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Application of Hydraulic Fractures in Openhole Horizontal Wells

P. D. Ellis, SPE, Golden Okie Associates, Inc., G. M. Kniffin, SPE, and J. D. Harkrider, SPE, Apex Petroleum Engineering

Abstract

This paper describes a process that has improved production, reduced costs, saved time, and dramatically improved the results of fracture stimulating low permeability horizontal wells. The use of both propped and acid fracture treatments will be described.

The process has been used for openhole completions aligned in the approximate direction of fracture propagation as well as for fractures transverse to the well bore. The technique has effectively eliminated well bore connectivity problems that had been observed in vertical completions and cased and cemented horizontal wells with transverse fractures.

The process has been used to increase production over 25 fold in a 30 year old field. It has also proven successful in a marginally economic field that had been completed using propped fractures in vertical wells.

The procedure employs a system of multiple, retrievable treating subs that are specifically tailored to a unique well bore configuration and allow treating the entire interval with a single stage. The treating subs are designed to distribute the treating fluid as desired along the length of the lateral. The process has been successfully used in over 100 wells and laterals in fields located in California, Illinois, New Mexico, Utah, and Texas.

Introduction

History of Horizontal Wells[1,2]. Horizontal and high angle wells have been envisioned and/or used for approximately 80 years. Patents were filed in the early 1920's in the United States, but the tools were never fully developed. Horizontal wells re-emerged in the 1940's and 50's, but were displaced when hydraulic fracturing was developed in the late 1940's and early 50's. Horizontal wells were used in the Soviet Union and China during the 1950's and 60's. A heightened interest in horizontal well resurfaced in the late 1970's due to the increased directional control developed for offshore drilling. By 1985 further advances in horizontal drilling techniques and production response led to a boom in horizontal wells.

Well Paths[1]. Many different well paths are considered "horizontal" besides a flat path. Common trajectories include inclined, both up and down, wavy or undulating, multilevel, and multilateral, or depending on the application very complicated. Fig. 1 shows some of the more common well paths.

Common Uses[1,2,3]. Horizontal wells increase production by contacting more reservoir rock; intersecting natural fractures; reducing gas or water coning at a given production rate or drawdown; improving sweep efficiency in secondary and tertiary recovery projects; and improving gravity drainage in low pressure reservoirs. Ideally, the horizontal well should be completed openhole to take full advantage of the increased reservoir contact. This is not always possible due to wellbore stability problems or undesired fluid entry.

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Unstimulated Wells[1,3]. Horizontal wells are cost effective where the reservoir permeability is sufficient, damage is not excessive, or sufficient natural fractures are encountered to produce economically. Completions are relatively simple when these key parameters are encountered and stimulation, isolation of undesired gas/water, or wellbore stability is not a problem. However, when these problems exist, the complexity of the horizontal completion increases dramatically. Isolation requires that additional hardware such as external casing packers, scab liners, screens, slotted liners, etc. be used in an effort to eliminate the unwanted reservoir problem.

Typically, the most common method of isolation is cementing casing in the horizontal. Unfortunately, this isolates not only the problem but also the reservoir from the wellbore. Though selective perforating may re-establish communication with the reservoir, restoring production usually is more difficult. If the matrix permeability is sufficient, productivity may not be lost. However, if the production comes primarily from natural fractures, perforating into the natural fractures to restore production is highly unlikely. Regardless of the perforating technique, once cemented, stimulating the lateral becomes the dominant variable in a horizontal well completion.

Matrix Stimulation[1,3]. While many wells can be completed with no stimulation, the extended time required to drill a horizontal well of several thousand feet compared to drilling a vertical well through the comparatively thin pay zone can result in damage that must be removed in order to have an economic completion. Aside from the issue of damage identification and the subsequent fluid selection, the critical operational issue is effectively distributing the cleanup fluid along the entire horizontal section.

Pump time for a matrix stimulation of a horizontal well can be ten times or more than a vertical well depending on the ratio of lateral length to vertical pay. A vertical well with 100 ft of pay zone treated using 100 gal/ft at one-half bpm requires approximately 8 hours pumping time. By analogy, a horizontal well with 1,000 ft of section would require over 80 hours of pumping to give an equivalent treatment if the rate could not be increased. Fortunately, the increased length allows the rate to be increased depending on the ratio of horizontal to vertical permeability. For a horizontal to vertical permeability ratio of ten, the rate could be tripled for the horizontal well reducing the time to approximately 24 hours.

The two most common placement methods for matrix stimulation are bullheading and moving tubing/coiled tubing through the horizontal wellbore. While treating the entire section is important in a vertical well, it is essential in horizontal completions. Thus, diversion, either mechanical or chemical, is required for matrix stimulations. Straddle packers or packer/retrievable bridge plug assemblies conveyed by tubing or coil tubing can provide effective mechanical isolation to a portion of the horizontal. Though limited in openhole completions, this type of mechanical isolation is most effective in cased, cemented, and perforated completions. Chemical diverters such as benzoic acid flakes, rock salt, wax beads, foams, gels, etc. are often used in openhole and slotted liner completions with marginal effectiveness. However whether mechanical or chemical diversion is used, the completion time is significantly increased. Multiple sets of packers, packer failures, tubing or coiled tubing movement, reduced injection rates required when using chemical diverters or small diameter tubing, all exponentially increase the time required to matrix stimulate the horizontal well. To eliminate these diversion issues and costs, many operators employ bullheading techniques to stimulate the horizontal. Though cost effective, coverage of the lateral is sacrificed and subsequent production results can be disappointing.

Hydraulic Fractures[1,2,3,4]. Though advances in drilling systems made horizontal wells attractive by the mid-80's, horizontal well stimulation was not an unqualified success. Major issues included wellbore stability in uncased horizontals, cement bond quality when cementing horizontal wellbores, cost effective methods to isolate individual stages, unique stress fields induced around the borehole causing excess skin/pressure signatures, and the preferred direction of fracture propagation relative to wellbore orientation (longitudinal or transverse).

Treatment Type. These issues continue being important considerations in completing horizontal wellbores using hydraulic fracture treatments today. If the horizontal is stimulated with either acid or water fracture treatments, methods employed in matrix stimulation are applicable including a heel and toe variation using tubing run to the end of the lateral.

For propped fracture treatments, however, pipe is usually cemented and perforated to perform the fracture treatment. Concerns about wellbore stability, isolation between stages, and fishing stuck pipe in an openhole environment are the primary reasons for cementing casing in the horizontal wellbore. When multiple transverse fractures are placed, common practice is to pump multiple stages with mechanical isolation between stages[5]. Also, multiple stages with mechanical isolation have been used in cemented and perforated wells for longitudinal fractures[6].

In addition, when pumping a propped fracture treatment in a cased, cemented, and perforated horizontal well, high breakdown and treating pressures have been reported and are prone to premature screenouts if not mitigated. These problems have generally been attributed to tortuosity (turning of the fracture), multiple competing fractures, or a poor cement job. Common techniques to minimize the near-wellbore effects include pumping proppant slugs, breaking down the formation with cross-linked gel, and extreme overbalanced perforating prior to pumping the main fracture treatment[5,7,8].

Within the past few years, a new emphasis has been placed on using propped fractures in the openhole environment. Several proposals have been put forward in addition to the process discussed here.

Longitudinal or Transverse Fractures[2,3,4,9]. The orientation of the induced fracture relative to the wellbore, i.e. longitudinal or transverse, is also of great importance in horizontal completions. To illustrate the concept, Fig. 2 shows a longitudinal fracture and multiple transverse fractures for a horizontal well.

Many reservoir simulation studies comparing the predicted response of a vertical fractured well to a horizontal well with either a longitudinal fracture or multiple transverse fractures have been performed. In most comparisons, the vertical well is assumed to have a fracture half length equal to one-half the horizontal well length. With this assumption, it is difficult to economically justify drilling a horizontal well having a longitudinal fracture orientation unless the vertical well has a finite conductivity fracture. Similarly, reservoir simulation studies have shown that multiple transverse fractures are required to justify the increased cost of drilling the horizontal well and to offset the choke effects caused by the limited contact of the fracture with the wellbore and/or re-orientation of the fracture away from the wellbore.

A vertical well with an infinitely conductive, 1,000 ft half length fracture would, therefore, be more economic than a 2,000 ft horizontal well with a full longitudinal fracture according to these simulations. Unfortunately, production modeling and pressure transient testing of vertical fractured wells have not consistently confirmed the ability to achieve an effective fracture half length of 1,000 ft. Actual results are often in the 200 ft to 300 ft range and occasionally in the 50 ft fracture half length range. Reasons for the shorter effective fracture length are documented in the literature but could include any or all of the following reasons: height growth out of the designed interval; multiple fractures either from a single set of perforations or from multiple sets of perforations that fail to connect together; or residual gel damage. Thus, effective completion of a 2,000 ft horizontal well with a longitudinal fracture could in fact be more economical than a vertical fractured well.

To illustrate this point with a simplistic comparison, consider the fracture area within the pay zone for the vertical well assuming 100 ft of vertical section and a 250 ft effective fracture half length compared to a 2,000 ft horizontal well with a 50 ft (vertically) fracture half length. For the vertical well, the cross-sectional fracture area (one face only) is 2x250x100 or 50,000 ft^2. For the horizontal well, the area is 2x2000x50 or 200,000 ft^2. Thus, it would take four vertical fractured wells to yield the same fracture area as the one horizontal well. Assuming that transverse fractures would be equivalent in length to the vertical well fracture and ignoring the choke effects for limited wellbore contact and/or fracture re-orientation, it would also take four transverse fractures to equal the area of the single longitudinal fracture. To more accurately assess whether the longitudinal fracture or multiple transverse fractures would be more economic requires a detailed reservoir simulation comparing these two scenarios.

It should also be noted that, for the horizontal well with a longitudinal fracture, only one-fifth of the fracture conductivity of the vertical well is required to achieve an infinitely conductive fracture due to the shorter fracture length required to reach the upper and lower boundaries of the

Experiences with Propped Fractures in Horizontal Wells

By the mid 1990's, horizontal wells were being used successfully in a number of areas. The Austin Chalk of Texas was often touted as example of successful wells as were wells in the Dan Field of the North Sea, to name but two.

With these successes, some in the industry began to believe that horizontal wells could cure all our reservoir quality ills and possibly eliminate the need for hydraulic fractures in low permeability formations, particularly if natural fractures could be intersected. This was not to be in all cases however. Many wells that were drilled in anticipation of encountering natural fractures failed to do so. Then came the question: "how can this well be salvaged?" For these low permeability wells, the only option besides abandonment was a hydraulic fracture treatment. Then came the problem: "how can this well be effectively stimulated?"

Table 1 lists the average reservoir properties for the four fields to be discussed in this presentation.

Near-Wellbore Connection Problems. Even in areas, such as the Dan Field, where successful application of propped hydraulic fractures to horizontal wells has been documented, mitigating near-wellbore connection problems was essential for effective stimulation. Completion procedures such as acid breakdowns, high viscosity slugs, proppant slugs and overbalanced perforating have been implemented in vertical wells to successfully address the near-wellbore connection problem[5,6,7]. Three projects are discussed to illustrate the application of these procedures in horizontal completions, with varying degrees of success.

The first case study is a newly drilled gas well in the Red Oak formation of southeast Oklahoma. The second case study is a re-entry project of three oil wells in the Gallup formation of northwest New Mexico. The third case study was a five well project in the Monterey formation in Kern County, California. Table 1 lists the average reservoir properties of the Red Oak, Gallup, and Monterey formations. Vertical wells in all three of these formations require propped fractures to establish production. Both the Red Oak and Gallup horizontals were completed using generally accepted procedures while the Monterey wells used the patent pending process.

Red Oak. In the Red Oak horizontal, the geologic expectation was to cross natural fractures and yield economic production without fracture stimulation. Natural fractures were not encountered and production was uneconomic from the openhole. Thus, the contingency plan to set and cement a liner to pump multiple transverse fractures was implemented.

After cementing the liner, short intervals (2 to 3 ft) of highest bond were selected for perforating to reduce the possibility of developing multiple competing fractures within the interval. Tubing-conveyed perforating guns with high shot density and large diameter holes were used.

A perforation breakdown test using linear gel was pumped to determine the extent of the near-wellbore or fracture/wellbore connectivity problems using gel. Initially, the formation could not be broken down as pressures exceeded the anticipated 5,000 psi, which is the typical treating pressure for vertical wells. Tubing was tied into the liner and the formation finally broke down at a pressure in excess of 9,000 psi. Two proppant slugs were pumped to condition the wellbore to fracture connectivity, followed by the nitrogen foamed fracture treatment. Screenout occurred with approximately 20% of the designed proppant volume placed. Subsequently, the horizontal was re-fractured using a borate cross-linked gel. Approximately 30% of the designed proppant volume was pumped prior to flushing due to high treating pressures.

For the second stage, proppant slugs in both linear and borate cross-linked gels were planned before attempting the main fracture treatment. These procedures were designed to mitigate the wellbore to fracture connectivity problem. Though the subsequent treating pressures were greatly reduced as a result, and the propped fracture treatment successfully placed 6 to 8 ppg, the mitigating procedure was costly, requiring several additional days of rig and pumping time.

For the third stage, extreme overbalanced perforating (EOB) was used in an attempt to reduce the near-wellbore problems and minimize the time and fluid volumes required to condition the near-wellbore connection. The near-wellbore problem was significantly reduced using EOB as the breakdown and treating pressures were the lowest of the three stages. The improvement was dramatic as a lower viscosity CO_2 foam system successfully placed 10 ppg in the fracture. Though EOB is an effective technique for mitigating the near-wellbore connectivity problem, it potentially increases the far-field fracture complexity which in itself may contribute to premature screenouts.

Gallup. In the second case study, three horizontal re-entries were drilled to intersect natural fractures with the intention of eliminating the need for fracture stimulation. Again, no natural fractures were encountered. Two of the wells were acid stimulated unsuccessfully in the openhole as formation stability problems arose after the acid treatments. In the third re-entry, a liner was set, cemented, and perforated. Subsequently two transverse fracture treatments were pumped.

As this was a re-entry, a small 3-1/2 inch liner was set. Coiled tubing was used for logging, perforating, cleanout, and setting bridge plugs for isolation between fracture treatments. Short intervals were again perforated, but EOB could not be used due to the limitations of the available coiled tubing. Similar to the mechanisms observed in the Red Oak horizontal, wellbore to fracture communication was impaired as breakdown pressures and near-wellbore effects were high.

Proppant slugs reduced the near-wellbore problems, but the first fracture treatment screened out when 6 ppg proppant laden fluid hit the formation. Approximately 56% of the designed volume was placed in the fracture. For the second stage, identifying the near-wellbore connection problem early resulted in using an acid soak on the perforations and incorporating proppant slugs during the treatment. These mitigating procedures further reduced the treating pressure and proppant concentrations up to 6 ppg were successfully placed.

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New Approach Required. In both of these projects, the costs and subsequent production results raised concerns about the viability of horizontal wells in tight formations. A different approach was required to make a successful well or the application of horizontal wells in tight formations would be discontinued. Development of the process will be discussed after the dramatic reduction of near-wellbore effects is shown with the Monterey horizontals.

Monterey. This horizontal project was initiated because of marginal economics from an exploration and development package of the Monterey shale. Six vertical wells had been drilled and fracture stimulated with a maximum proppant concentration of less than 8 ppg. Near-wellbore problems were encountered in the vertical wells, and in some cases, resulted in premature screenouts with only 25% of the designed proppant volume placed. To illustrate the near-wellbore fracture complexity, Fig. 3 shows a pump-in step down test on well V-1. Based on the annular/dead string pressure, approximately 1,200 psi of near-wellbore pressure effects were measured at 18 bpm. Fig. 4 demonstrates the severe nature of these wellbore to fracture connection problems as the well screens out as when a one-half ppg proppant slug reaches the formation. Similar near-wellbore problems were observed in well V-2 although no annular pressure could be measured. Fig. 5 shows the main fracture treatment for well V-2. Notice the pressure inflection as 6 ppg first enters the perforations and suggests proppant was bridging asymmetrically. The treatment eventually screens out due in part to the poor near-wellbore connection.

In order to improve the economics of this field, a horizontal well was proposed. The initial plan was to cement a liner and to pump multiple transverse fractures. Based on the high near-wellbore problems seen in the Red Oak and Gallup horizontal wells, the successes completing the Devonian wells noted below, and the near-wellbore problems of the offsetting vertical wells, the plan was significantly revised. The well path was re-aligned to the anticipated fracture direction and the completion was changed to an openhole, single stage fracture stimulation using the process developed. Fig. 6 shows a pump-in step down test for the first horizontal well. A dramatic improvement in the wellbore to

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