# IMPROVING HORIZONTAL AND VERTICAL SWEEP EFFICIENCIES IN ENHANCED OIL RECOVERY TECHNIQUES USING FRACTURING

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## ABSTRACT

The industry has developed methods to improve the sweep efficiency during EOR processes. These methods include the use of certain patterns, as well as horizontal or deviated wells. The goal of these processes is to create an even movement of injection fluid across the reservoir. Special chemicals have been used to divert the injected fluid to eliminate channeling and to improve sweep efficiency. This paper will present a new methodology to modify sweep patterns to positively impact recovery.

The technique that is presented creates a mechanical barrier to flow by fracturing the formation at a strategic location. We illustrate the potential productivity increase of producing wells as a result of enhancing the horizontal and vertical sweep of the hydrocarbon. The paper also demonstrates that the combination of the barrier fractures with other developed tools, such as inflow control devices and internal control valves, would further improve the productivity and economics of the system.

## INTRODUCTION

Conformance treatments involve mechanical or chemical approaches to control the unwanted water or gas production. They are performed on the producing, injection, or both wells. The treatment may involve minimizing or eliminating this unwanted fluid production. The mechanical control may involve the use of a packer. The chemical approaches may be divided into broad groups. The first approach involves the injection of a sealant into the reservoir to fully stop unwanted fluid flow. The other approach involves the injection of RPM (relative permeability modifier) to significantly reduce the permeability to water while keeping the relative permeability to oil fairly intact. Needham et al. (1974), Eoff et al. (1999), and Sanders et al. (1996) are among many others that discussed the various aspects of conformance treatments. Azari and Soliman (1997) discussed the effect of various reservoir aspects on a conformance treatment.

Placement issues and the effect of identifying the underlying reasons behind unwanted fluid production have been discussed by Soliman et al. (2000). The recommended approach is to do the following:

- Diagnostic testing, which may involve a variety of tests, logging, and production history analysis to determine the source of of the problem. Without understanding the reason for the problem, the chances of economic success decline significantly.
- Design of the treatment, including the type and amount of fluid injected. Because of the complex nature of the problem, this step would probably have to be performed using a numerical simulator.
- Economic valuation of the impact of the treatment where the expected production is calculated and economically evaluated.
- Placement of the treatment.

As mentioned above, all conformance treatments are applied at the producer, the injector, or both. Thus, a conformance treatment has a very near-wellbore effect. Ansah et al. (2006) presented some actual field cases that followed the methodology above and were both engineering and economical success.

Azari and Soliman (1997) investigated the presence of a barrier near the producing well; however, the barrier they considered was essentially horizontal. In addition, there was no explanation of how such barrier may be created. In this paper, we will discuss the effect of creating vertical barrier on the productivity of wells and will show how to use those barriers to modify the flow profile deep in the reservoir.

## FLOW PROFILE MODIFICATION DEEP IN THE RESERVOIR

Creating vertical or horizontal flow barriers deep in the reservoir may have a more significant effect on well and reservoir productivity than a near wellbore-treatment. It would not only be applied to reduce or eliminate unwanted fluid production, but it may be used to improve the areal and vertical sweep efficiency. Because of the potential high cost of creating the flow barriers, this technique may be more applicable to larger reservoirs.

## WHY DEEP MODIFICATION OF FLOW PROFILE

Water injection as a means of improving recovery in oil-producing reservoirs is common. In Saudi Arabia, for instance, water injection has been proven effective in sustaining bottomhole pressure of solution-gas reservoirs for many years. More recently, a typical field would be comprised of water-injected, horizontal wells placed around the flanks of the reservoir with horizontal, transversal producing wells, like the early Permian Basin in Central Arabia..

A potential problem, however, with large-scale water flooding and pressure-maintenance projects is water breakthrough resulting from poor sweep efficiency caused by high-permeability layers in the reservoir and/or a high-mobility ratio. Water breakthrough can lead to early abandonment of unswept portions of the reservoir because of the increased operational costs involved in producing, workover, separating, and re-injecting the produced water.

Commonly-applied solutions for remediation of early water breakthrough have involved extensive engineering efforts. First, diagnosing the breakthrough mechanism to determine the cause of water breakthrough often requires production logging, monitoring produced water for tracers, drilling monitor wells, cement evaluation, and reservoir simulation. Remediation techniques, such as sealants, permeability modifiers, cement squeezes, side tracking, choke-setting reduction, or abandonment, are then applied. In some cases, modifying the injection program can lead to some success if it has been determined that the water is coming from a nearby injector. These solutions may also be costly in some cases and will often act to temporarily arrest water encroachment because these treatments are applied most often to the near-wellbore area of the offending producer.

In some instances, the water breakthrough can be addressed from the injector by changing the injection profile chemically or mechanically. Changing it chemically can be performed using cement or polymer squeezes to block injection into high-permeability streaks or by modifying the mobility of the injected water with polymers or relative permeability modifier chemicals. Changing the injection profile mechanically can be performed using blank pipes. The difficulty with these processes is that it can take years to evaluate the effectiveness of the results, depending on the distance between the injection and producing wells or the flow-capacity level of the reservoir.

Non-uniform influx from the reservoir, especially into horizontal wells, can result in early water/gas breakthrough into a section of the wellbore, leaving valuable reserves in the ground. Inflow control devices (ICDs) and inflow control valves (ICVs) are designed to improve completion performance and efficiency by “balancing inflow or controlling the production around the wellbore” and throughout the length of a completion (Thornton et al. 2010, Augustine and Ratterman 2006, Augustine et al. 2008, and McIntyre et al. 2006). In general terms, water-intrusion control with ICDs and/or ICVs is performed by controlling the discrete and total production rate from the producing well. Though these controls, combined with unique well placement strategies, have proven value in improving ultimate recovery, the opportunity for further improvement exists through creation of reservoir heterogeneity deep into the reservoir.

## BARRIER FRACTURING

One of the innovative ideas in modifying flow is to place a fracture with essentially zero permeability to divert the flow of a displacing fluid such as water. The barrier frac may be created in a variety of ways. One way is to inject a conformance fluid during the later stages of the fractures. A conformance fluid may be injected as fairly low viscosity fluid. The viscosity of the conformance fluid may be as low as 0.5 cp; however, after gelling, the viscosity of the gelled conformance fluid may be as high as 500,000 cp and behave like a Bingham plastic fluid. The goal of creating a barrier frac is to delay the breakthrough of the displacing fluid, which would result in higher areal and vertical sweep efficiency. This goal may be implemented in multiple ways. One approach as discussed by Sierra et al. (2010) and East et al. (2011) can be done in conjunction with existing horizontal and vertical wells. Another approach is to create the barrier fracture merely for the sake of changing direction of flow using a new well drilled for that purpose. The second approach was filed as a patent by Soliman et al. (2010).

## BARRIER FRACTURE PLACEMENT

Fracture placement can be accomplished in an open hole during the drilling phase of the well or in a cased hole as part of a completion procedure. Barrier fracturing can be accomplished during any phase of the completion with a modified version of the currently-available technology, and multiple barrier fractures may offer substantial benefits throughout the life of the reservoir, depending on the injector/producer well patterns. This allows the operator much greater flexibility when designing a water-flood project while improving overall sweep efficiency and minimizing the number of producers required.

## PROFILE MODIFICATION IN CONJUNCTION WITH HORIZONTAL WELLS

Sierra et al. (2010) and East et al. (2011) investigated two approaches for production from a fractured horizontal well and another in the presence of a vertical well. The two scenarios are given in Figs. 1 and 2.

## RESERVOIR SIMULATION – SINGLE HORIZONTAL WELL WITH VERTICAL WELL INJECTOR

Sierra et al. (2010) illustrated the value of using barrier frac for a single horizontal along in the presence of a vertical well. They went further and combined the barrier frac with the use of ICDs and ICVs.

**Table 1** gives the reservoir properties used by Sierra et al. (2010) in their numerical simulation. Remember that there are numerous combinations of reservoir properties, and this analysis or our expanded analysis may only be used as illustration of the validity of the techniques presented in this paper. **Table 2** presents the various completion scenarios studied by Sierra et al. (2010).

The production rate for each producer in scenarios 1-6 was limited to 10,000 bpd of water plus oil maximum, and the injection rate was set at 10,000 BWPD. The vertical injection well in all scenarios was simulated as an open-hole completion. The vertical well was completely penetrating the production interval. The 2,000-ft horizontal lateral was placed at 2,015 ft vertical depth.

## RESULTS – SINGLE HORIZONTAL PRODUCER WITH VERTICAL INJECTOR – SCENARIOS 1-6

The cumulative oil production for the ten-year production period varied from 29,502,496
bbls for Scenario 1 base case with no inflow controls to 36,408,517 bbls for Scenario 6 with 5 barrier fracs, ICDs, and ICVs controls—an improvement of 23.4% with an increment oil recovery of 6,906,020 Bbls (see **Fig. 3**). The benefit to the daily oil production rates for scenarios 1-6 is illustrated in **Fig. 4**.

The cumulative water production for the ten-year production period with 10,000 bwpd water injection varied from 7,022,504 bbls for Scenario 1 base case with no inflow controls to 116,481 bbls for Scenario 6 with 5 barrier fracs, ICDs and ICVs controls—a reduction of 6,906,023 bbls of produced water (see **Fig. 5**). The timing of the flood front water breakthrough and control of water production can be determined for each scenario in **Fig. 6**. The stair step changes observed in scenarios 3 and 6 are due to closure of the ICVs as response to an increase in water cut. The figures clearly show the effect of using the barrier frac concept with and without ICDs on the sweep efficiency. The flow condition of those cases assumed constant total flow rate (oil plus water), which resulted in an increase in oil production that was equal to the decrease in water production.

## DEEP RESERVOIR PROFILE MODIFICATION

As mentioned earlier, deep reservoir alteration of flow profile may have a more significant effect on productivity than near-wellbore alteration of injectivity or productivity using sealants. Several cases have been run to illustrate the effect of deep reservoir barrier.

## FIRST CASE – EDGE WATER DRIVE

Many reservoirs have strong-edge water drive, and depending on the strength of this edge water drive, water coning may occur early, essentially ending the oil productivity of a well. In the first, case we will examine a reservoir with edge water drive where a horizontal well has been drilled to produce the reservoir. The reservoir grid is given in **Fig. 7**. The comparison of the saturation profile in the presence and absence of a barrier fracture in **Figs. 8** and **9** clearly shows the improvement in sweep efficiency by creating the barrier fracture. The increase in oil production and decrease in water production are given in **Figs.10** and **11**.

Simulation using QuikLook® service indicates that the oil production will increase by 213,000 STB (5.35%), and decrease in water production will be about the same amount, 213,000 bbl, (6.41%). At $80/STB, the increase in oil production is worth almost $17,000,000 in revenue. The decline in water production is worth almost $500,000 of disposal cost. The net increase in revenue should more than pay for the cost of drilling and fracturing a new well.

### SECOND CASE – LINE DRIVE WATER-FLOODING PATTERN

In the second case, a line-drive reservoir with two wells, an injector, and a producer were simulated. A third well was drilled, and a fracture was created and placed in the middle of the reservoir. The fracture extended as shown in **Figs. 12** and **13**. Those two figures also show the improved displacement profile resulting from the creation of the barrier fracture. **Figs. 14** and **15** illustrate the increase in oil production and decline in water production. The two figures also indicate that optimization of the fracture position and dimension may be very important in the optimization process.

### THIRD CASE – FIVE SPOT WATER FLOODING PATTERN

Third case was set for a 5-spot pattern. The reservoir grid is given in **Fig. 16**. The comparison of the saturation profile in the presence and absence of a barrier fracture in **Figs. 17** and **18** clearly shows the improvement in sweep efficiency by creating the barrier fracture. The increase in oil production and decrease in water production are given in **Figs. 19** and **20**.

Results are illustrated in the figures below. The use of one barrier increased total production over the 20-year life of the well by over 9%. Assuming $80/STB oil, the increase in production is equivalent to increased revenue of over $24,000,000.

### OPTIMIZATION OF THE BARRIER FRACTURE LOCATION

The location of the barrier fracture has a direct effect on the total sweep efficiency. The optimization of the location of the well will be studied for the 5-spot water flooding case discussed as case 3. The result for barrier fracture optimization study is illustrated in **Figs. 21** and **22**. The figures indicate that the optimum location of the barrier fracture is right at the center of the two well. **Fig. 23** gives a more detailed picture of the optimization process. The figure also indicates that the final outcome is not terribly sensitive to the location of the barrier fracture.

## CONCLUSIONS

This paper has shown that creating barrier fractures for the purpose of modifying flow regime deep into the reservoir has the potential of significantly increasing oil production while delaying water breakthrough. The application is not limited to specific reservoir type or completion. It may be applied to a wide variety of conditions, such as edge water drive, and various patterns of injection. The paper examined the effect on water flooding; however, the technique would work equally well for other of enhanced oil recovery, such as system injection, gas injection, miscible flooding, etc. The location of that barrier is also important, as shown in the paper. Although not shown, the timing of creating this barrier should have some effect on the final sweeping efficiency.

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Table 1
Reservoir Properties Modeled – Scenarios 1 through 6

| **Properties** | | **Properties** | |
|---|---|---|---|
| Reservoir Fluid | Black Oil | Depth to top | 8,000 ft |
| Oil API Gravity | 40 | Depth to bottom | 8,080 ft |
| Gas-Oil Ratio | 700 scf/bbl | Rock Compressibility | 3.0 E-06 psi$^{-1}$ |
| Water Specific Gravity | 1.0 | Initial Res. Pressure | 3,840 psi |
| Gas Specific Gravity (air=1.0) | 0.7 | Bubble Point | 3,300 psi |
| Irreducible Water Sat. | 0.2 | No Flow Boundary | West, Top, Bottom |
| Residual Oil Sat. | 0.1 | Constant Pressure | North, East, South |
| Vertical Well TVD | 8,080 | Reservoir Size | 1 mile X 1 mile |
| Injector Open-hole Depth | 8,000 – 8,080 ft | Horizontal Well TVD | 8,017 ft |
| Injection Period | 10 years | Producer Lateral Length | 2,000 ft |
| | | Production Period | 10 years |

Table 2
Water flood Completion Simulation Scenarios

| Scenario | Producer | Controls | Injector |
|---|---|---|---|
| 1 | Horizontal | none | Vertical |
| 2 | Horizontal | ICDs | Vertical |
| 3 | Horizontal | ICDs & ICVs | Vertical |
| 4 | Horizontal | One NCBF at Toe | Vertical |
| 5 | Horizontal | ICDs and Five NCBF | Vertical |
| 6 | Horizontal | ICDs, ICVs & Five NCBF | Vertical |

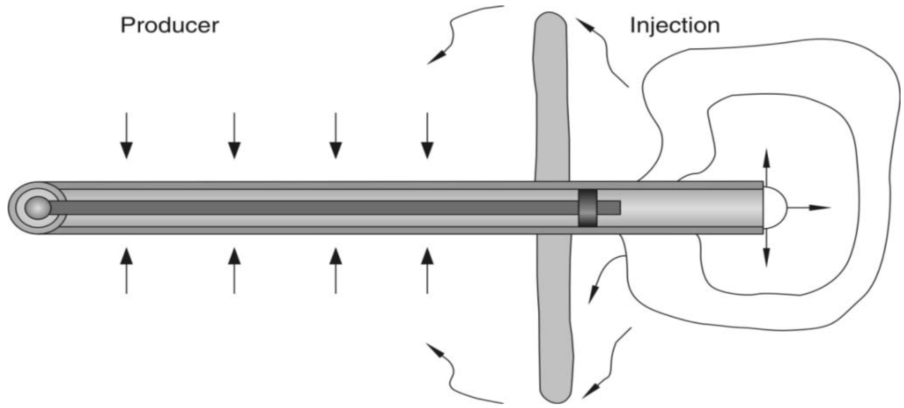


Figure 1—Injection and Production using a Single Wellbore, After Sierra et al. 2010

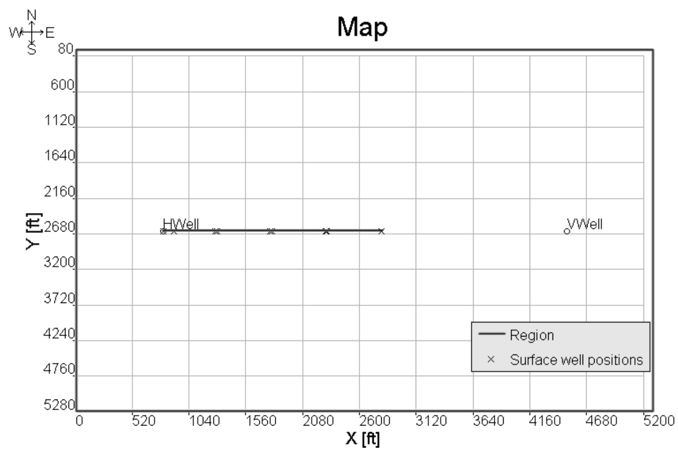


Figure 2—Map of Horizontal Producer with Vertical Injector, After Sierra et al. 2010

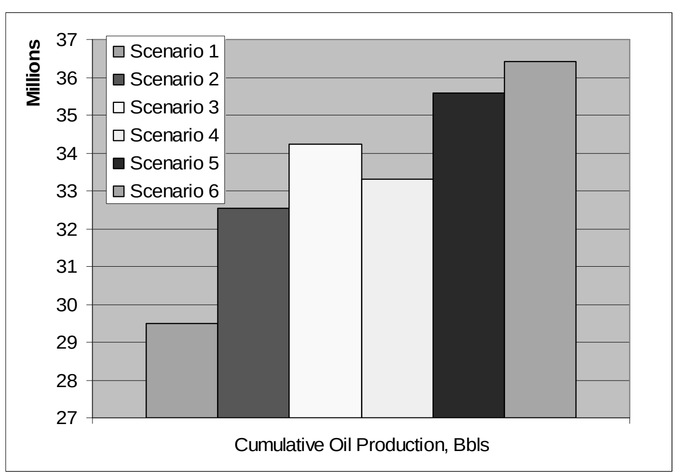


Figure 3—Cumulative Oil Production Comparison

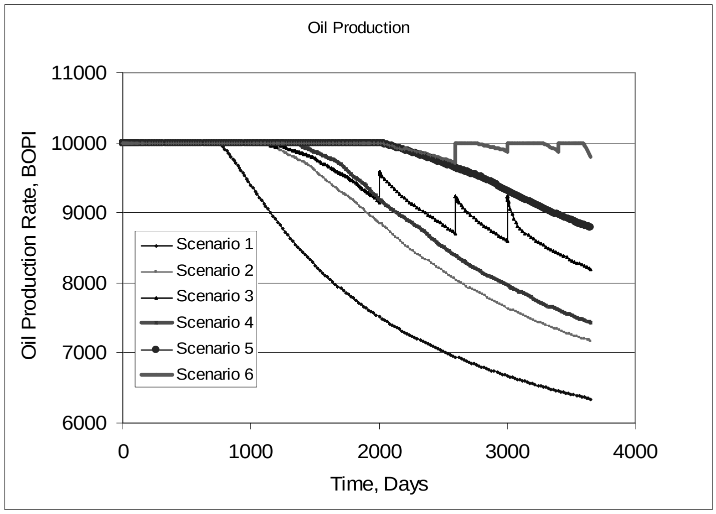


Figure 4—Daily Oil Production Rate for All Scenarios

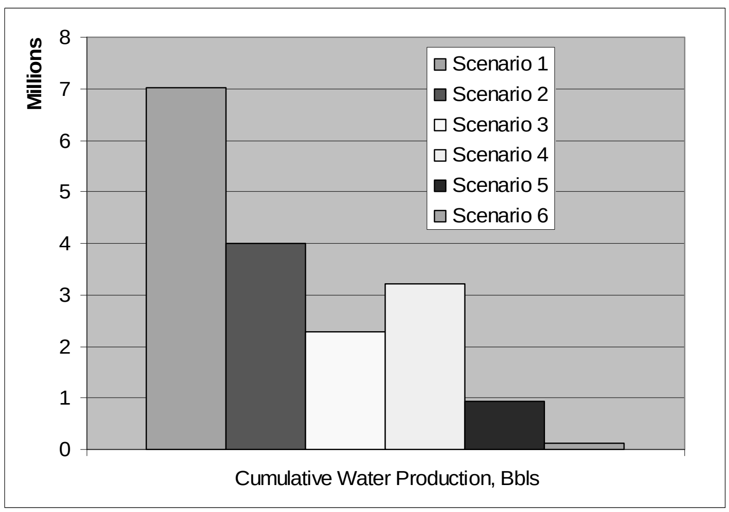


Figure 5—Cumulative Water Production Comparison

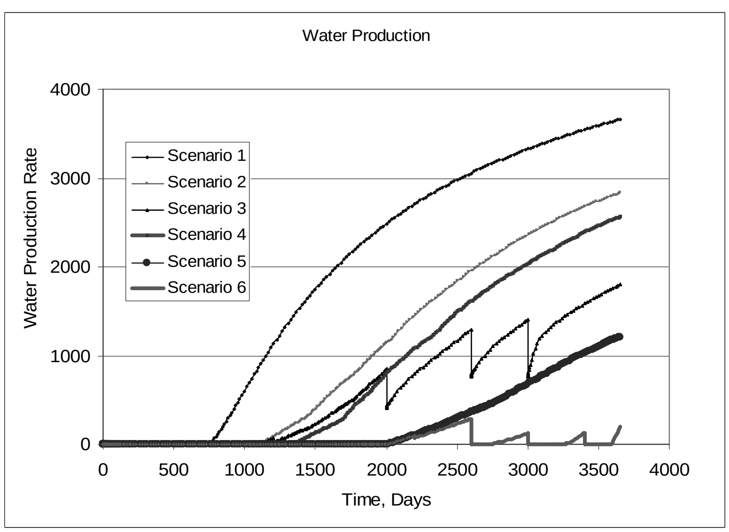


Figure 6—Daily Water Production Rate for All Scenarios

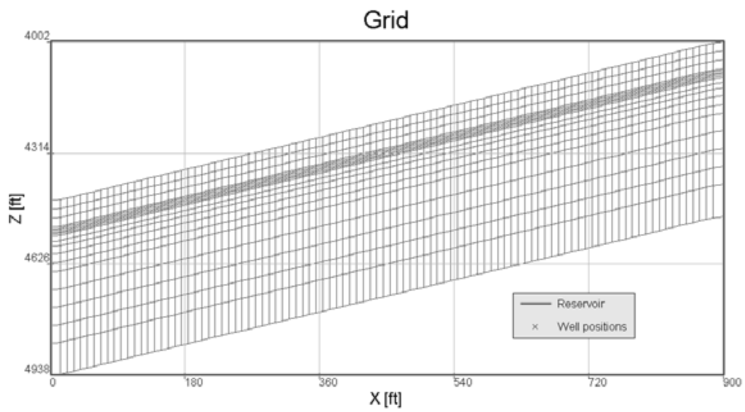


Figure 7—Reservoir Grid with Edge Water Drive

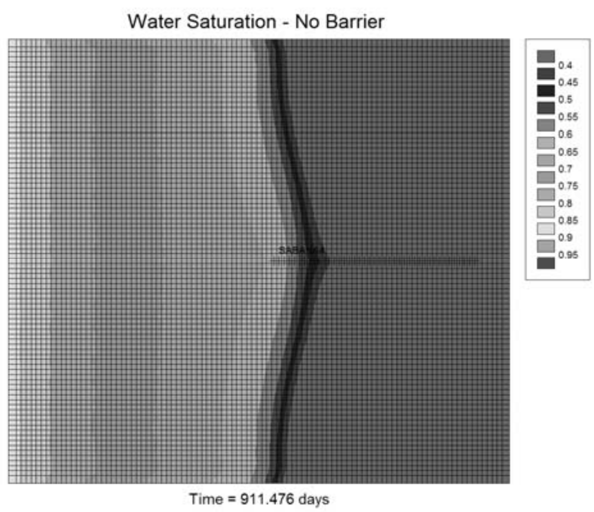


Figure 8—Water Breakthrough into the Horizontal Well When No Barrier Exists

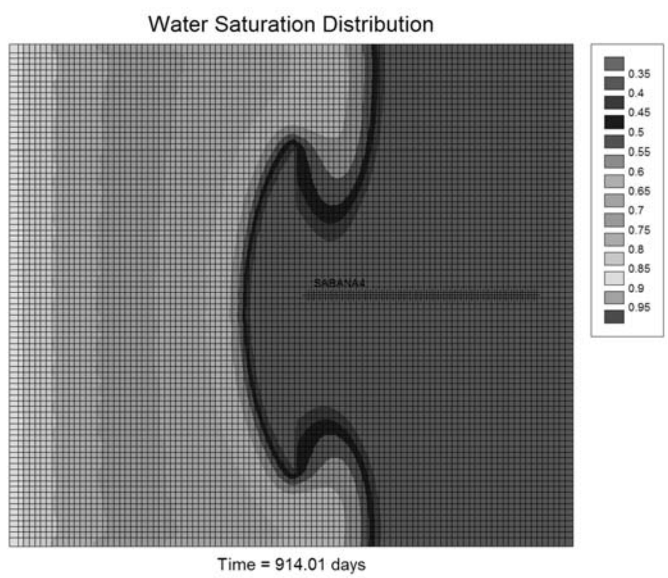


Figure 9—Water Breakthrough into the Horizontal Well in the Presence of a Barrier Fracture

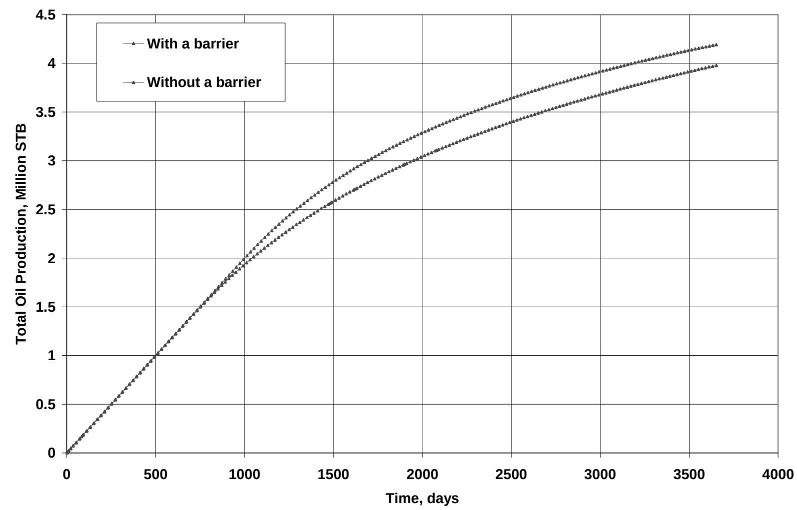


Figure 10—Oil Production in the Presence and Absence of a Barrier Fracture

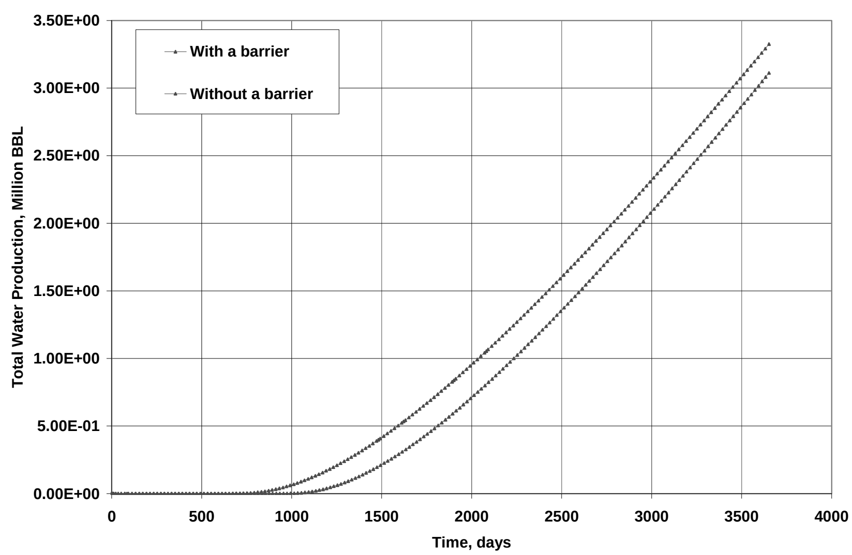


Figure 11—Water Production in the Presence and Absence of a Barrier Fracture

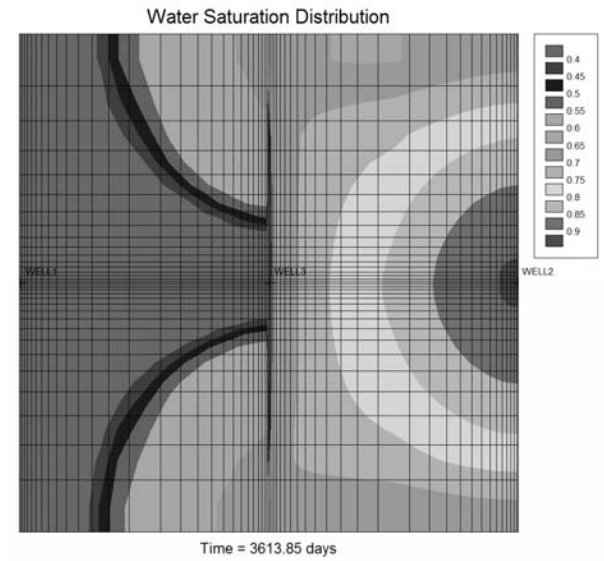


Figure 12—Planar Water Saturation Distribution in the Presence of a Barrier Fracture

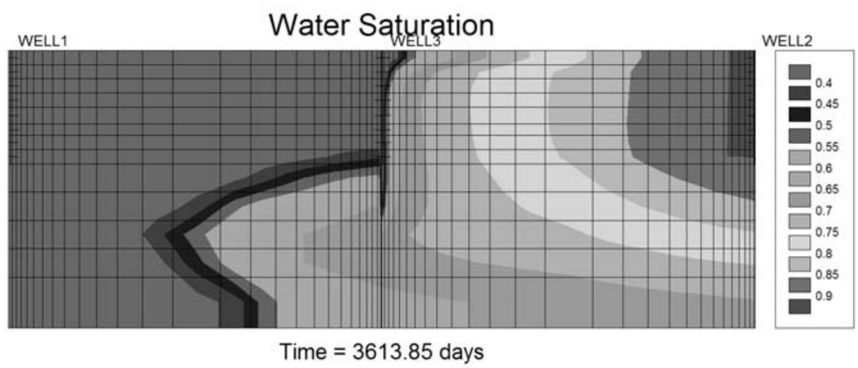


Figure 13—Cross-Sectional Water Saturation Distribution in the Presence of a Barrier Fracture

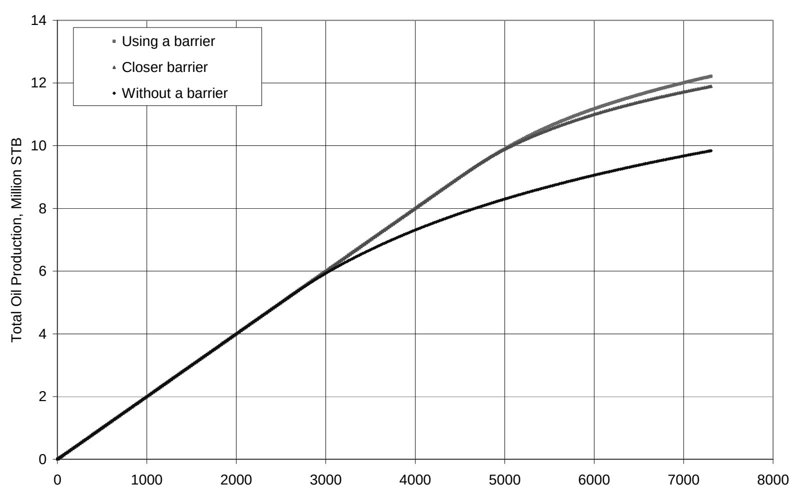


Figure 14—Oil Production in the Presence and Absence of a Barrier Fracture

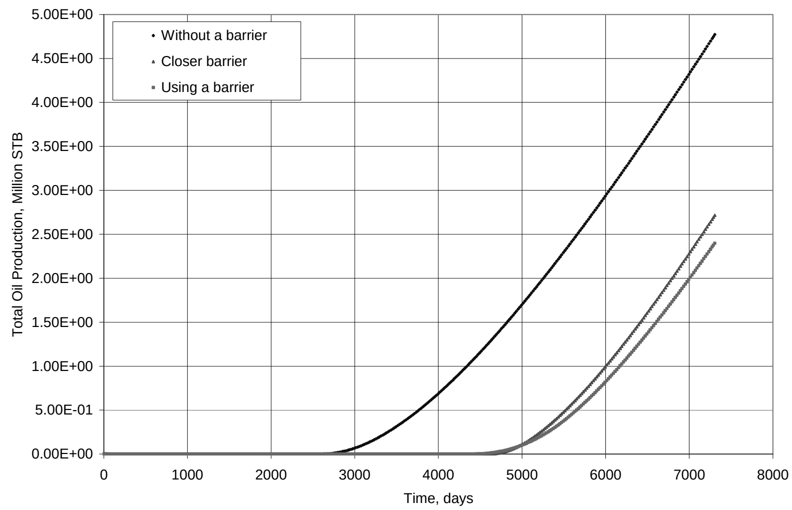


Figure 15—Water Production in the Presence and Absence of a Barrier Fracture

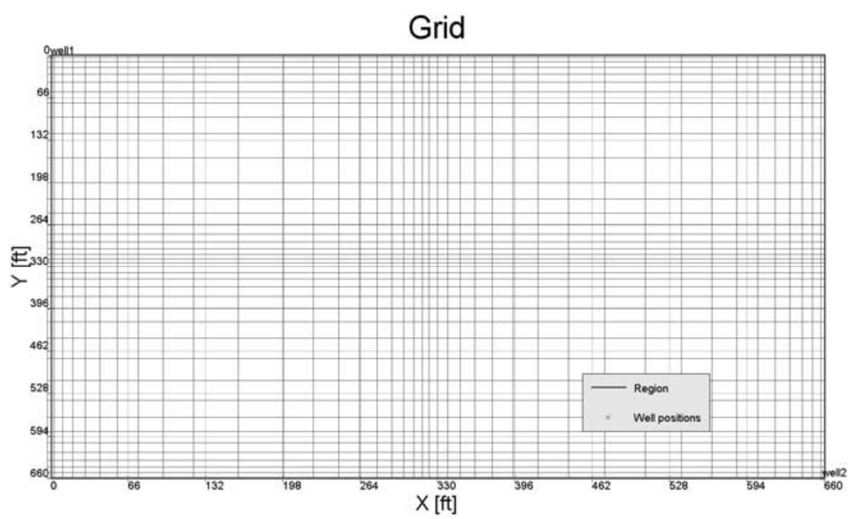


Figure 16—Reservoir Grid with Five-Spot Pattern

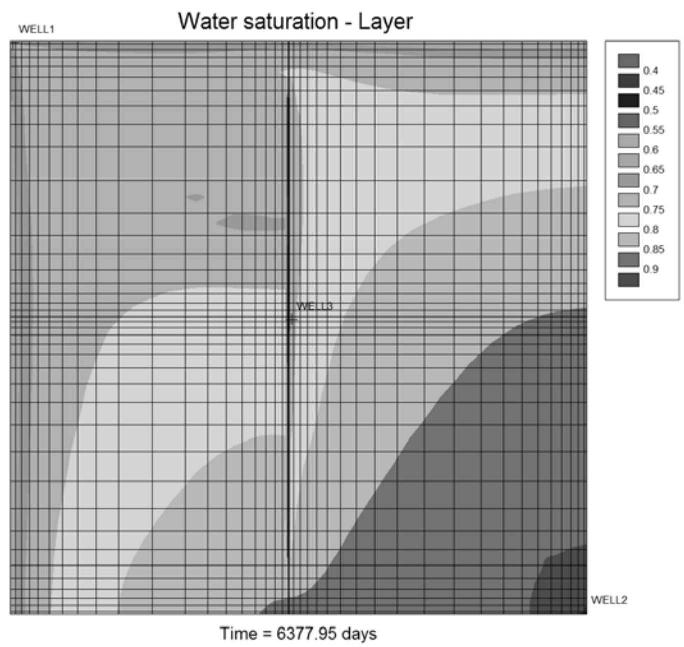


Figure 17—Water Saturation Distribution in the Presence of a Barrier Fracture

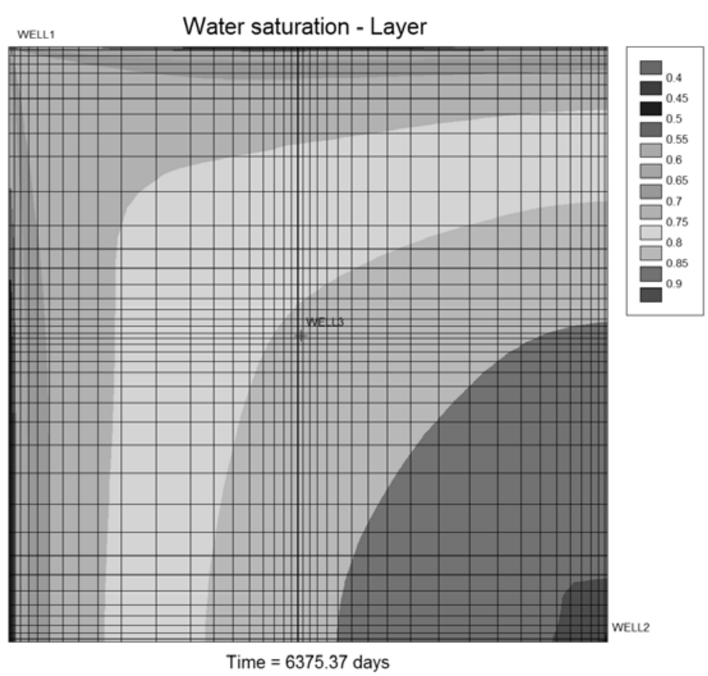


Figure 18—Water Saturation Distribution in the Absence of a Barrier Fracture

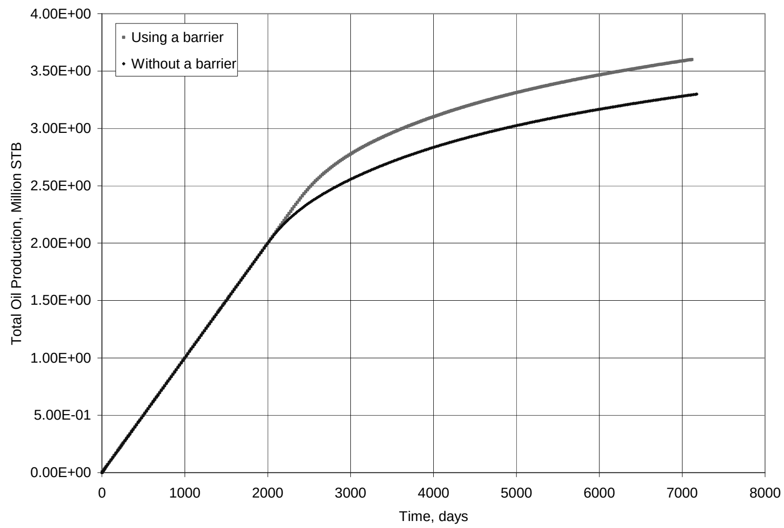


Figure 19—Oil Production in the Presence and Absence of a Barrier Fracture

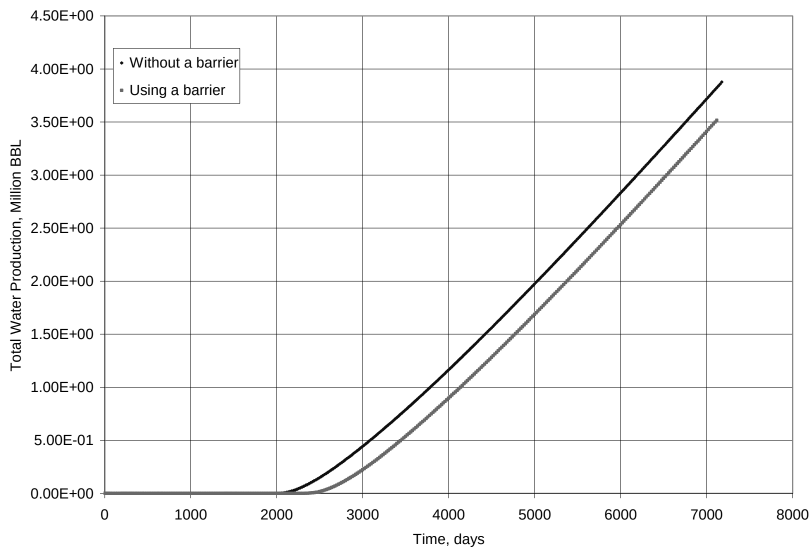


Figure 20—Water Production in the Presence and Absence of a Barrier Fracture

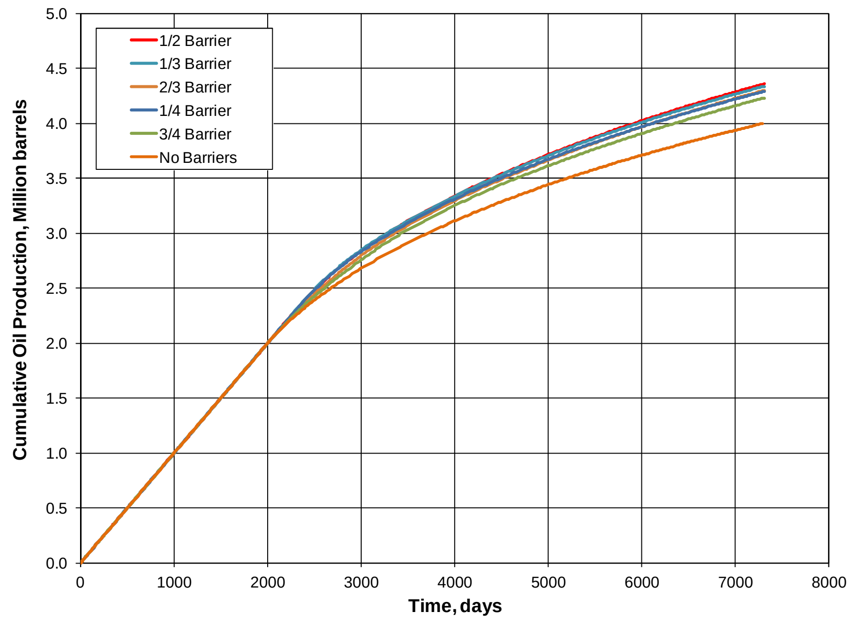


Figure 21—Effect of Location of Barrier Fractures on Oil Production

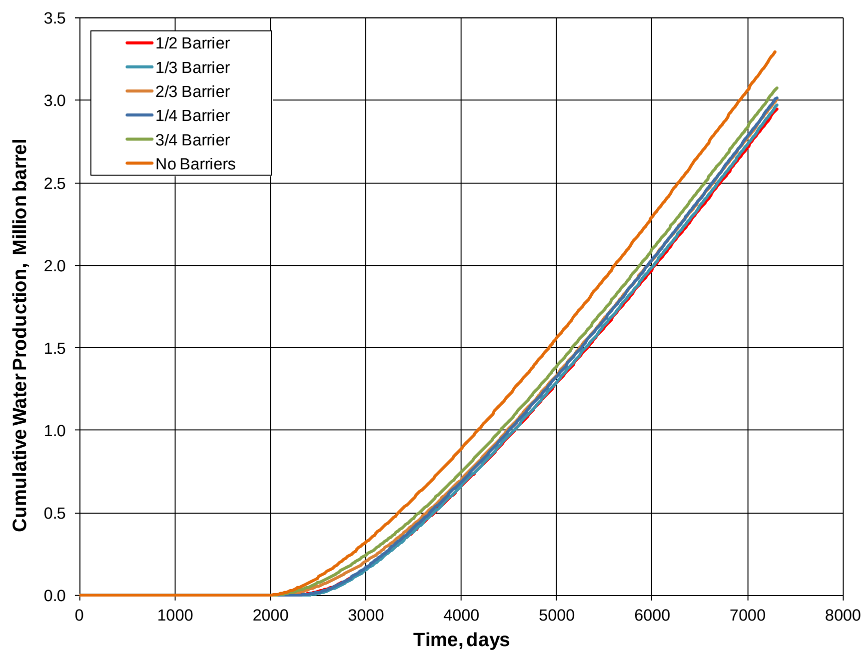


Figure 22—Effect of Location of Barrier Fractures on Water Production

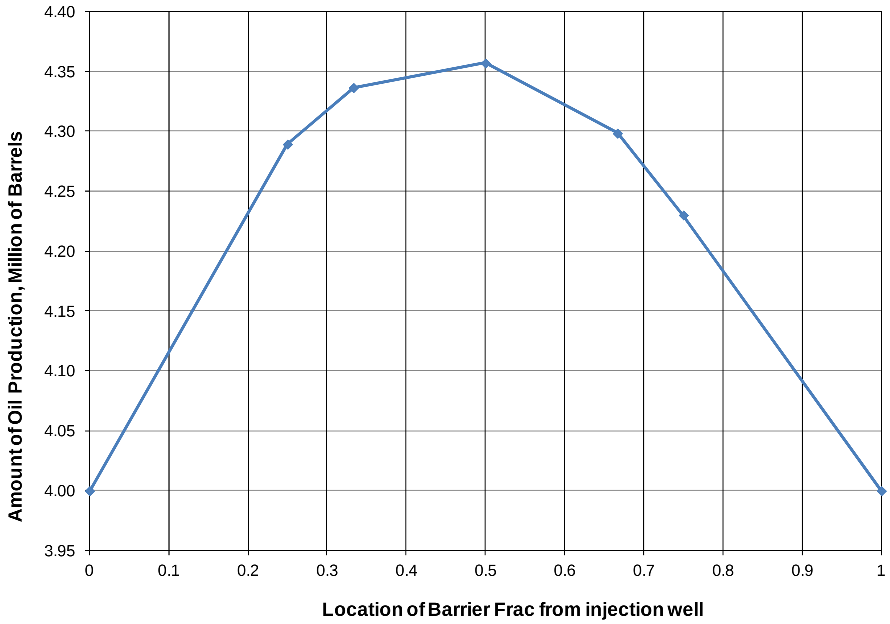


Figure 23—Effect of Location of Barrier Fractures on Oil Production