production rate.

Introduction

The Zuata field operated by SINCOR, a consortium of TOTAL, PDVSA and STATOIL, is one of the four strategic associations in the Orinoco Belt of Venezuela. The location of the field is shown in Fig. 1. Laying in unconsolidated sand at depths between 300 m and 500 m, the reservoir fluid is extra heavy oil with gravity ranging from 7.5° to 9° API and viscosities between 1800 cp and 3500 cp at reservoir conditions.

The oil is produced by natural depletion from horizontal wells with 1400 m drain length. The reservoir fluid is mixed with a diluent in the wellbore or at the wellhead ; the diluted crude oil is then pumped to a processing center for water and gas removal. The stabilized oil is transported by pipeline to an Upgrader for further processing to produce a low sulfur high quality 32° API synthetic crude named the Zuata Sweet. The produced water is injected into the Lower Oficina aquifer.

Well production history

As one of the first producers, the well IB03 was drilled in 1999 in the south-western part of SINCOR area. Drilled in a massive 25 m thick sand to 2086 m (TMD), the horizontal section is 1350 m long and was completed with a 7” liner. Slot size is 20 (width 0.02 inch). Brought on production on December 17th 2000, the well produced a maximum of 2400 stb/d with a productivity index of 12 stb/d/psi approximately. After two months of production, water brokethrough. The oil production level dropped drastically to 700 stb/d of EHO with an associated water production of 1100 stb/d. The water cut rose rapidly to 60% then 80% (Fig. 2). The well was shut-in from October 2001 to September 2002.

Fiber optic to detect water production zone

In order to assess the water entry point, a fiber optic cable was installed in the horizontal section of the well in June 2001. The objective was to measure accurately the temperature profile along the horizontal section and to identify a possible increase of temperature due to the water entry [1][2]. The temperature is permanently measured every meter and averaged over ten minutes period.

In the area, the aquifer zone is located 21 m below the well. It means that the water is expected to be up to 0.6°C hotter that the oil produced at the drain depth.

In the well IB03, the temperature profile yielded a significant increase of 0.2°C around 1710 m MD (measured depth). This interpretation identifies a probable water entry point around 1710 m MD with the water cooled down when going up through the oil zone (Fig. 3 and 4) . This result is consistent with the fact this point is the deepest TVD point of the well. Moreover the horizontal drain is diving below a shale layer just before the water entry point (Fig. 5). As the water entry interval is short and as the water/oil mobility ratio is high (around 2000), the hypothesis that the water is produced by fingering from the underlying aquifer is highly probable.
Following a detailed geological interpretation, it was proposed to treat the well by isolating the lower section where the water entered. Once the water shut off treatment is in place, the shale layer crossed by the well should protect the upper part of the drain from water.

The well was reproduced during two weeks in September 2002 to assess the status before the curative operation. At this stage, the well produced at a water cut of 85% with 400 stb/d of EHO and 2280 stb/d of water.

Water shut off operation

After the clear identification of the water entry point in the well IB03, it was proposed to perform a water shut off operation in order to isolate the portion of liner producing water and located below the shale layer. As the water entry point was located at 1710 m MD, i.e. toward the toe of the drain, it was also proposed to abandon the bottom part of the drain.

A first attempt to perform the operation with a coil tubing unit was unsuccessful due to obstruction problems and metal straps encountered in the well. It was then agreed to use a rig and a 3-1/2" drill pipe.

The cleaning assembly used included a 6-1/8" bit, 5" Junk Basket (for 7" liner), a Scraper, and a 7" Junk basket (for 9-5/8" Casing). This assembly was run through the previous lock up point (1236 m measured depth) without any problems.

Due to the fact that the well remained without treatment for 2 months after the first attempt, a solvent to clean the slots of the 7 " liner was used. A 40 barrels batch was pumped in the interval of the first cement ring and another 90 barrels were pumped in front of the interval to be treated with the gel and cement.

The SIP (Selective Injection Packer) tool assembly was then prepared and run in hole to the depth of the first cement ring, checking the seal of the rubber cups in all the blank liners. The first cement ring was successfully placed in the interval between 1807 m – 1846 m MD. The bottom hole assembly was pulled out and it showed cement traces only between the two cups, indicating that the placement had been successful.

Since cement traces could have been left inside the 7" liner after pulling out the BHA, it was programmed to set the cement retainer before placing the other two cement rings. The cement retainer was set without problems at 1834 m MD; only traces of cement were observed in running assembly. The running assembly was pulled out and the SIP tool was again prepared to set cement rings 2 and 3.

Cement ring # 2 was placed in the interval 1622 m – 1651 m MD. The SIP tool was again retrieved and redressed to set cement ring number # 3. This cement ring was placed in the interval 1554 m – 1583 m MD. The SIP tool was pulled out and the running tool to set the cement retainers was run in the drain.

The second cement retainer, isolating the inside of the 7" liner at the deeper end of the treatment interval, was set at 1635 m MD. The running tool was pulled out and redressed to set the third and final cement retainer at 1581 m MD, therefore completing the isolation (both inside the 7" liner - through the cement retainer - and the outside the 7" liner - through the cement rings) of the treatment interval.

Two hundred barrels of the gelling polymer followed by 20 barrels of micromatrix cement were prepared and pumped while remaining inside the third cement retainer with the stinger. Following this procedure, all the treatment of the interval was carried as per plan (Fig. 6).

The well was recompleted with a PCP pump and a fiber optic cable for future monitoring was set. The pump was run in hole several hours after the estimated gelling time for the polymer and setting time for the micromatrix cement. Therefore, the treatment appears to have been placed according to plan. If the treatment had been forced into the formation and traveled back into the slotted liner, the gel and cement would have impeded the pump from reaching the final depth.

Production results

After the water shut off operation and the installation of the new completion that ended in December 2002, the well was put in production in March 2003. The unplanned long delay allowed a better gelling time. When the well restarted, the water cut dropped within two weeks from 55% to less than 5% in a clean-up phase. Then the water cut stabilized at 2-3% with a EHO production rate of 1000 stb/d (Table 1).
Following the PI decline, the EHO production rate stabilized at 800 stb/d with a controlled pressure drawdown on the well to avoid gas production (Fig. 7).

The well was shut-in during one week in May 2003. The pressure build-up interpretation was compared with the initial one performed at an early stage in the life of the well. The permeability was in the same range: 19 D after the water shut off operation vs 17 D initially (Table 2, Fig. 8 and 9).
From this result, it can be inferred that the injected chemical did not damage the reservoir formation around the drain.
The initial PI of the well was 12.4 stb/d/psi. According to the well decline in the area and to the reduction of net sand, the expected PI after the water shut off was 3.4 stb/d/psi. The observed PI after the water shut off was 2.8 stb/d/psi.

This result indicates that the whole zone located in the drain before the isolated zone i.e. before 1554 m measured depth is contributing.

The late production data indicates that after a long shut-in in June and July 2003, the water brokethrough again in the well IB03. The water-cut has increased steadily from 10% in July 2003 to 16% in October 2003 (Fig. 10). The fiber optic tool gives indication that the water in coming from the end of the current drain. The water may be passing behind the water shut off treatment to reach the producing interval. In October 2003, the well is producing around 600 stb/d of EHO i.e. still 50% more than the EHO rate before the water shut off operation.

From March 2003 to October 2003, the well has produced an EHO cumulative of 120.000 stb in 152 days. Assuming that a EHO production of 400 stb/d without the water shut off operation, the increment EHO production related to the water shut off is 60.000 stb. With an associated cost of $950,000, the operation has been paid by the incremental production.

Results analysis
The costs of this operation, $950,000 , are as follows:
- $ 80,000 for the fiber optic equipment
- $ 360,000 for the first attempt for the coil tubing unit
- $ 510,000 for the second attempt with the rig.

The operational cost of this first pilot test has been high, particularly because of the unexpected borehole conditions that led to the first operational failure with the coil tubing unit in September 2002. However, without optimizing the operation or chemicals, forcing the chemical treatment into an equal length interval, and only using the rig, the entire operation could be performed for approximately $ 560,000. This would include the costs of pulling out and rerunning the completion.

Based on the acquired knowledge, both the operational and the chemical costs could be reduced. Similar polymers with lower costs (other gelling agents with higher viscosities than the one used), could be pilot tested to determine their efficiency.
From an operational point of view, the timing and equipment used could also be optimized. With the current know-how the water shut off operation itself could be performed in 5-6 days.
As this operation was the first pilot test, it was considered that having only one provider of chemicals, tools, and services was the best strategy to follow.
It is important to point out that each particular water shut off case presents different challenges, which may require the use of different technologies. As this is the first water shut off operation in Sincor, a learning curve and pilot testing of different technologies (other blocking agents, relative permeability modifiers) must be established to determine the operational and economic success.

Well characteristics
From the experience in the well IB03, the water production zone has to be considered according to different guidelines in order to properly design the water shut off:

1- The location of the water production zone within the drain:
If the water entry point is closed to the toe, it can be proposed to abandoned the bottom part of the drain (i.e the part of the drain located after the water entry point), as it has been done in the case of the well IB03. However for a long horizontal drain, the implementation of the water shut off treatment may be operationally more difficult. A coil tubing would speed up the operation provided it can reach TD.
If the water entry point is close to the heel, the operation is easier to perform. However, in this configuration, the production of the bottom part of the drain is mandatory to ensure economical success. Therefore the section of liner in front of the water production zone has to be clean out.
This type of operation has not attempted yet in Sincor but is looked at as a next stage in the water shut off in horizontal well in EHO environment.

2- The presence of shale sections in the drain:
The presence of shale sections related to laterally extended barriers in an horizontal drain is supposed to improve the water shut off operation if the cement and gel treatment is set beside this shale section. The water will take more time to find a new path toward the open part of the drain.

3- The drain trajectory:
If the trajectory of the horizontal drain is slightly inclined, it may increase the tortuosity of the water path toward the open part of the drain and therefore it may delay the water breakthrough that is likely to occurs sooner or later after the water shut off operation.

Recommendations
Locating the water entry point(s) is a key element for the success of any water shut off operation. A proper detection log or monitoring is mandatory. The operation will fail (ie. the well water cut production is not reduced) even if the treatment is perfectly designed but pumped at the wrong place.

The fiber optic technology offers a good resolution to identify the water production zone in a horizontal drain if the water comes from an underlying aquifer. Above 1°C difference between the oil and the water i.e. for an aquifer located at least 15 m below the horizontal drain, the tool should detect a temperature increase related to the water occurrence.

It may be more difficult to use in case of a lateral aquifer where the temperature difference between the oil and the water could be too low to be detected.

After a positive economic evaluation in the first water shut off experience in Sincor field, the use of this technique (permeability blocking agents) will be further studied to optimize costs. Most of the cost reduction possibility lies in the placing method and the chemicals used.

The placing method, with the open hole / slotted liner completion used in Sincor wells, could be tested without the use of the annular cement rings (considering there is no annulus between the 7" liner and the open hole). This way, the placement of the treatment would rely only on the viscosity / mobility difference between the water producing zone and the oil producing zone.

The chemical cost of the operation could also be significantly reduced. Through testing of the permeability blocking gelling agents in the market, a better cost option could be determined

As an alternative, it is recommended to evaluate the use of RPM, relative permeability modifiers [3][4]. Typically, these chemical agents have been tested in vertical wells and have been placed through direct bull heading. However, it is not certain that this approach could be used for horizontal drains. Also, it is important to point out that this type of treatment is of a temporary nature (requires pumping the RPM periodically to maintain reduced water cut).

Conclusion

The fiber optic can be extensively used in EHO environment when tracking water production. The technology allows to identify clearly the water production zone in an horizontal drain if the water comes from an underlying aquifer.

In the Orinoco belt, there is a potential for an extensive study on the water shut off problem according to various well trajectory (drain going up or down), well geology (presence or not of shale section in the drain), water entry point location (at the heel or at the toe of the drain).

Each water shut off case must be evaluated on an individual basis to determine the cost / benefit potential and establish the proper treatment technique according the well characteristics.

Acknowledgement

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Reference

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Data	Initial status (before water breakthrough)	Status before water shut-off	After water shut-off Prognosis	After water shut-off Observed
Net sand (ft)	3577	3577	1967	1967
Net pay (ft)	2210	2210	1017	1017
PI (stb/d/psi)	12.4	4.7	3.4*	2.8
Oil potential (stb/d)	2400	**400**	**1070**	**910****
Water rate (stb/d)	40	2280	20	30
Water-cut (%)	1.6	85	2	3
Increment (stb/d)			**+670**	**+510**

* Including Well Decline (0.6) and net pay ratio
** Average production rate March – June 2003

Table 1: Production data – well IB03

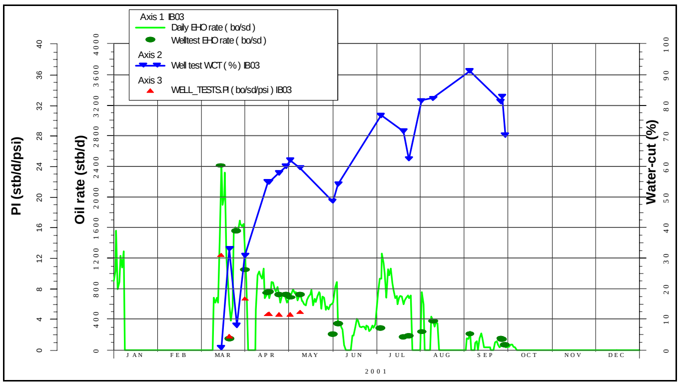

Fig. 2: Well IB03 production history in 2001

After WSO BU	
Production Parameters @ Shut-in	
Rate (Blpd)	1000
Cum. Prod. (Bbls)	44000
Water Cut (%)	1.6
GOR (cf/Bbl)	83
BU Interpretation Parameters	
C (Stb/psi)	0.04
Skin – Damage	0.15
Press. Drop Skin (Psia)	10
Well position to top (Feet)	15
Net pay (Feet)	50
Length Effective (Feet)	1967
K (Darcy)	19
K_V / K_H	0.1
Matched Pi @ SRO Gauge Depth	567.3
Measured Pi SRO Gauge Depth	567.7

Table 2:
Pressure build-up analysis in 2003, after the water shut off

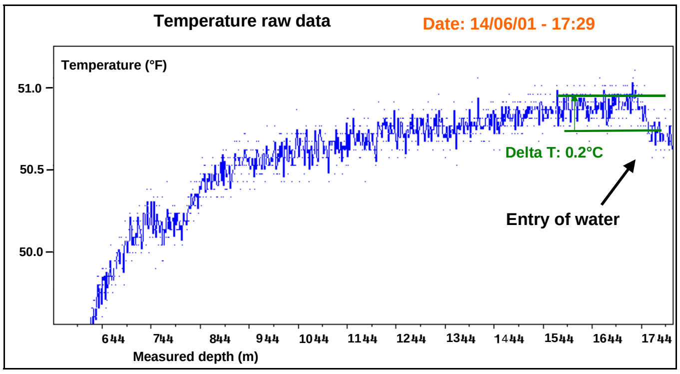

Fig. 3: Temperature profile along the drain IB03

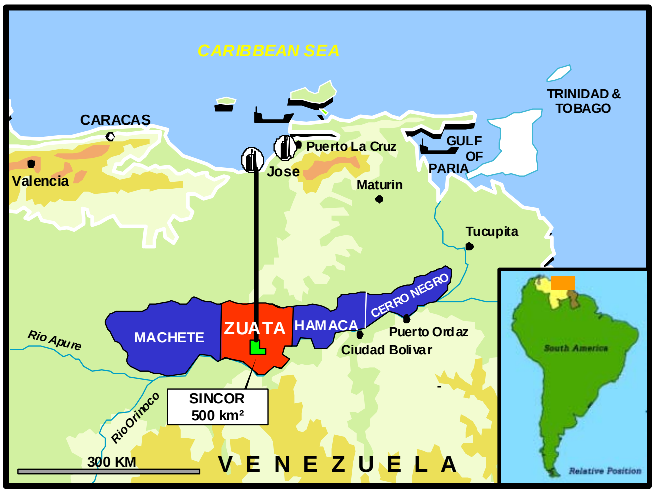

Fig. 1: Map showing location of the Zuata Field

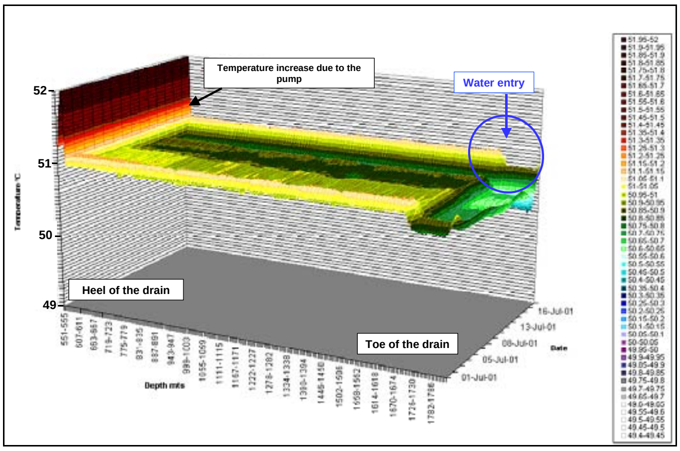

Fig. 4: Temperature profile from fiber optic in 3D

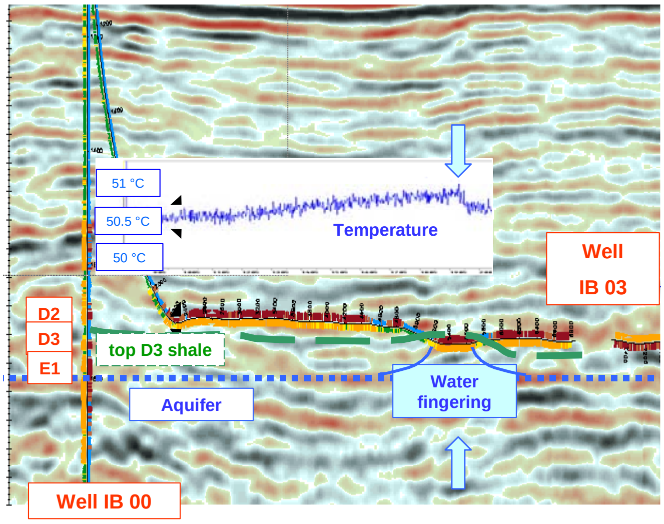

Fig. 5: Geological interpretation of the drain IB03

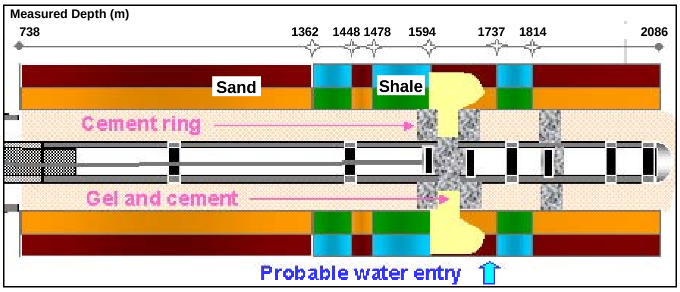

Fig. 6: Water shut off setting in the drain IB03

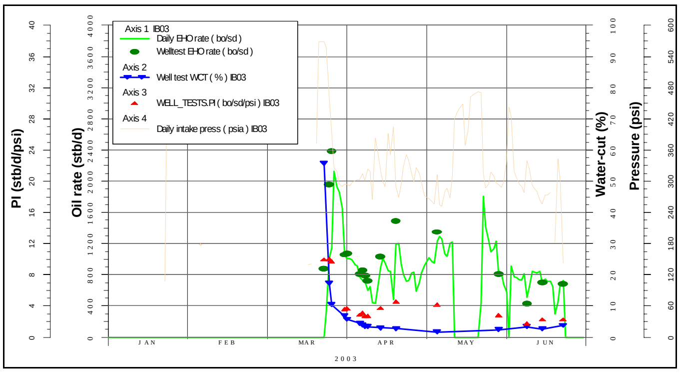

Fig. 7: Well IB03 production history just after the water-off

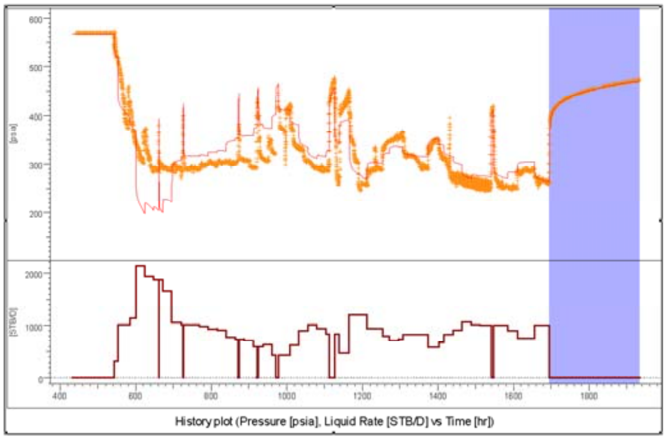

Fig. 8: Well IB03 pressure history match in 2003

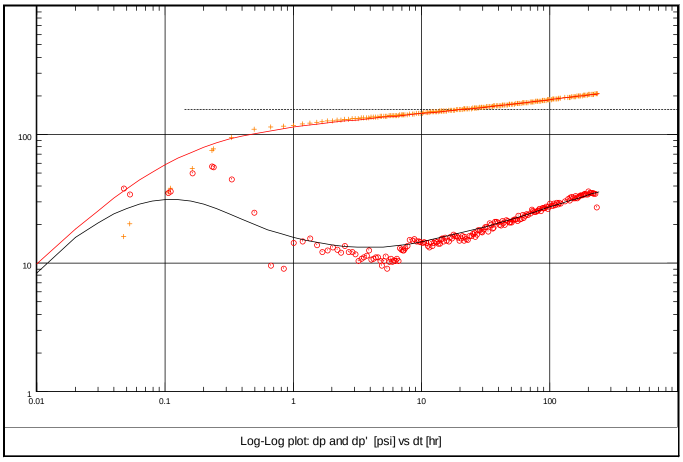

Fig. 9: Pressure build-up analysis in 2003 after the water shut off

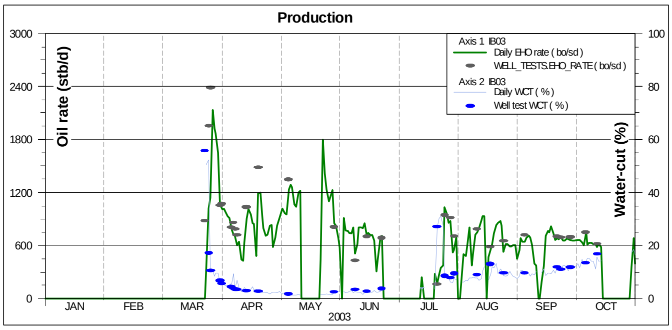

Fig. 10: Well IB03 production history in 2003