EFFECTIVE FRACTURE PLACEMENT IN HORIZONTAL WELLS

Timothy McNealy and Ken Borgen
Halliburton

ABSTRACT

Stimulation techniques in horizontal wells are a topic of great interest and discussion (Soliman et al. 1990; Soliman et al. 1996; Surjaatmadja et al. 1998; Love et al. 2001). With a large variety of different stimulation practices/techniques being performed (slickwater, gelled water, foam fracturing in a cased or open hole, using ball-activated sleeves, or plugging and perforating, etc.), the effects of fracture spacing in horizontal wells when determining the most effective methods for increasing oil/gas production is often not included in the stimulation design.

After reviewing a well's production performance using a reservoir simulator, it was apparent that a large portion of the horizontal interval was not being effectively drained and therefore not contributing to the well's overall production. This lack of drainage can result in low estimated recoverable reserves. With the aid of a fracture simulator, reservoir simulator, logging data, and local core data, a process was developed for determining the optimal horizontal well-fracture spacing. Determining the most effective fracture spacing on a horizontal interval has shown to boost production by increasing the estimated recoverable reserves within a given drainage area.

INTRODUCTION

Investigating a horizontal well's oil production on an artificial lift pump can present a challenge in quantifying the effectiveness of any stimulation treatment. This can be done; however, determining the effectiveness can be difficult. To improve the effectiveness of stimulation, it is necessary to establish the number of fractures needed and the placement of each fracture. This can be accomplished by coupling a fracture simulator with a reservoir simulator to establish a valid model for predicting the optimal stimulation treatment and fracture placement in horizontal wells.

Any and all information collected about the reservoir should be used in the effort, and any assumed values of unknown variables should remain constant throughout the process. The use of core data to measure capillary suction time is crucial in determining the most effective fracturing fluids for maximizing regained permeability.

Reviewing past stimulation treatments with a fracture model by pressure matching the actual well treatment pressures against the simulated treatment pressures can be used to approximate fracture dimensions and conductivity. Once the treatment match has been made, the obtained fracture can be optimized with the use of production index curves and/or a fracture simulator. The resulting dimensions and properties of the fracture can be used in a reservoir simulator to get a better idea of how the reservoir is behaving after stimulation. Then, by matching the reservoir simulation's production with the actual production, a working model for future predictions has been established.

The optimized fracture can then be used in the production-matched reservoir simulator to determine the needed amount of fractures to effectively drain the horizontally completed reservoir, assuming the fractures are perpendicular to the wellbore.

CORE TESTING AND PORE PRESSURE

In the Permian Basin, there are some minerals that can generate negative effects caused by exposing a particular fluid to them. Fluid contact on clay particles can cause formation damage. The current hydration state of the clay particles will influence whether any formation damage is created as a result of exposing it to any fluids. Minerals like hematite, pyrite, siderite, illite, kaolinite, montmorillonite, chlorite, and muscovite can possibly create formation damage just from exposure to a fluid. Some fluid characteristics to consider when determining fluid compatibility from permeability testing are charge (salt type), pH, wettability, surface tension (capillary bound pressure), and reservoir water saturation. It is important to note that the use of deionized water as a core permeability baseline is critical in observing the effects of the ionic exchange between the fluid and the core sample. Unfortunately, these tests are either neglected or performed late in a development program, thus creating formation damage while stimulating, which is obviously counter productive. Performing all the necessary research upfront can save a great deal of lost production and narrow down the unknowns if the production is different than anticipated. The compatibility between formation hydrocarbons and stimulation fluids can not be stressed enough; neglecting to perform prejob hydrocarbon and stimulation fluid-compatibility testing can result in nonreversible effects. Core testing can assist in differentiating poor performance caused by formation damage from the effects of fracture density.

The reservoir's pore pressure when the well is completed should be the values used in the reservoir simulator. This might sound trivial, but unfortunately this value is rarely determined using pore-pressure wireline tools, drillstem testing, or pressure-buildup tests. Assuming this value incorrectly can result in major errors in every aspect of reservoir engineering. Using an incorrect pore-pressure value during this process would result in major production-rate errors which are used in the initial calibration of the model.

HYDRAULIC-FRACTURE MODELING (HFM)

An important aspect to hydraulic-fracture modeling is data collection. Openhole logs play a large role in HFM. Using logging interpretation/analysis software to generate rock mechanical properties and layers for modeling will assist in establishing consistency in modeling. Limiting the adjusted variables in a hydraulic-fracture simulator will also increase consistency if the same variables and log analysis are used for a specific formation in a particular field. For example, varying the tip-effects coefficient and composite layering-effect values to obtain a pressure match, while leaving all the other model variables constant, can reduce the complexity in the model. Sometimes, hydraulic-fracture models cannot be used to describe complex fracturing and the anisotropy of the formations. These properties can make the outcome of a stimulation treatment unpredictable. HFM confidence can come from a variety of sources: openhole logging, sonic data (correlation for rock mechanical properties and possible hydraulic-fracture orientation), core data (rock mechanical properties, fluid compatibility and permeability), tracer surveys (hydraulic-fracture height and limited entry effectiveness), microseismic survey (extent of hydraulic-fracture length, height and possible hydraulic-fracture orientation) and injection tests (leakoff type and permeability).

There are various theories on net-pressure matching HFM. Most of them agree that the first instantaneous shut in pressure (ISIP) observed after the initial injection is a solid point with which to match up. Some formations are easier to model than others, but pressure matching the ISIP and the pressure trends (**Fig. 1**) can only add to the idea that the model is a good representation of the induced fracture. The best option for observing net pressure during a job is having a dead string set just above the perforations to monitor and record the bottomhole pressure (BHP). BHP gauges can be used in this configuration or alternatively be attached to packers or bridge plugs. Without a BHP gauge, the BHP is predicted by the calculation of surface and hydrostatic pressures. Having a single HFM that has been fined-tuned to a field that can predict any job would be an ideal case.

One important idea to realize is having the fracture cover all of the pay. As trivial as this might be, the idea can be taken in two different ways. In any well, additional pay zones can exist above or below the current interval of interest. In horizontal wells, obtaining as much vertical pay as possible can make a noticeable difference in production. The other aspect of this idea is that some formations have low permeability, and all the proppant used in the stimulation treatment can settle out of the pay zone by the time the fracture closes and now some of the pay is no longer covered. An example of designing a job to achieve complete vertical pay coverage can be viewed in **Fig. 2**, where the extent of the fracture attempts to vertically cover all the pay. This assumes that the fracture being created is a simple, bi-wing fracture and not a fracture network or a permeability enhancement region (PER). A PER typically is created in low-permeability and brittle formations through the use of low-viscosity fluids and a variation of proppant mesh sizes. The idea behind the permeability-enhancement region is to make the reservoir behave as if it had a higher permeability region some distance away from the wellbore.

The equations derived by Tinsley et al. (1969) for production folds of increase from hydraulic fracturing along with Soliman's (1983) correction for steady-state production is used as an aid in the optimization process. The goal of optimizing any stimulation treatment is to efficiently deplete the largest allowable drainage area during primary production. Assuming the reservoir is homogenous, the largest drainage area is a function of the reservoir characteristics. Attempting to drain beyond this limitation can be costly with little or no increase in the return on investment (ROI).

Some HFM software has Tinsley's production theory included. For the software that does not, the needed hydraulic-fracture properties can still be calculated by using Tinsley's equations along with Soliman's steady-state correction. Pay close attention to any type-curves used to ensure that the correct ratio of fracture height (Hf) to reservoir height (Hi) is appropriate for the case being modeled.

Dynamic proppant conductivity is often overlooked when it comes to proppant design. To achieve the needed conductivity described in Tinsley's curves, any and all damage mechanisms, such as multiphase flow, embedment and, crushing to name a few must be taken into account (**Fig. 3**).

RESERVOIR MODELING

Once a single stimulation treatment has been defined, it can now be used in conjunction with a reservoir simulator to determine the optimal number of fractures that are needed to effectively drain the horizontal length of the wellbore.

A critical component to determining the needed fracture density is the effective drainage area. The effective drainage area can be determined with the use of an analytical or numerical reservoir simulator.

The underlying limitation to drainage area can be seen in **Figs. 4, 5, and 6** as it relates to the interaction between pressure, porosity, and permeability.

Before any predictions can be made, the reservoir model needs to be calibrated to actual production. Regardless of how much the fracture optimization has been refined, production matching with a reservoir simulator before any predictions are made is a critical step. Once the observed production rates are comparable to the model's calculated rates, then the model can be used to predict production from various fracture densities.

In Fig. 7, the results from a reservoir model with four fractures is compared with the well's observed production from four fractures. The additional curves of Fig.7 show the potential improvement that could be gained from other fracture-density scenarios.

Maximizing the estimated recoverable reserves to generate the highest possible ROI is the underlying purpose of any completion. Determining the number of fractures needed to efficiently drain a horizontal well can be achieved in a couple of different ways. The easiest way is to visually inspect the pressure distribution in the reservoir shown by the model over a defined period of time. Ideally, using the minimal number of fractures to uniformly drop the pressure along the horizontal would result in the highest production rate and the highest estimated recoverable reserves. Potentially, obtaining this goal might not be economical because the sum of the initial cost per fracture could outweigh the incremental increase in production.

In Figs. **10, 11, 12, and 13** the completion scenarios of four, seven, thirteen, and twenty-five individual fractures are shown respectively. Achieving the extreme pressure distribution early in the well life, as seen in Fig. 13, could be uneconomical as increasing the density could begin to diminish the ROI per fracture. To arrive at a reasonable solution, an iterative process could be followed to approximate a uniform pressure distribution by increasing the number of fractures along the horizontal wellbore until the desired ROI is reached. An example of this can be seen in **Fig. 8**.

Another method that could be used to determine fracture density is to determine the effective drainage area for a defined time interval. During primary production, the reservoir pressure distribution has a logarithmic decay away from the wellbore. This pressure distribution can be used to determine the preferred pressure differential in the reservoir, which in turn can be used as a reference point for the distance between the fractures.

Regardless of the method used to determine the needed fracture density, it is important to use an iterative process in fracture-density optimization. Quantifying the results with a consistent method is the importance behind this optimization process.

PREDICTION WITHOUT OPTIMIZATION

Thus far, reservoir optimization of previously stimulated wells has been the aim of this process. Fortunately, this process can also be used on new field completions as well as on recompletions in new formations. The initial thought is that the number of reservoir unknowns would be higher in this particular case. Using known area data and any public information of offset wells can help to fill the gap.

To demonstrate this process in another reservoir, a different well in a mature field was selected as a candidate for horizontal recompletions. It is a common practice to review previous stimulation treatments without necessarily knowing the reasoning behind the design. This was the case for Well 1; the perforation, fluid, proppant design, and fracture density all stemmed from an offset well completion.

Data collected for Well 1 consisted of well data, local reservoir data, and offset well data, which were then used in an initial reservoir model. The initial reservoir simulation was run, and the pore-pressure distribution during production was generated, as shown in **Fig. 14**.

Using the process from beginning to end unfolded a great deal of potential that was overlooked on the offset wells. As can be seen in Fig.14, there is a region surrounding each fracture of similar pressure distribution. In trying to achieve a uniform pressure drop along the wellbore, an additional pressure differential between the fractures is needed. This amplifies the need for an engineering process to determine the necessary fracture density. It was apparent the well needed a higher fracture density, so the number of fractures was increased until the optimal number of fractures for both production and economics was achieved.

All of the offset wells had a variety of different completions and stimulation methods. With the use of this process, a more desirable fracture density was determined. Well 1 was completed with the designed fracture density and consequently performed better than those with a lower fracture density. The other wells (Wells 2 through 6) were all horizontal completions in the same reservoir, and the resulting cumulative volumes can be observed in **Fig. 15**.

CONCLUSION

The process described in this paper should help decrease the amount of time needed to fully exploit the potential of a reservoir. Stimulation optimization is an iterative process; the stimulation effectiveness should improve as the iterations increase.

The use of a reservoir simulator will help aid in decreasing the number of iterations needed to maximize the potential of a horizontal completion. Without a reservoir simulator, the same computations can still be performed manually using advanced variations of Darcy's Law or a variety of different types of curve analysis.

This paper assumes the hydraulic fractures being created are perpendicular to the wellbore. Even in advanced reservoir engineering, the dimensions of the hydraulic fracture being created are needed. Using fracture-mapping technologies can help decrease the amount of time refining HFMs in a variety of aspects.

The use of optimization type curves similar to Tinsley's production-increase curves can assist in giving a direction that is needed for improving the stimulation practices. The operator should pay close attention to the inputs because they could result in major errors if they are incorrect. Even when conventional production analyses is unavailable, the use of this process can aid in arriving at an improved stimulation treatment. For the stated case of Well 1, the goal for achieving the desired estimated recoverable reserves (ERR) was not only achieved, but it exceeded any and all the expectations.

REFERENCES

Love, T.G., McCarty, R.A., Surjaatmadja, J.B., Chambers, R.W., and Grundmann, S.R. 2001. Selectively Placing Many Fractures in Openhole Horizontal Wells Improves Production. *SPE Production & Facilities*. **16** (4): 219–224. DOI: 10.2118/74331-PA.

Soliman, M.Y. 1983. Modifications to Production Increase Calculations for a Hydraulically Fractured Well. *Journal of Petroleum Technology*. **35** (1): 170–172. DOI: 10.2118/9021-PA.

Soliman, M.Y., Hunt, J., and El Rabaa, A. 1990. Fracturing Aspects of Horizontal Wells. *Journal of Petroleum Technology*. **42** (8): 966–973. DOI: 10.2118/18542-PA.

Soliman, M.Y., Hunt, J.L., and Azari, M. 1996. Fracturing Horizontal Wells In Gas Reservoirs. Paper SPE 35260 presented at the Mid-Continent Gas Symposium, Amarillo, Texas, 28–30 April. DOI: 10.2118/35260-MS.

Surjaatmadja, J.B., Grundmann, S.R., McDaniel, B., Deeg, W.F.J., Brumley, J.L., and Swor, L.C. 1998. Hydrajet Fracturing: An Effective Method for Placing Many Fractures in Openhole Horizontal Wells. Paper SPE 48856 presented at the International Oil and Gas Conference and Exhibition in China, Beijing, China, 2–6 November. DOI: 10.2118/48856-MS.

Tinsley, J., Williams Jr., J.R., Tiner, R.L., and Malone, W.T. 1969. Vertical Fracture Height-Its Effect on Steady-State Production Increase. *Journal of Petroleum Technology*. **21** (5): 633–638. DOI: 10.2118/1900-PA.

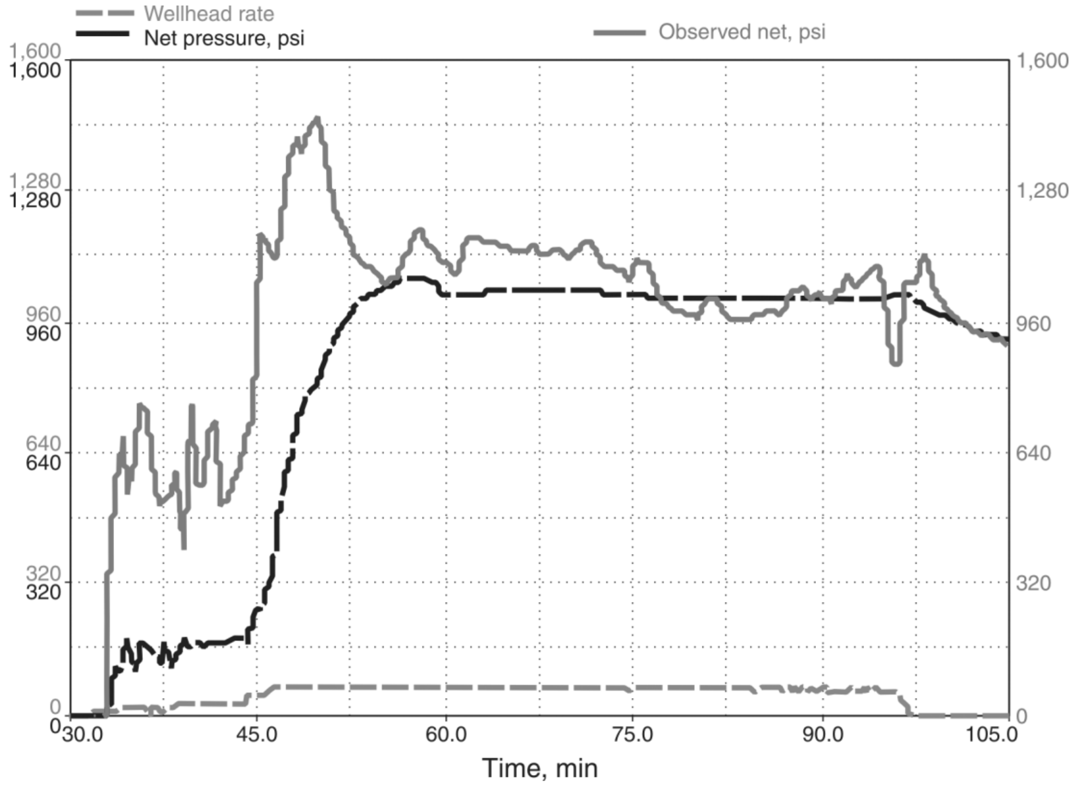

Figure 1—Net-pressure model—matching observed to modeled.

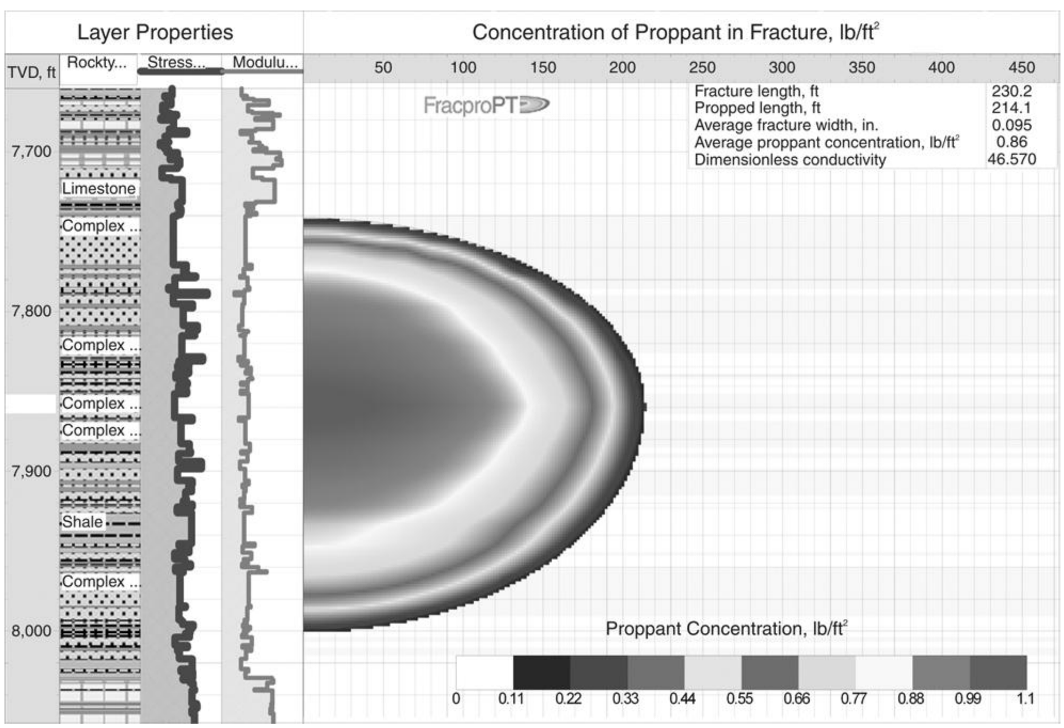

Figure 2—Hydraulic-fracture model.

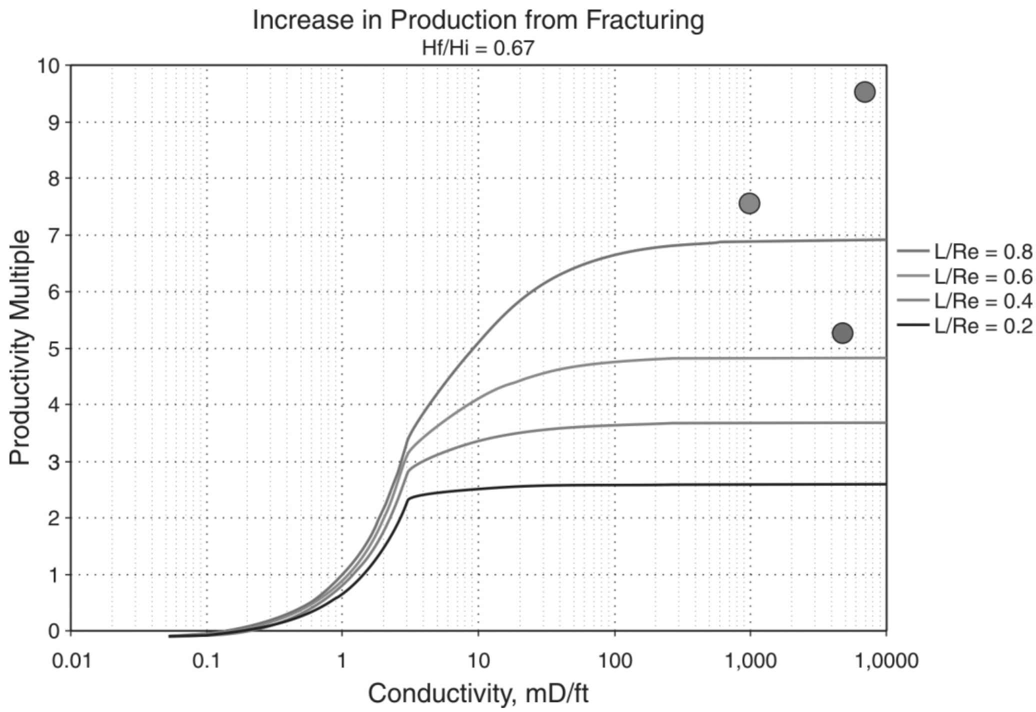

Figure 3—Production increase.

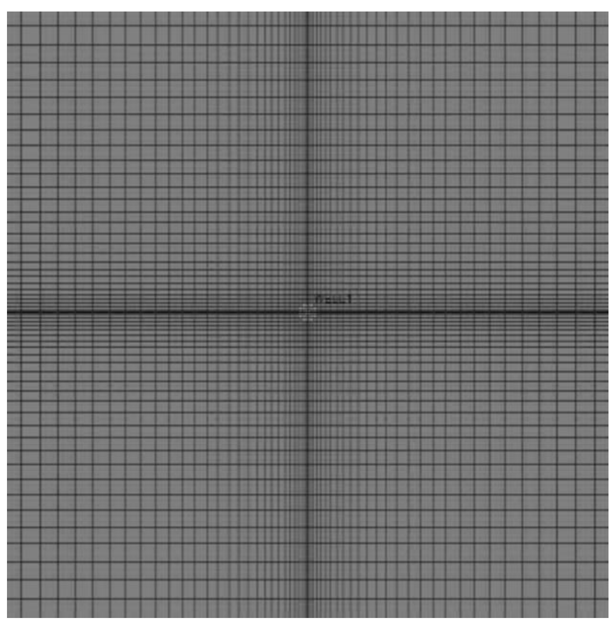

Figure 4—Drainage radius limitation at 0.1 mD.

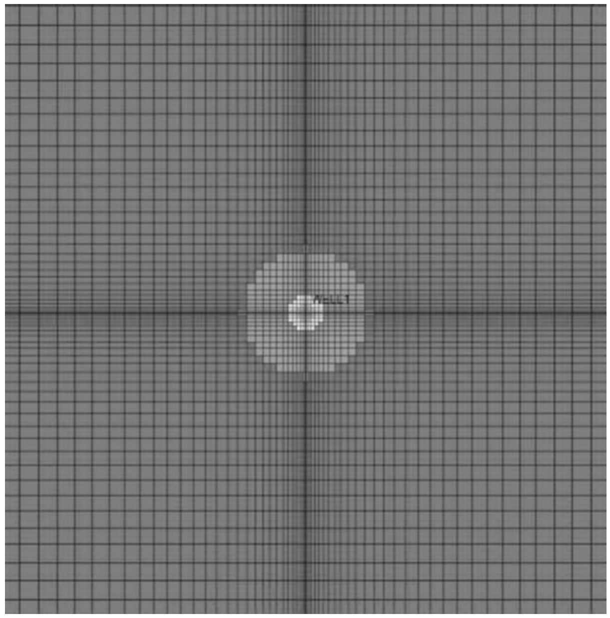

Figure 5—Drainage radius limitation at 10 mD.

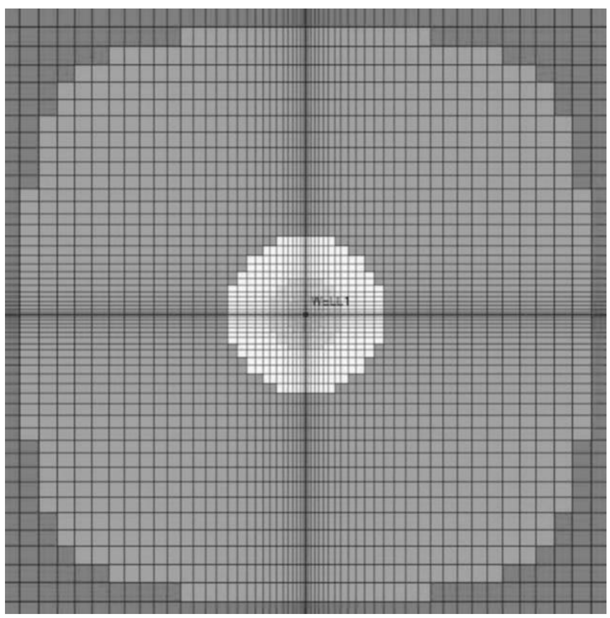

Figure 6—Drainage radius limitation at 1000 mD.

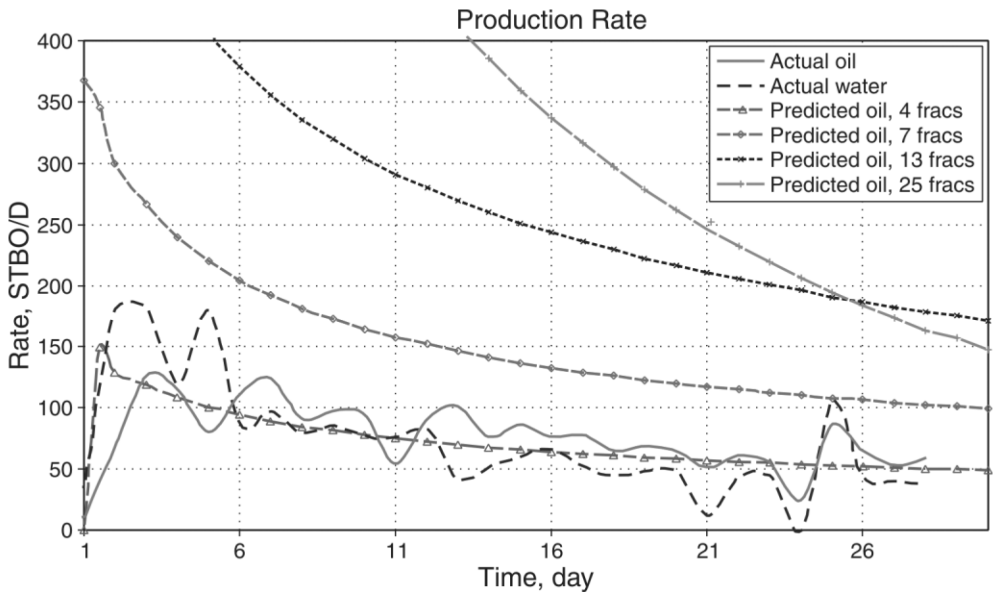

Figure 7— Reservoir simulator production match.

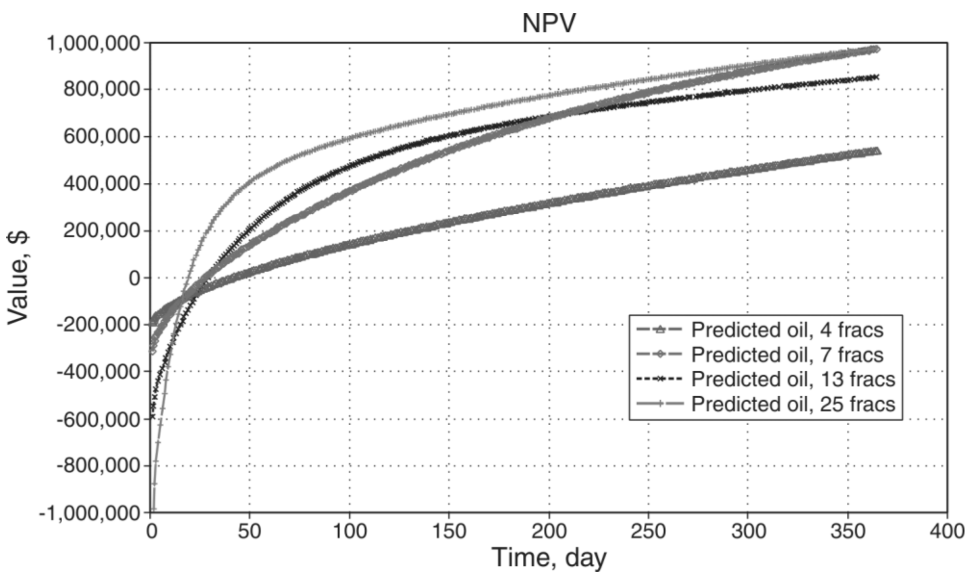

Figure 8—ROI vs. fracture density.

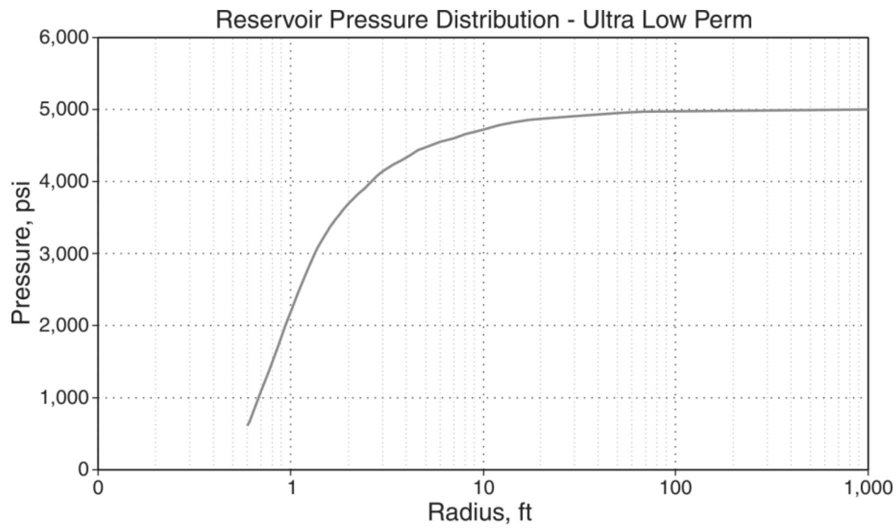

Figure 9—Alternative methods—fracture density.

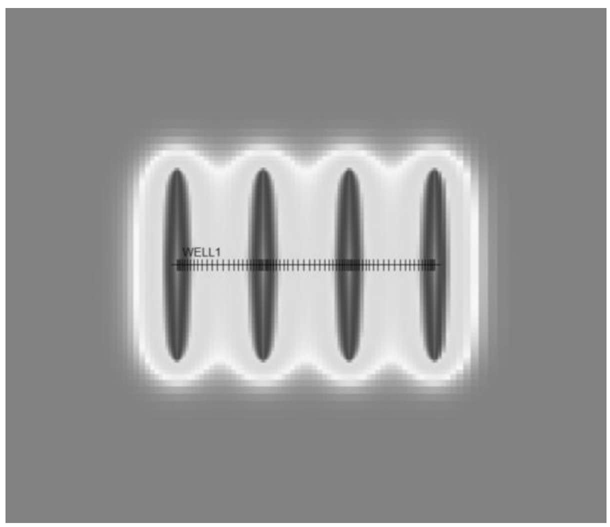

Figure 10—Reservoir-pressure distribution of four fractures.

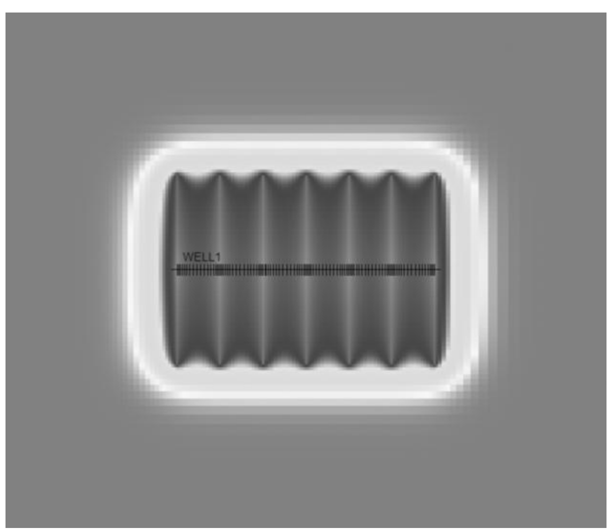

Figure 11—Reservoir-pressure distribution of seven fractures.

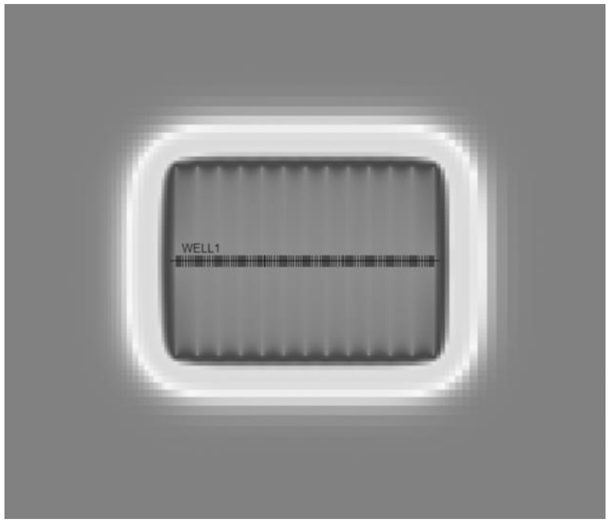

Figure 12—Reservoir-pressure distribution of 13 fractures.

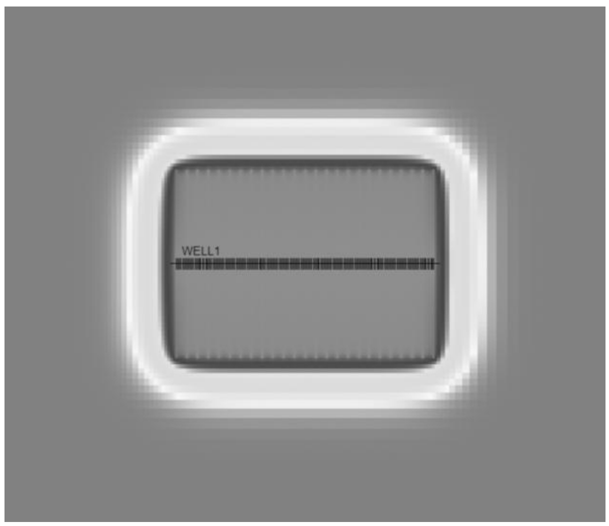

Figure 13—Reservoir-pressure distribution of 25 fractures.

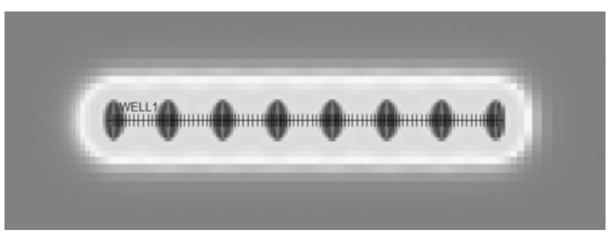

Figure 14—Case 2, Well 1 initial reservoir prediction.

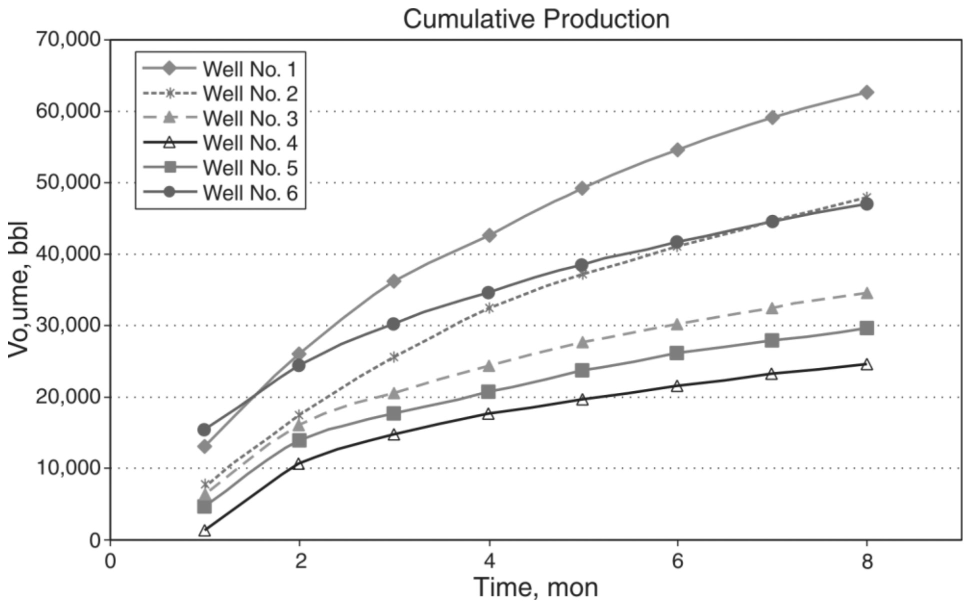

Figure 15—Well 1 performance.