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Improving Recovery from Oil Sandstone Reservoir by Re-inject of Produced Water by Using Eclipse_E300 Software

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Abstract Re-injected produced water into sandstone reservoir at the initial stage is to maintain reservoir pressure, replace produced oil, and provide for the recovery of oil by water displacement. Water injection essentially increases the rate of oil field development and in many cases permits increased oil recovery. This paper demonstrates a successful simulation case study based on a field data of project. The objective of this study is to improve recovery from oil sandstone reservoir by four re-inject wells of produced water within ten years for twenty-six oil production wells. In order to do that, first, the simulation 3-D model built by using advanced reservoir simulation software (Schlumberger Eclipse_E100) [1]. Second, select the best zone for water displacement. Third, select the best location for injector well. Fourth, determine the injector well depth. Fifth, make a sensitive of water injection rate to determine the optimum rate. Sixth, re-inject water produced with optimum rate.Results obtained in this research show that, the location of injection wells will influence the oil production rate and recoverable reserve. Time management also one of the most important factors which may influence the oil recovery. The right time to inject water is very important. Results of this study suggest that simultaneous re-inject of produced water will increase the recovery factors by up to 15 % of originally oil in place. This present study may hopeful be useful as reference of information for any operating company to establish the re-injection of produced water of field.

Keywords: Water Injection, Oil Recovery, Sandstone Reservoir, Produced Water, Eclipse 2009_E300.

تحسين الانتعاش النفطي من الخزان الحجر الرملي عن طريق اعادة حقن المياه المنتجة باستخدام برنامج Eclipse_E300.

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الملخص اعادة حقن المياه المنتجة في خزان الحجر الرملي في المرحلة الأولى هو الحفاظ على ضغط المكمن، واستبدالها بالنفط المنتج وتحسين انتعاش النفط عن طريق إزاحة الماء. حقن المياه يزيد أساسا من معدل تطوير حقول النفط وفي كثير يسمح بزيادة انتعاش النفط. تظهر هذه الورقة دراسة حالة محاكاة ناجحة مستنذة على بيانات مشروع حقلية. الهدف من هذه الدراسة هو تحسين الانتعاش النفطي من الخزان الحجر الرملي وذلك بإعادة حقن المياه المنتجة بواسطة أربعة آبار حقن لمدة عشرة سنوات و ستة وعشرون بئر انتاج. من اجل القيام بذلك، أولا، بناء نموذج محاكاه نموذج 3 D-باستخدام برنامج المتطور ..[1] (Schlumberger Eclipse_E100) ثانيا، تحديد افضل منطقة لازاحة المياه. ثالثا،تحديد افضل موقع بئر الحقن. رابعا، تحديد عمق بئر الحقن. خامسا، إعادة حقن المياه المنتجة بمعدل مختلف لتحديد المعدل الامثل للحقن سادسا، اعادة حقن المياه المنتجة بمعدل افضل. أظهرت النتائج التي تم الحصول عليها في هذا البحث، ان موقع ابار الحقن يؤثر علي معدل انتاج النفط والاحتياطي القابل لاسترداد. إدارة الوقت أيضا واحده من اهم العوامل التي قد تؤثر علي استرداد النفط. اختيار الوقت المناسب لحقن المياه مهم جدا. وتشير نتائج هذه الدراسة الى ان اعادة حقن المياه المنتجة سوف تزيد من معامل الانتعاش بنسبة تصل الي 15% من النفط الاصلي. نامل ان تكون هذه الدراسة مفيده كمرجع للمعلومات لأي شركة خدمية لتعمل على إعادة حقن المياه المنتجة من الحقل .

الكلمات المفتاحية: حقن المياه، استرداد النفط، خزان الحجر الرملي، المياه المنتجة، برنامج.Eclipse_E300.

Introduction

Generally, improving recovery from oil sandstone reservoir on many oil production fields achieved by re-inject of produced water. Water injection is one of the key technology for oil reservoir exploitation. Being able to recycle production water allows producers to save water resources [2]. During the lifetime of the field, therefore, the level of the formation water aquifer underlying the oil-producing zone will rise until eventually it reaches the perforated zone of the producing well. This known as water breakthrough [3]. The field has since been an oil producer with the peak production of about 5200 BOPD that achieved in June 2009. The production managed from formation in depths ranging from 2300 ft to 3700 ft. The composing rock of the formation dominated by sandstones with some shale breaks. It considered necessary to document a strategic plan to develop further the field. Therefore, the present study of improving recovery from oil sandstone reservoir by re-inject of produced water conducted. The reservoir grid is made of 68 x 46 x 56 = 175168 cells. Only 11428 cells are active. The typical dimensions of a grid cell is DX = DY = 75 m, and DZ from 5 m to 25 m. Vertically, the grid split into 15th zones had better represent the stratigraphy of the reservoir. The zones part of the reservoir is modeled from 2 to 3 Layers.

Background of this Field

The production history data are available starting from mid-1996 to October 2010. After a well is drilled and production starts for a solution gas drive reservoir, the pressure drops in the vicinity of the well. The initially pressure drop is rapid as flow results from the low compressibility of the system above the bubble point. Pressure continues to decline and solution gas drive becomes effective as gas comes out of solution. Mobility of gas occurs and the reduced mobility to oil and resulting decreasing oil relative permeability further causes the pressure to decline and productivity to oil flow decrease. This field has produced since 1996 until October 2010 its 10.5 MMSTB from the original oil in place (OOIP).

Methodologies

Figure (1) is shows the methodologies workflow used in the present study.

- **Injector well zone:** To prepare the best zone for water injection, we must know the biggest OOIP. From figure (2), the biggest OOIP in 10th zone and has 11 existing wells. Therefore, we can conclude that the best sand for injection water it is in 10th zone.

- **Injector well location:** We decided to use some of the producing wells to be an injector wells after their performances are declining. This decision is taken also because of the economic reason. Figure (3) shows injection wells are; injector (I1), injector (I2), injector (I3), and injector (I4). Also, shows prodction wells are; producer (M1), producer (M10), producer (M22), producer (M20), producer (M25), producer (M15), producer (M27), producer (M14), producer (M18).

- **Injector well depth:** In water injection operations, there is a critical pressure (approximately 1 psi/ft of depth) that, if exceeded, permits the injecting water to expand openings along fractures or to create fractures. Consequently, an operational pressure gradient (PG) of 0.75 psi/ft of depth normally is allowed to provide a sufficient margin of safety to prevent pressure parting. In this field, the pressure gradient is 0.9 psi/ft of depth .We have depth for each Injector well, so we calculate the maximum fracture pressure (MFP) as shown in following Table (1).

- **Injector well rate:** After we know which zone we will Inject, and which wells will convert and how much the bottom hole pressure target for each Injector wells. Now, we start to inject water, but before that we must estimate the best rate of water for each well injector. To estimate the best rate we can inject, we will play in the rate of injection for each injector wells by 500 bbl/day, 700 bbl/day, 900 bbl/day and 1100 bbl/day.

- **Water injection scenarios:** After we have optimum the injection rate for each wells Injector, then we have scenario for water injection.

Result and Analysis

This scenario was using 13 wells consists of 9 producers wells and 4 injectors wells. Well pattern of this field in this a scenario is shown on the Figure (3). The injector (I1) was located at the external boundary of the reservoir in water zone to maintain the reservoir pressure. Other injector wells (I2, I3 and I4) were located in oil zone to move forward the oil to producer wells.

Injector (I1) set to 1100 stb/day. Injector (I2) set to 700 stb/day. Injector (I3) set to 500 stb/day. Injector (I4) set to 500 stb/day, as shown in the Figure (4). The rate of injector (I1) is used to maintain the pressure drop in the reservoir, while I2, I3 and I4 to drive the oil to producer wells and to prevent the gas expansion. Injector (I1) is open on November 2010 to maintain the reservoir pressure from aquifer. At the same month, we open the injector (I2) in oil zone to sweep oil. Injector (I3, I4) we have to open it in the followed month on December 2010 in oil zone to sweep oil and to prevent the solution gas expansion.

Cumulative oil production after 10 years of production is 19.3 MM barrels of oil. It is around 8.11% of the initial oil in place. Figure (5), and Figure (6) showing recovery factor and total field oil production, respectively. The field production has nearly plateau of 2652.4 bpd lasts around 3 years and after that started to decrease. There are some fluctuations in production rate at the time during the field production plateau. That fluctuation happens because of increasing water cut and increasing of gas-oil ratio. There is a time lag between the start of injection and the increase in production (the oil rate increasing due to an increase in reservoir pressure). Figure (7) shows the field oil production rate and Figure (8) shows the field reservoir pressure.

When the water injection is applied to the reservoir some of gas was liberated which tends to re-dissolved into oil as the reservoir pressure increases. Consequently, the oil production does not immediately increase following the start of water injection. There is initially a "fill-up" period during which volumes of water approximately equal to the volume of free gas initially present in the reservoir.

During the fill-up period a large proportion of the gas will be re-dissolved, and the remainders are being produced at the production wells. The fill-up can be represented by an oil front travelling ahead of and much faster than the water front. Behind the oil front the gas saturation is at its residual value. In the fires time, field pressure performance even though it reached the level of around 605 psi during production life, but final pressure is 575 psi. The effect of putting four injector wells the final reservoir pressure is maintained at 575 psi as shown in Figure (8).

Some producer wells are placed in sand, which has higher gas-oil ratio that could reduce the production of the oil. The expansion of gas inside the oil could be the one of the cause of high gas-oil ratio on that wells besides the solution gas. Generally, when the reservoir pressure has been reduced below the bubble point pressure the gas evolves from solution throughout the reservoir. Once the gas saturation exceeds the critical gas saturation the free gas begins to flow toward the wellbore and gas-oil ratio increases. The Figure (9) shows the field gas-oil ratio.

Maximum water injection rate is 2800 bpd. Water injection rate are set to 1100, 700, 500 and 500 bpd for all injector wells (I1, I2, I3 and I4) respectively. Each injector wells to prevent early breakthrough at producer next to injector. Besides, that is a constraint that maximum allowable water cut is 76 %. If the water cut is higher than 76 % then the well will be close as shown on Figure (10). Consequently, it is better to reduce water injection rate. At first, the solution gas plays an important role. After water injecting the gas solution was stop moving because the water injection are starting to take control, but these resulting the water cut in well increase.

Conclusion

The location of production and injection wells will influence the oil production rate and recoverable reserve. Time management also one of the most important factors which may influence the production. The right time to inject water is very important. Water injection scenario has nearly plateau of 2652.4 bpd and lasts around 3 years after that it started to decrease. The cumulative oil production after 10 years of production is 19.3 MM barrels of oil. It is around 8.11 % of the initial oil in place with the recovery factor of about 6.68% and the final reservoir pressure is maintained at 574 psi. Injector (I1) was located at the external boundary of the reservoir (water zone). According to our results we have found that the yields maximum oil recovery with a minimum produced water and as we have increased the volume of injected water to 1,100 stb/d. The reservoir pressure was raised significantly very high. Therefore, we may conclude that the injection in water zone will gave acceptable result of pressure maintenance. Injectors (I2, I3 and I4) were located at oil formation of the reservoir (oil zone), we have found that the yields maximum oil recovery with a maximum of produced water and the reservoir pressure was significantly increased. So we may conclude that the water injection in oil zone is just to move the oil to forward to the well producer.

Notation

BOPD	Barrel Oil Production Per Day
DX	Dimensions of a Grid Cell in X Direction
DZ	Dimensions of a Grid Cell in Z Direction
DY	Dimensions of a Grid Cell in Y Direction
OOIP	Originally Oil In Place
PG	Pressure Gradient
MFP	Maximum Fracture Pressure
bpd	Barrel Per Day
I1	First Injection Well
I2	Second Injection Well
I3	Third Injection Well
I4	Forth Injection Well
WWIR	Water Well Injection Rate
stb	Standard Barrel of Oil
FOE	Recovery Factor
FOPT	Field Oil Production Total
FOPR	Field Oil Production Rate
FPR	Field Reservoir Pressure
FGOR	Field Gas-Oil Ratio
FWCT	Field Water Cut

References

[1]- Eclipse 2009 Manual.
[2]- Yong, C., Wu, O., Bridle, M. K., Xiao, J., & Klotz, E. (2012), Re-injecting Produced Water Into Tight Oil Reservoirs. Society of Petroleum Engineers. 10.2118/162863-MS. DOI:
[3]- Maxwell, S. (2005), Implications of Re-Injection of Produced Water on Microbially Influenced Corrosion (MIC) in Offshore Water Injection Systems. NACE International.

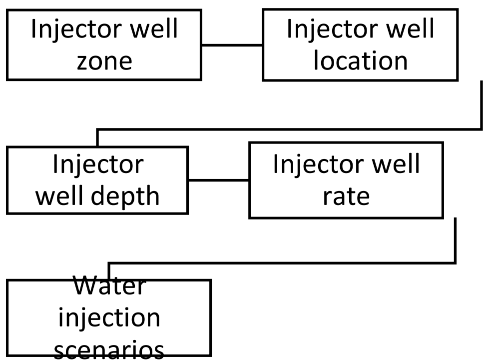

Fig. 1: Methodologies Workflow Used In the Present Study.

Table 1: Maximum Fracture Pressure.

Injector Well	Depth (ft)	PG (psi/ft)	MFP (psia)
Injector (I1)	2964	0.9	2667
Injector (I2)	3078	0.9	2770
Injector (I3)	3187	0.9	2868
Injector (I4)	3017	0.9	2715

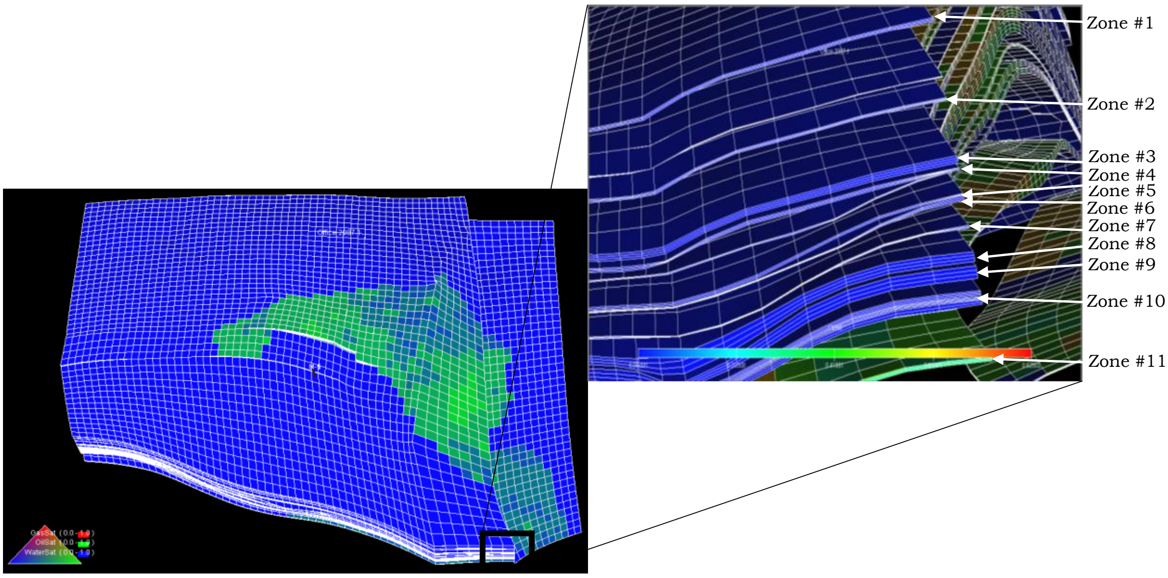

Fig. 2: Zones and Grid Representing the Geological Model.

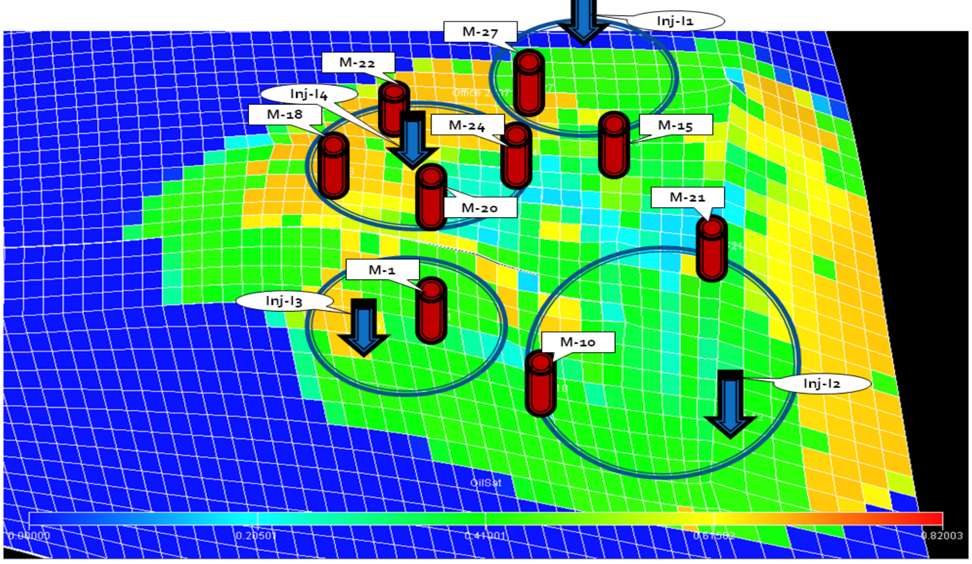

Fig. 3: Well Injection and Production Location and Pattern.

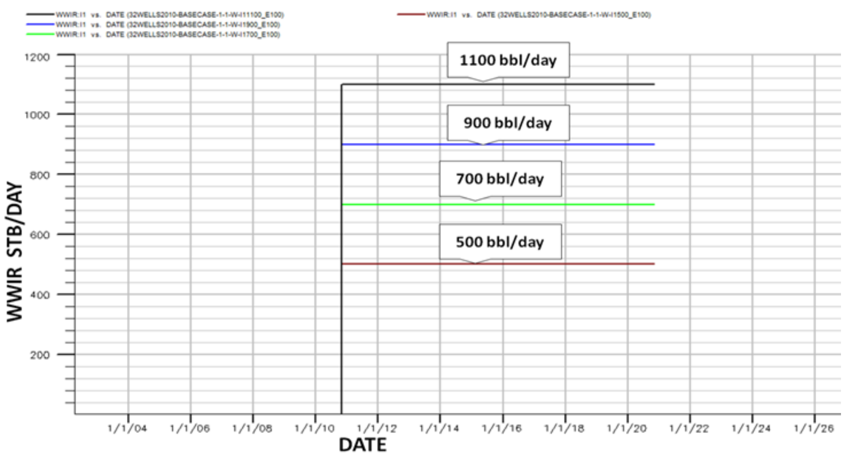

Fig. 4: Water Well Injection Rate of each Injector (WWIR).

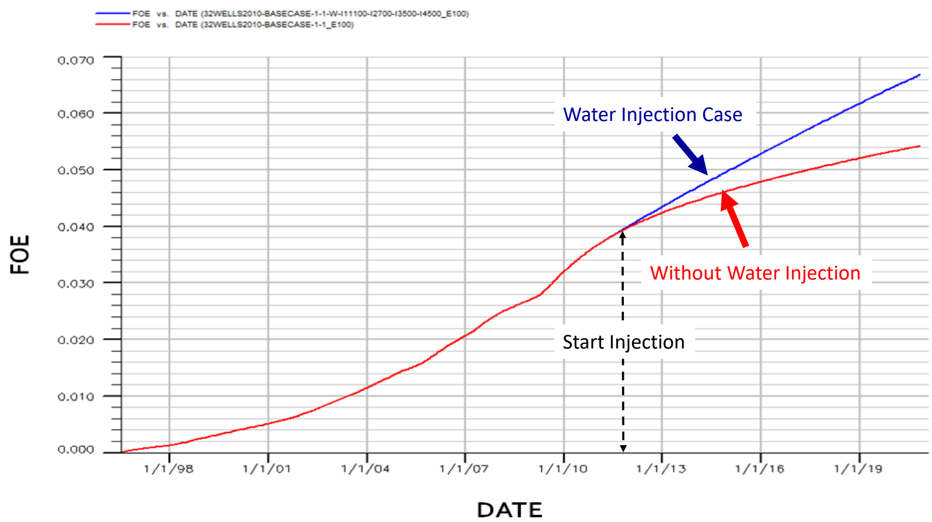

Fig. 5: Recovery Factor (FOE).

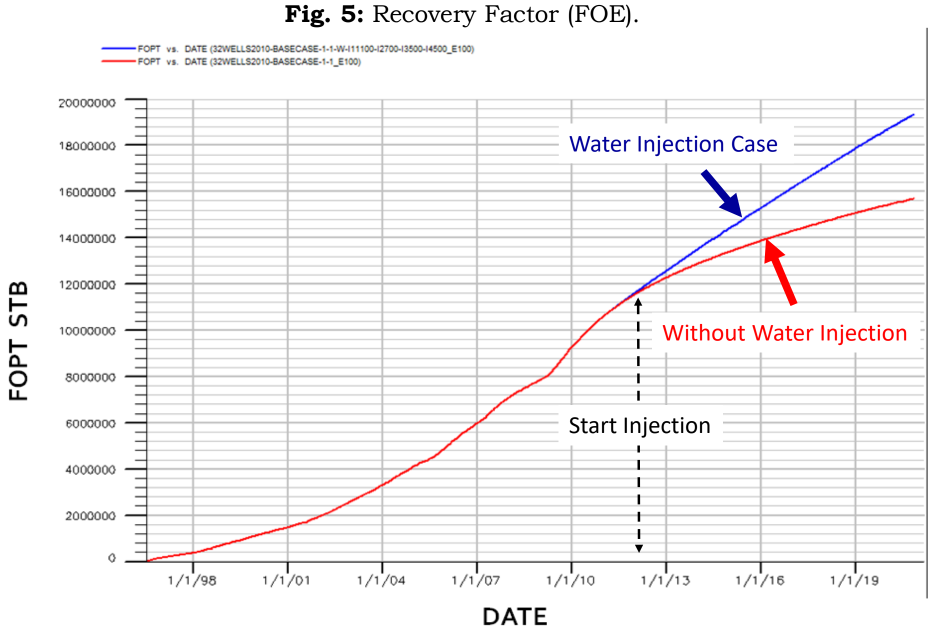

Fig. 6: Field Oil Production Total (FOPT).

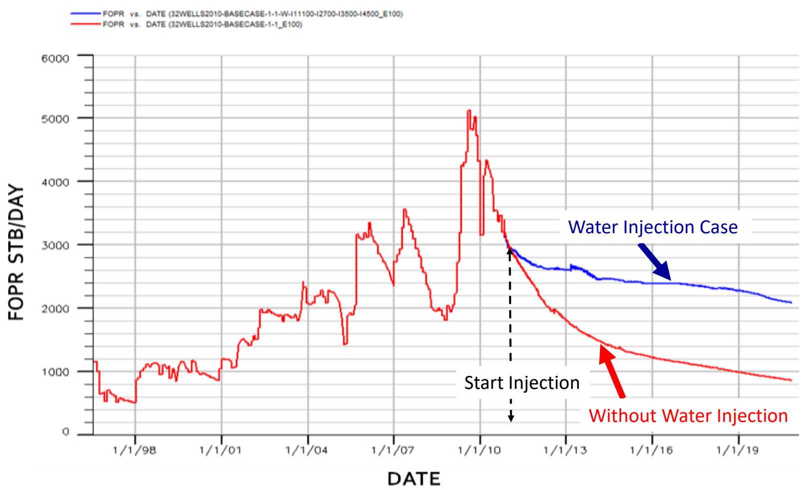

Fig. 7: Field Oil Production Rate (FOPR).

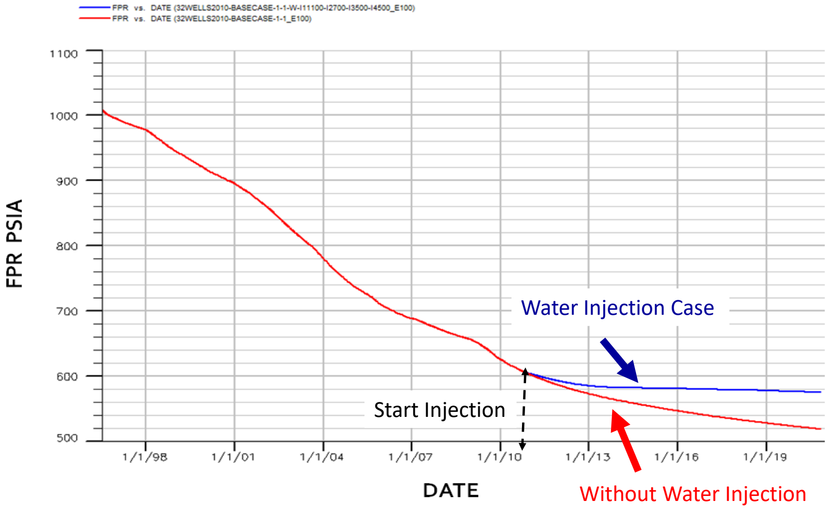

Fig. 8: Field Reservoir Pressure (FPR).

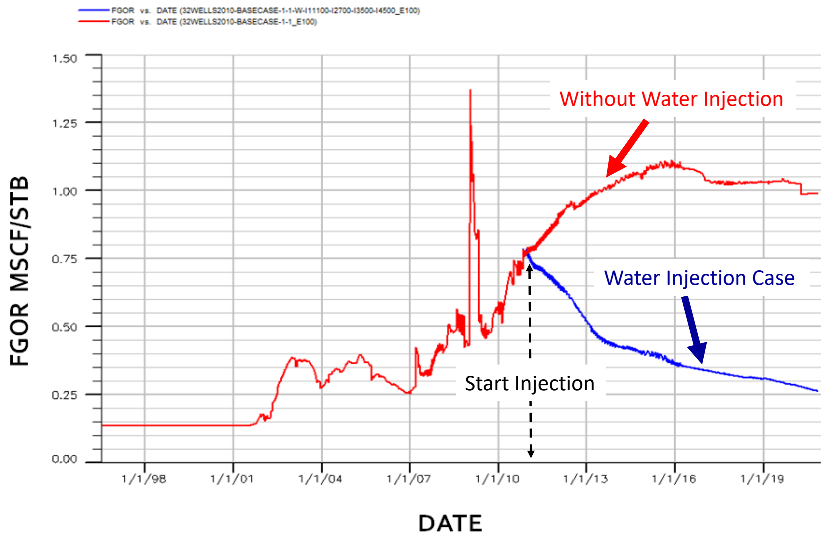

Fig. 9: Field Gas-Oil Ratio (FGOR).

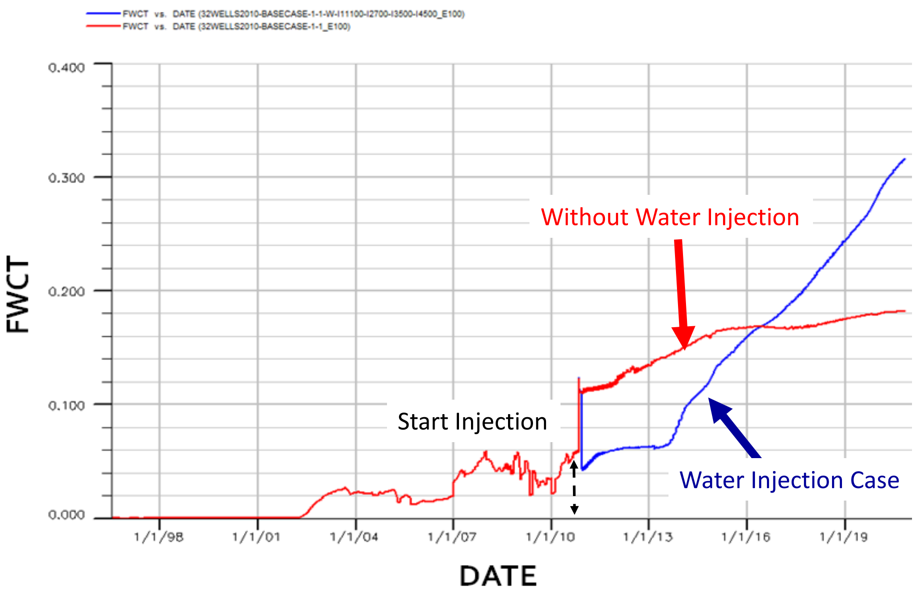

Fig. 10: Field Water Cut (FWCT).