Reservoir and Completion Considerations for the Refracturing of Horizontal Wells

R. D. Barree, Barree & Associates; **J. L. Miskimins,** Colorado School of Mines; and
K. J. Svatek, Barree & Associates

Summary

Horizontal-well developments, focused on transverse hydraulic-fracture stimulation, have evolved rapidly during the past decade. Many of these completions may have missed or bypassed significant reserves that were intended to be produced from the well. This paper discusses the potential reasons for these inefficient completions, candidate selection for refracturing, and the impacts of offset depletion/infill wells on refracturing.

Rate-transient post-treatment stimulation analysis is a powerful tool that can help determine whether and when a horizontal well is receptive to refracturing. Such analysis can help determine whether a well is underperforming, and if that underperformance is caused by an inefficient completion or by reservoir conditions. The paper discusses the importance of appropriate well conditioning/unloading before determining if a refracturing may or may not be successful. The impacts of "bashing" into offset depletion during refracturing treatments are also discussed, along with appropriate design considerations to minimize such impacts.

Refracturing can be an important tool to the industry, and it deserves the attention that it is currently receiving. However, the success of such treatments is not guaranteed in every well, and the criteria for candidate selection should be a top focus when evaluating such a program.

Introduction

Horizontal-well developments with transverse hydraulic-fracture stimulation have evolved rapidly during the past decade. Many early wells relied on cemented-liner completions with widely spaced perforation clusters, uncemented liners with relatively few fracture-initiation sites, or fully openhole completions. These early completions may have missed or bypassed significant reserves. In other cases, wells may not have produced at their potential, because of loading, well-terrain effects ("porpoising"), or mechanical damage to the completion. For a variety of reasons, production declines observed in horizontal wells are very high, leading to unacceptably low producing rates after a few years of production. **Figs. 1 and 2** show observed decline rates for horizontal oil plays and gas plays as a function of time. These high declines may be caused by inefficient completions or simply by reservoir conditions. No matter which is the cause—or perhaps it is a combination of completions and reservoir conditions—it is obvious that declines are significant in the first 5 years of a given well's life.

The combination of high decline rates and current low oil prices has led to the anticipation that the refracturing of existing horizontal wells may add new life and economic value, at a much lower capital investment than the drilling and completing of new wells. However, for refracturing to be successful, it is necessary to characterize the current production profile of the candidate well, to identify the reason or reasons for the low production rate or rapid decline, and to design a stimulation treatment that will overcome any associated limitations on production to add value. Just pumping a refracturing treatment into an existing well and hoping for an economically valuable result is not a wise, or usually successful, course of action.

In general, refracturing can be economically successful if one of two scenarios is attempted to be resolved. First, the treatment must contact a new reservoir that has not been previously drained. To accomplish this, the refracturing treatment must (1) break down portions of the wellbore that have not been previously effectively stimulated; (2) allow for production from previous fractures that are plugged and nonproductive; (3) increase the effective fracture height to cover additional net-pay that can contribute to production; or (4) cause reorientation of the fractures so that drainage area and aspect ratio are altered. The second scenario is one with which a person can refracture a well to replace near-well conductivity or to repair damage to the fracture proppant pack. Unless the reservoir deliverability is there to support the replaced conductivity, this route will usually result in a short transient spike in production with a rapid return to the previous decline trend.

No matter which scenario is pursued, correctly identifying the reasons for substandard performance is necessary (Vincent 2010). After these reasons are verified and a refracturing treatment can address one of these scenarios, refracturing can be successfully applied.

Candidate Selection

The selection of an appropriate candidate for refracturing starts with an analysis of the previous completion-and-production history of the well. In cases of inefficient initial stimulation, with too few or too widely spaced fractures, the use of radioactive tracer logs or nonradioactive tracer in the initial completion may make candidate selection simple (Leonard et al. 2016). If the logs show large sections of the well that were not stimulated, then targets for new fracture-entry points can be identified, as shown in **Fig. 3.** In cases in which tracers were not run in the initial completions, the analysis must be based on the interpretation of production data.

Such a production analysis should determine how much of the lateral is contributing to production, the drainage area, and the shape (i.e., aspect ratio) of the drainage area that has been affected by the past-production transients. Various levels of diagnosis of field data may be applied, with rate-transient analysis of the entire production history likely providing the most information from a flowing production standpoint (Ilk et al. 2010). Wellbore diagnostics such as temperature profiles (distributed temperature sensor), production profiles (spinner, gradiomanometer, and temperature), downhole video surveillance, or tracer-injection profiles may also be used to determine which fractures or perforation clusters are contributing to production. If available, such diagnostics can also be used to determine what the initial treatments looked like and if there were any issues during the initial treatment that might account for the well's current behavior (such as the leaking-bridge plugs shown in **Fig. 4**). The analysis of historic production declines from vertical wells, with a single effective fracture, can provide useful information on the system transmissibility and the drainage area and aspect ratio that can be contacted.

Single-Plot Analysis

One of the simplest, and least costly, techniques for candidate identification is a simple log-log plot of production rate vs. time, assuming the well has been operated during most of its life at a

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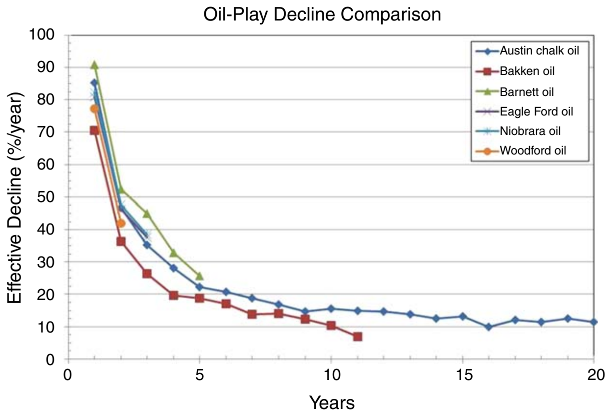

Fig. 1—Effective decline rates for horizontal wells in various unconventional oil reservoirs [Data provided by S. A. Cox and R. P. Sutton, unpublished].

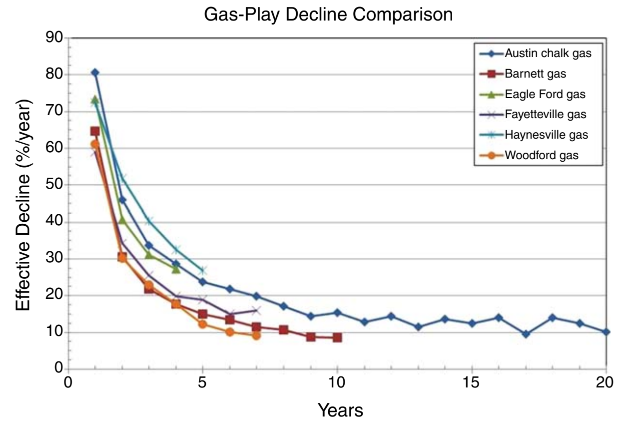

Fig. 2—Effective decline rates for horizontal wells in various unconventional gas reservoirs [Data provided by S. A. Cox and R. P. Sutton, unpublished].

fairly constant pressure. **Fig. 5** shows an example of this plot for a Bakken oil well [From S. Cox's SPE Distinguished Lecturer presentation, 2005].

Although the well is in transient flow, the data should fall on an approximate one-half slope. When the trend steepens to approach a unit slope, the well is in boundary-influenced flow. The boundary can be a geologic limit to the drainage area or the no-flow boundary set up by pressure interference with an offset well. After the production trend reaches the unit slope, the well is in volumetric depletion, and the ultimate recovery of the well, for its current completion, is defined. For a refracturing treatment to be successful in this scenario, it must increase the volume of reservoir attached to the well; otherwise, the risk is that the treatment will just result in a potential acceleration of the ultimate recovery.

Another analysis technique is the application of the so-called Wattenbarger or specialized linear flow plot (Arevalo-Villagran et al. 2001). This plot, shown in **Fig. 6,** has an inverse productivity index (PI) (DP/Q) on the *y*-axis and a square-root of the equivalent material-balance flow time on the *x*-axis. A straight line on this plot theoretically defines a linear flow regime, but which linear flow regime it is remains a discussion point in the industry. If the input data to the plot are constrained by a system-permeability estimate from a properly interpreted diagnostic injection test (DFIT), then the start and end of the straight-line portion of the plot can define the effective fracture spacing, well spacing, and drainage area of each fracture (Barree et al. 2015). The slope of the straight line is proportional to the overall flow capacity of the well, but by itself, it does not differentiate between good reservoir $k{\cdot}h$ and stimulation efficiency.

In the example of Fig. 6, the start of the straight line indicates the fracture spacing, or time to interference of the production pressure transient between adjacent transverse fractures. The end of the straight line indicates the time to interference with the drainage boundary or offset well. The data for this example were generated with a 3D numerical reservoir simulator with input reservoir properties and fracture-geometry information shown in the yellow-inset box. The time to each interference is related to distance through the transient radius of an investigation equation.

The lack of a measured and constrained system permeability can lead to the misinterpretation of the results shown in Fig. 6.

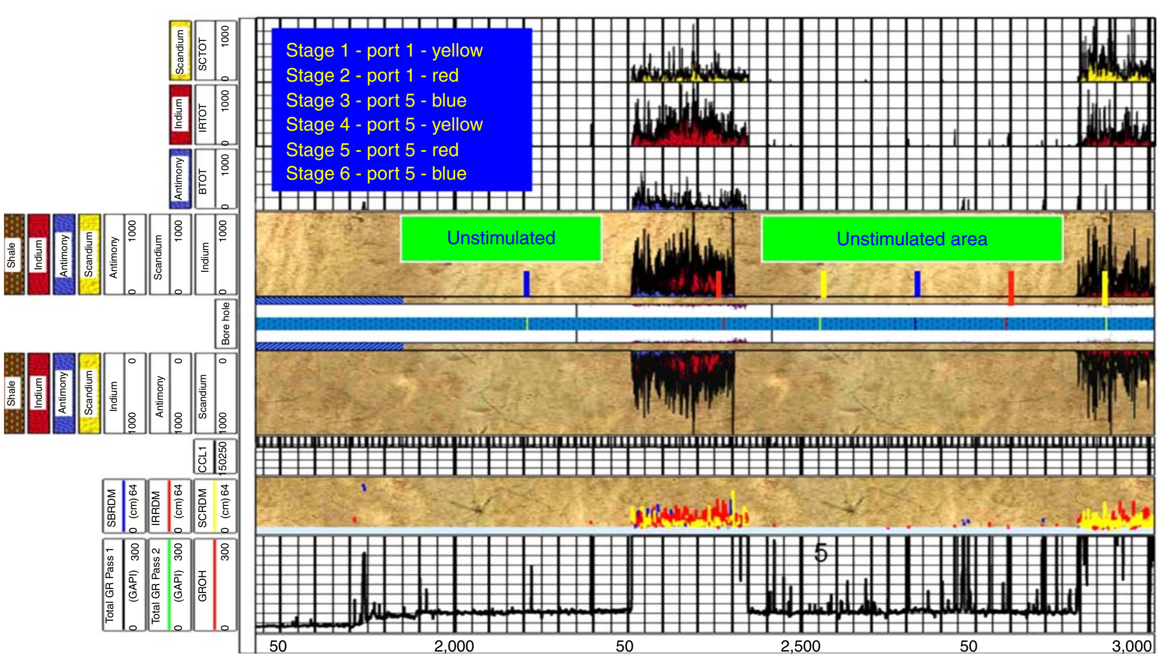

Fig. 3—Unstimulated areas in a horizontal wellbore determined by the use of radioactive tracers (lateral section of the well is ≈1000 m to ≈2000 m). Six stages (noted by the blue, red, and yellow bars) were attempted with an openhole packer system with sliding sleeves. It is unclear what caused the treatments to behave this way, but the tracer results show that large sections of the well were not treated (courtesy of Protechnics).

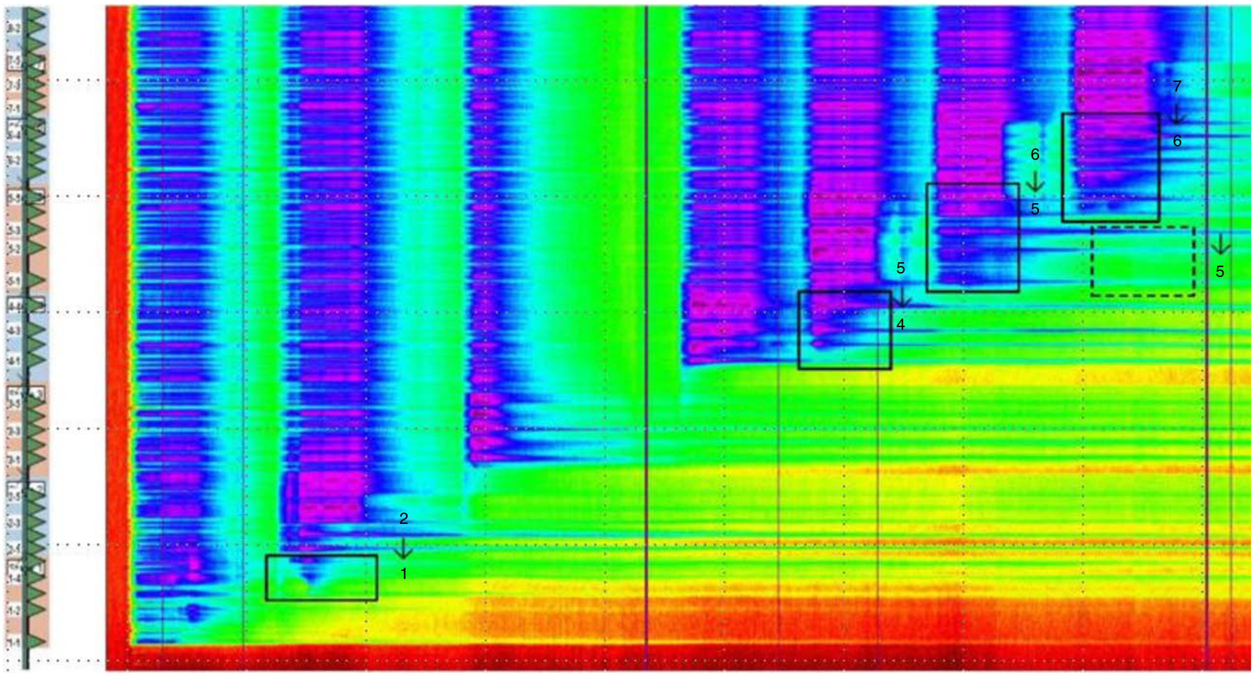

Fig. 4—DTS profile showing stage-to-stage communication. Seven stages are shown to the left of the figure with the perforation clusters identified by the green triangles and each stage distinguished by alternating blue and pink intervals. Communication between stages is indicated by the black boxes that note which stage leaked (top number) into which stage (bottom number). In the case of Stage 7, it leaked into both Stage 6 and Stage 5. From Wheaton et al. (2016).

Likely, the most common misapplication is that crushed core permeability represents the system flow capacity. Such extremely low-permeability values cause the interpretation of the plot to lead to very long productive fractures with large effective spacing or excessive time for fracture interference. This false interpretation then leads to the assumption that refracturing with a higher density of entry points will be sufficient to increase recovery and to justify the refracturing treatment. With a correct permeability value, it may become apparent that the fractures are interfering, with overlapping drainage areas, and the entire reservoir volume around the well is being effectively drained. In this case, a refracturing to achieve higher fracture density will not contact additional reservoir volume and is not economically advisable.

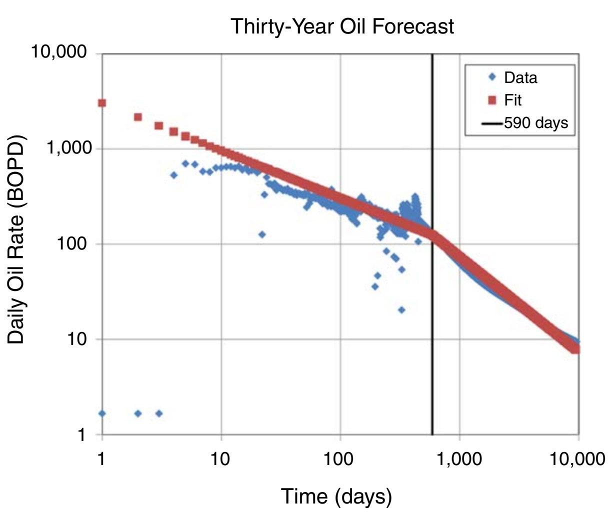

Fig. 5—Log-log plot of rate/time for oil or gas well to identify the start of boundary-influenced flow. While in transient flow, the data (in blue) exhibit a slope of one-half (left of the figure). After the data reach a unit slope (right of the figure), the well is in boundary-dominated flow. This slope change of one-half to unity occurs at approximately 590 days for this Bakken well.

Fig. 7 illustrates this potential problem. The black lines represent a horizontal well pattern with fixed well spacing. The dashed red lines represent the created hydraulic-fracture lengths from the original treatment. As is common, these fractures would hit, or "bash," offset wells in the pattern, and may have adverse effects on cleanup or production. With a single well drilled to hold acreage, the drainage area affected by each fracture may approach the pink ellipse, with the disturbed rock around each created fracture generating an enhanced permeability region (EPR), or producing stimulated reservoir volume (SRV) (not to be confused with a microseismic cloud "SRV"). The production analysis of single wells in a section may lead to an overestimation of the drainage area that can be contacted by each well, after the pattern is drilled.

After the well is put on production, the fractures close and yield an effective flowing length represented by the solid red lines. The pressure transient induced by production from each contributing fracture moves outward from each fracture face, and is controlled by the diffusivity of the reservoir. When the pressure transients from adjacent fractures meet at the midpoint between the fractures, a no-flow, or constant-potential barrier, is formed. Similarly, the pressure transients from offset wells will form no-flow barriers, given sufficient production time. In such a scenario, the blue boxes represent the total reservoir drainage volume that can be affected by each fracture. The distances to the boundaries are shown by the ends of the straight line in the linear flow plot demonstrated by Fig. 6. If the drainage volume contributing to production accounts for the entire drainage area intersected by the well, then refracturing will likely be unsuccessful because no additional reservoir volume can be added to the well. The only way that more reservoir volume can be added would be to increase the effective fracture height and any associated net-pay thickness contacted. If the original fracture jobs were slickwater treatments, this may be achieved through crosslinked gel or hybrid-refracturing designs that might possibly generate more height than the slickwater treatment (Palisch et al. 2008).

Rate-Transient Assessment

The most complete method to analyze well performance and to identify refracturing candidates is a thorough rate-transient analysis of the full production history of the well. This requires oil, gas,

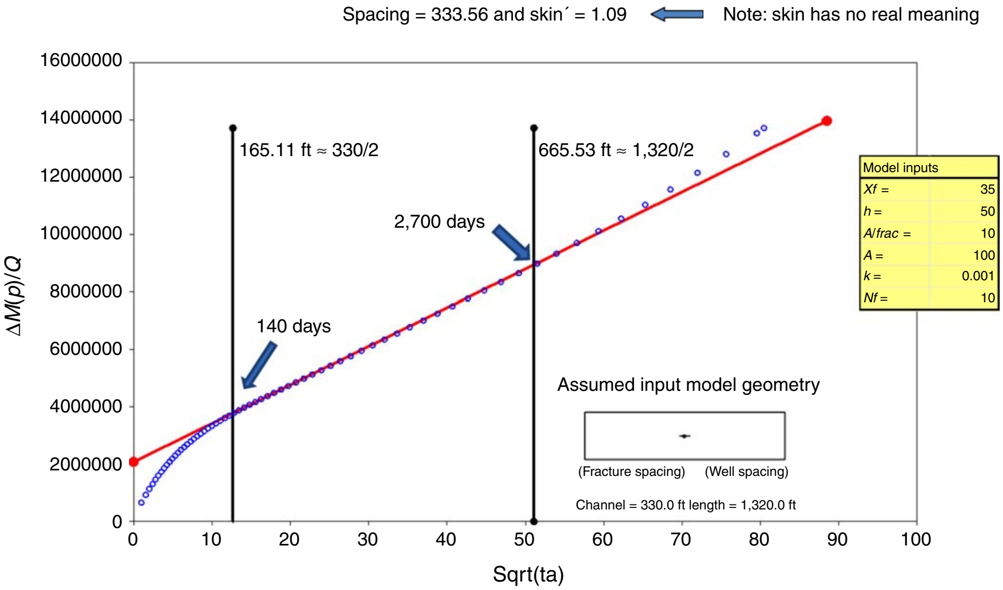

Fig. 6—Specialized linear flow plot for 10 fractures (*Nf*) on a 5,000-ft horizontal well. The model inputs include flowing fracture half-length of 35 ft (*Xf*), drainage height of 50 ft (*h*), drainage area of 10 acres per fracture (*A/frac*), total drainage area of 100 acres (*A*), and permeability of 0.001 md (*k*) (from Barree et al. 2015).

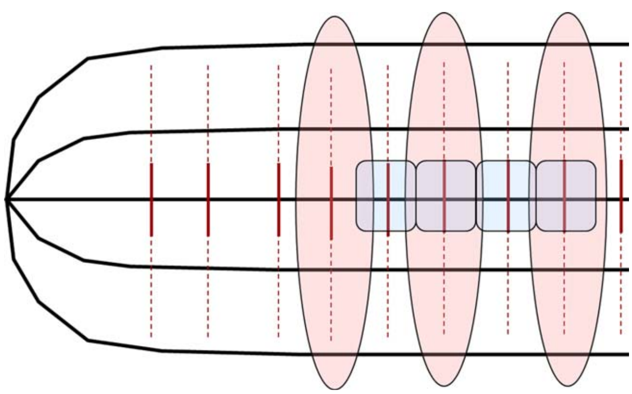

Fig. 7—Drainage pattern established by pattern drilling of horizontal wells. The black lines represent the horizontal well sections, the red dashed lines the hydraulic half-lengths present while pumping a treatment (and can lead to "bashing"), and the solid red lines represent the effective production length.

and water rates (preferably daily, but monthly can be used if the well history is long enough), and some estimate of flowing pressure through time. If the well is aided by artificial lift, some idea of the standing-fluid level or pumped-off condition of the well is required to estimate flowing bottomhole pressure.

This method involves converting the raw pressure/rate/time data to dimensionless time and dimensionless pressure and matching to a type curve. A typical Agarwal-Gardner (Agarwal et al. 1999) type curve for a fractured well is shown in **Fig. 8.** The early-time bilinear and linear flow regimes are usually associated with the effective fracture length. If the type curve does not show linear behavior at early time, it may indicate very poor effective fracture length (by showing early pseudoradial flow) or damage, if the slope of the dimensionless pressure curve is negative. Either of these cases could indicate that refracturing would be beneficial.

After the pressure transient moves far enough from the fracture face, or set of fractures in the case of a horizontal well, there may be a pseudoradial flow regime. Data from this flow period can be used to determine reservoir flow capacity ($k{\cdot}h$), independently of fracture-effective length. Fracture length is determined from the duration of the linear flow period after the reservoir flow capacity

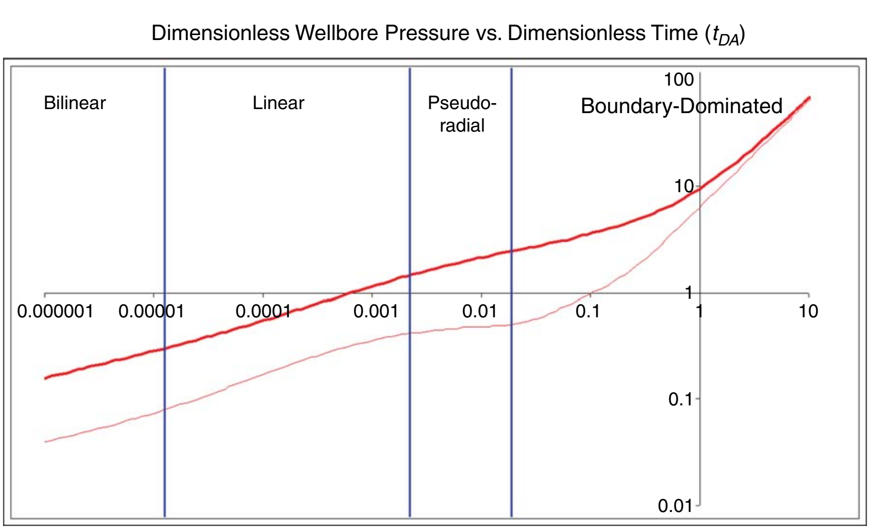

Fig. 8—Typical Agarwal-Gardner type-curve for a fractured well showing various flow regimes.

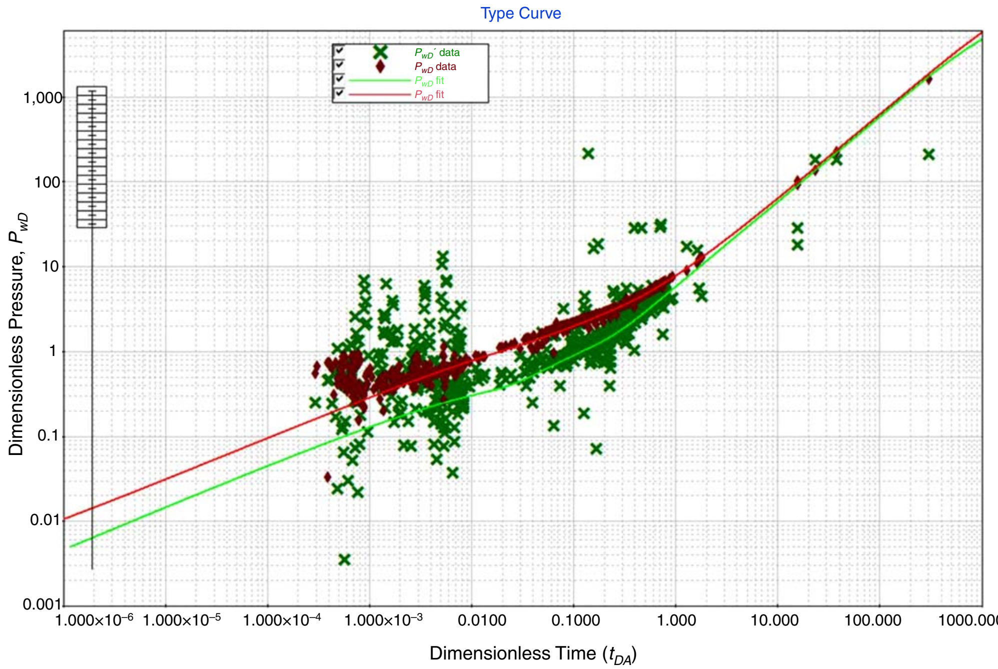

Fig. 9—Type-curve model for a horizontal well with 16 fracturing stages showing incomplete effective drainage of the lateral length. The data are shown by each green X and red diamonds. The type-curve match is shown by the solid green and red lines. The schematic to the left of the figure indicates, to scale, the length of the wellbore and the amount of the wellbore that exhibits contributing production, which, in this case, is approximately 30% of the wellbore length.

is found. The boundary-dominated, or -influenced, flow periods may be split into two parts. The first is represented by an approximate one-half slope, and denotes the transient hitting the first boundary to the drainage area. The second boundary is indicated by the onset of the unit slope of the pressure derivative. After a well is in fully boundary-influenced flow, it is often too late to consider refracturing unless the new fractures can somehow be induced to contact new reservoir, most likely in untreated or undrained sections of the wellbore.

When the reservoir transmissibility is known, along with pore pressure, fluid saturation, and system compressibility, the distance to each apparent boundary can be determined and cross-checked with the linear-flow plot shown in Fig. 6. The ratio of the two boundary distances gives the drainage aspect ratio. The two bounding distances may be interpreted as the fracture and well spacing. In the case of a horizontal well, the total system $k{\cdot}h$ will be the composite of all producing fractures. By either assuming the number of fractures contributing, or constraining the system permeability to the DFIT permeability for a single fracture, the total drainage area for the well can be determined, along with the fraction of the lateral-contributing production. Guessing at the wrong number of contributing fractures in this analysis will cause the drainage area per fracture to decrease, but the total drainage area of the well is fixed by the boundary events.

Fig. 9 shows a rate-transient analysis for a horizontal well initially completed with 16 fracture stages. The drilled lateral is approximately 5,000 feet long. The type curve shows that the well is clearly in boundary-influenced flow, with a unit-slope pressure derivative starting at a dimensionless time of approximately 0.3. Matching on permeability and assuming one effective frac per stage, the type curve and linear-flow plot both show approximately 30% of the drilled lateral length contributing to production. This 30% is illustrated by the schematic at the left that shows the drilled-well length, effective fracture length, and drainage area and aspect ratio of each fracture drainage area in relative scale. This well is clearly a strong candidate for refracturing if the reasons for the incomplete drainage can be determined.

Why might 70% of the lateral be failing to contribute to production? Mechanical issues should first be ruled out. A cleanout to the toe should be conducted to ensure that the liner is not collapsed or there are no sand, salt, or scale plugs present in the well. If possible, some production profile should be attempted to determine how the effective inflow points are distributed. The schematic places the total drainage at one end of the well, but in reality, it may be distributed randomly along the well. Are some fractures water-logged by being in a toe-down condition? Are some in low points in the well and standing under water? Are some perforations plugged by scale or other debris? Is the reservoir quality along the lateral highly variable, with large sections of nonproductive interval that are not really fracturing targets? Answering these questions may require extensive well testing and logging runs. Answering them correctly may determine whether the well is truly a refracturing candidate or is already operating at its true potential with the 30% contribution.

Replacing Damaged Conductivity

One justification that is used for refracturing is to replace damaged proppant-pack conductivity. After some producing time, the proppant pack, which essentially behaves as a fixed sand-bed filter, can accumulate damage from scale, fines, salt plugging, paraffin waxes, and asphaltene deposition. Laboratory data on long-term proppant conductivity show that performance will degrade continuously over time, even in ideal laboratory conditions with clean and filtered single-phase brine flow (STIMLAB Consortium, 2005–2015, unpublished). It can be expected that conductivity will drop significantly during several years of production.

However, the importance and impact of conductivity loss over time must be considered along with the transient reservoir behavior. At early times in the well's life, such as immediately after stimulation, the well is in some form of linear flow, producing with a high drawdown and supported by initial reservoir pressure. Flow rates are high, and the fracture conductivity is critical to be able to transmit the high fluid rate from the reservoir to the well. As shown in Figs. 1 and 2, the rate in many unconventional-reservoir wells declines at something above 75–80% in the first year. As the flow rate from the reservoir drops, the fracture conductivity becomes less important and is no longer the choke in the flow system. After the reservoir transient deliverability becomes the dominant control on rate, the fracture can transmit the low flow rate to

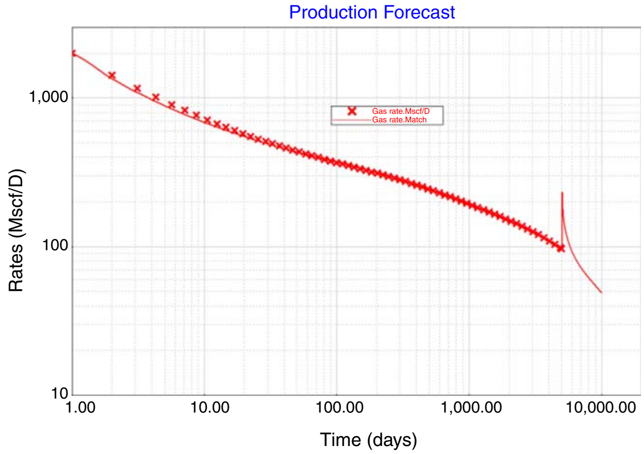

Fig. 10—Gas-production rate for a 5,000-ft horizontal well with ten effectively contributing fractures. Each fracture has an effective infinite-conductivity length of 30 ft. At 5,000 days, the well is in boundary-influenced flow, and a shut-in period of 30 days to build up reservoir pressure is applied. Initial production after the shut-in shows an increase of ≈230%.

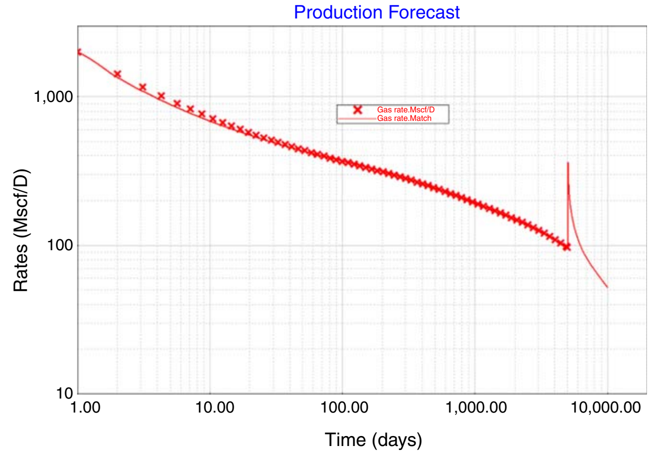

Fig. 11—Gas-production rate for a 5,000-ft horizontal well with ten effectively contributing fractures. Each fracture has an initial effective infinite-conductivity length of 30 ft. At 5,000 days, the well is in boundary-influenced flow, a shut-in period of 30 days is applied, and the well is "refractured" by increasing the effective infinite-conductivity length to 60 ft. Initial production after the shut-in and refracturing treatment shows an increase of ≈350%.

the well, even with substantially decreased conductivity. Under these conditions, replacing the damaged conductivity, and even substantially increasing the effective length of the fracture, will do little to improve total reserves recovery. As noted previously, adding reserves to the well requires adding contacted reservoir volume to the well drainage system, not just improving the connection to the existing drainage volume.

The impact of refracturing vs. a simple shut-in period to recharge and build up reservoir pressure is illustrated in the examples shown in **Figs. 10 through 12** that follow. These figures show a case representing a 5,000-feet horizontal well with 10 effectively contributing fractures, each having an effective infinite conductivity length of 30 feet. The well is produced for 5,000 days (13.7 years) to illustrate the impact of a recompletion after the well is in boundary-influenced flow. In Fig. 10, the well is shut-in for a 30-day extended buildup, allowing the reservoir pressure to stabilize at the current depleted average pressure. The well is then put back on production at the same flowing-pressure conditions as before the shut-in. The instantaneous rate is increased by ~230% when the well is put back on production. This is a reservoir transient response to re-establishing the early linear-flow period. The fracture conductivity and effective length are unchanged.

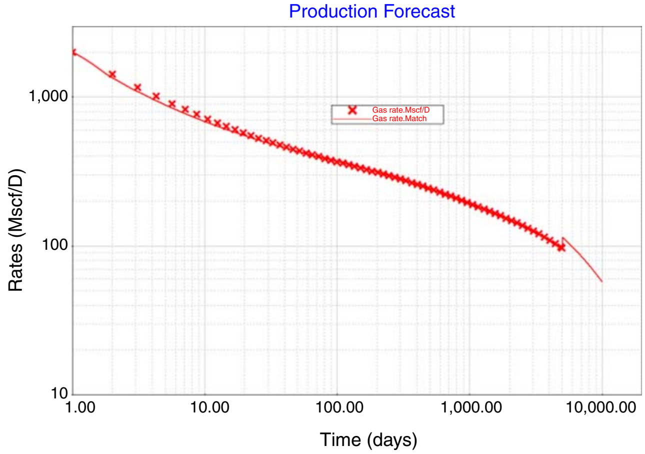

Fig. 12—Gas-production rate for the same well as in Fig. 11, except in this case, the well is only "refractured" by increasing the effective infinite-conductivity length to 60 ft with no associated shut-in. Initial production after the shut-in and refracturing treatment shows an increase of ≈20%.

In Fig. 11, the production-decline profile for the same well is shown for a 30-day buildup and refracturing treatment that doubles the effective fracture length. This is an extremely effective refracturing that is likely not possible in an actual well. The result is that the initial post-refracturing rate increases by ≈350% compared with the prefracturing rate. Note that the response is transient, and much of the benefit is caused by the re-establishment of the pseudolinear flow after the buildup. The well returns to its pre-refracturing decline after a few years of accelerated production. The spike in rate does not represent added reserves, only the acceleration of the reserves that would have been recovered without the expense of the refracturing treatment. Economic justification of the refracturing must be supported by the acceleration component.

Fig. 12 shows the result of the same refracturing treatment, doubling the effective fracture length by replacing damaged conductivity and extending the fracture, without the benefit of the 30-day shut-in period with the reservoir-pressure buildup. The initial rate increases by approximately 20% for a short period of time. This brief increase in rate will probably not generate enough acceleration to pay for the refracturing treatment. In none of these cases is the ultimate recovery from the well altered by the shut-in or the refracturing treatment.

These cases demonstrate that much of the presumed benefit from refracturing may actually be more tied to the transient response of the reservoir. In such a case, the post-refracturing initial production and decline may be more a function of the buildup period and reservoir transmissibility (how fast can the pressure stabilize) and the volume of the drainage area (how much energy is available for recharge) than the effectiveness of the new fracture length and conductivity. The same analogy can be made for refracturing performed during the transient flow period, before the well reaches boundary-influenced flow.

Fracture Reorientation

In some cases, a well may be drilled in a stress azimuth that generates a long but narrow drainage area that appears to be less than well spacing. The initial completion may have resulted in a dominant longitudinal fracture, with minimal transverse stimulation (Barree and Miskimins 2015). Production and associated depletion of pore pressure may increase the net effective stress on the rock, and can, in some cases, change the preferred direction of fracture growth. In reservoirs with high initial pore pressure, the total minimum-maximum-horizontal-stress differential may be

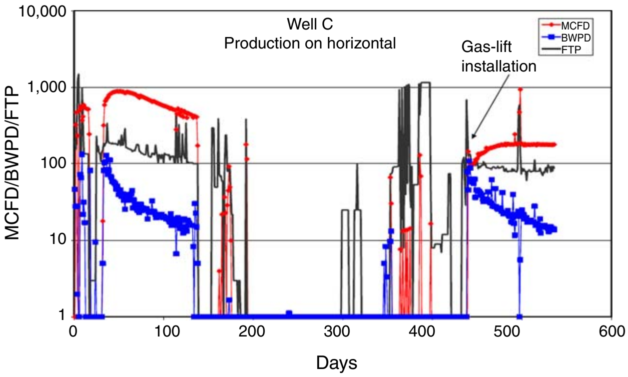

Fig. 13—Impact of an effective gas lift installation in a horizontal well (from Pohler et al. 2010).

smaller than the near-wellbore tortuosity and perforation entry friction encountered during initial stimulation. In this case, most of the fracture-treatment volume will enter the longitudinal fracture component. With depletion, the net stress will increase, and the fracture-treating pressure will decrease. If the refracturing completion has lower entry friction and the induced net stress generates any horizontal-stress differential, the new fracture may tend to be more transverse than the original.

Induced strain in the rock caused by the proppant pack placed in the original longitudinal fracture may be sufficient to overcome the original low stress differential. This can be especially true in hard, high-modulus rocks. An accumulation of scale and salt plugging in the longitudinal fracture may also force injected fluid (during the refracturing treatment) to follow a different path and contact reservoir that was not previously stimulated.

Any plans for fracture reorientation seem to require a fairly low initial stress differential in the system. This may allow the effects of production (depletion, damage, and others) and the previous fracture treatment to alter the maximum-stress direction enough to cause the reorientation of the refracturing. A strongly stress-biased system is unlikely to allow reorientation as a result of either depletion, damage, or induced net stress. Diagnostics including DFITs, microseismic monitoring, borehole-breakout analysis, differential caliper, and borehole-image logs may be useful in determining the original and current degree of stress differential.

Well-Operating Conditions

Another major issue that frequently instigates refracturing operations is a steep production decline that can be caused by the loading up of the well. This is particularly true for horizontal wells in which the critical unloading velocity in the horizontal section is much higher than expected for vertical wells (Veeken et al. 2010). Stratified flow of fluids with different densities causes liquids to accumulate in the wellbore, especially in any low points along the well path. Terrain effects, caused by alternating uphill and downhill flow, also tend to accentuate the accumulation of liquids. When the dips in the well path are larger than the wellbore diameter, this can lead to slugging or complete loss of production from sections of the well. Vertical fractures connected to these liquid-filled low points may also remain loaded with fluid (likely water) and be unable to develop useful permeability to oil and gas, or develop any effective flowing length.

Both before refracturing, and as an operating practice after refracturing, some form of artificial lift should be seriously considered. Hanging a pump, tubing tail, or gas lift mandrel in the vertical section of the well, hundreds (or more) of feet above the lateral, will not provide sufficient velocity in the lateral to sweep it clear of accumulated fluids. Having a high drawdown, or low bottomhole flowing pressure (BHFP), does not necessarily provide high velocity in the well, especially in a low-permeability reservoir. Low BHFP also does nothing to affect the saturation distribution and relative permeability or capillary pressure functions in the reservoir and fracture proppant packs. Without a continuous hydrocarbon-phase saturation and sufficient energy to overcome capillary and gravity effects, stable flow from fractures may be impossible.

Several artificial-lift systems may be used in horizontal wells, including hydraulic pumps, jet pumps, and gas lift. For the system to be effective, it must be able to provide lift and velocity in the horizontal section of the well. The “annular velocity enhancement” gas lift method (Pohler et al. 2010) provides a system that can be deployed in horizontal wells. **Fig. 13,** from the referenced paper, shows the change in gas-rate decline, resulting from the installation of this production-enhancement system. Understanding the inflow profile along the lateral well may suggest that loading and inefficient production operations, usually caused by setting tubing too high, are the primary causes for rapid declines, low recovery, and apparent loss of drainage area or lateral contribution. These wells may benefit more from a change in operating conditions than from refracturing.

Well Conditioning

After a candidate has been selected for refracturing treatment, the well should be conditioned before the treatment to allow the highest possible chance of success. Conditioning may be as simple as a cleanout to the toe or a verification of casing integrity to ensure that anticipated treating pressure can be safely contained. In most cases, the well will have many open perforations or sliding-sleeve fracturing ports. Simply bullheading the refracturing treatment into the well gives minimal control of fracture placement. Retreating existing perforations also minimizes the chance of contacting a new reservoir, which, as noted previously, is the goal of the refracturing treatment.

More-effective restimulation can be achieved by plugging or inducing diversion away from existing fractures and creating new, and more-efficient, fracture-initiation sites. Mechanical isolation of individual perforations sets is costly and time-consuming, but may be an option for coiled-tubing-conveyed treatments. In many cases, the use of a particulate diverting material to at least partially plug existing-fracture entrances is fast and cost-effective (Allison et al. 2011).

The choice of a diverting agent is important. Particulate diverters that require active mixing with a solvent, such as benzoic acid flakes (for oil) or graded rock salt (for water), may seem to be effective diverters. After the diverter forms a plug, it may be difficult or impossible to contact the plug with enough solvent to achieve aggressive mixing and to dissolve the diverter plug during production. If the diversion treatment is intended to permanently block old fractures, this is obviously less of a concern.

Thermal degradation or spontaneous decomposition of particulate diverters, or use of materials that do not require dissolution in a solvent, will clean up more effectively during production, after the refracturing treatment. It is advisable to design the diversion treatment to achieve an increase in injection pressure of at least 300 to 500 psi compared with the start of a diverter injection. This pressure range should be sufficient to reduce fluid entry to the existing fractures while the treatment is being performed.

New fracture-initiation sites can also be spaced between the pre-existing fractures. This can be performed with conventional shaped-charge perforators or by abrasive or hydrojetting with a nozzle tool on tubing or on coiled tubing. In either case, the goal is to achieve the lowest breakdown pressure and least tortuosity possible. A low breakdown pressure will reduce the chance of simply reopening existing fractures. Low tortuosity or entry friction will decrease the dominance of any longitudinal fracture component.

Achieving this goal may require an orientation of the new perforations relative to the circumference of the hole. As shown in **Fig. 14,** the azimuth of the well, along with the in-situ stress tensor, sets up a tangential or hoop stress around the well. In a normal stress environment, the maximum compressive stress will be at the sides of the hole, and the minimum stress, or most likely breakdown point, will be at the top and bottom of the hole. The

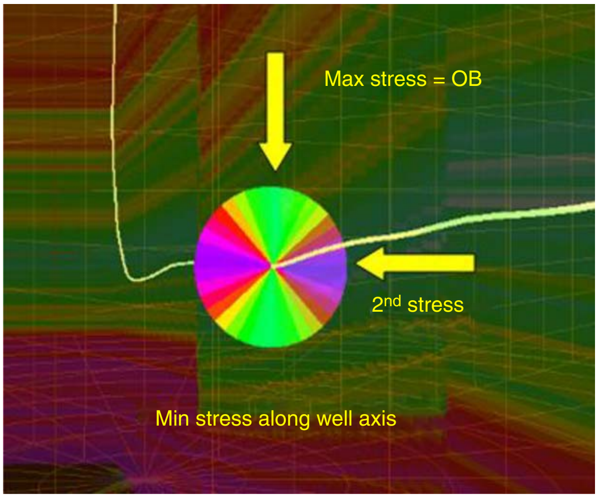

Fig. 14—Tangential stresses around a horizontal wellbore. The horizontal well is shown by the yellow line. The minimum in-situ stress is indicated by the colors in the background ("hotter" colors indicate a higher stress, "cooler" colors a lower stress). The rose diagram placed on the wellbore indicates the tangential stress at that point on the well. Under the shown well circumstances, the minimum tangential stress is at the top and bottom of the well, indicating where initial breakdown will occur.

difference between the breakdown pressures at these two points can easily exceed 2,000 psi. Minimum treating pressure will be found by understanding the current hoop stress, as altered by production, and allowing the fracture to start at the lowest stress point.

Abrasive jetting usually leads to the least perforation damage and lowest breakdown pressure, but it is time-consuming and can be expensive. Shaped-charge perforators are fast and effective, but can cause severe stress-cage formation and tortuosity, leading to high treating pressures. The goal for the refracturing should be to minimize damage at the fracture entrance. If perforation charges are used, this can be accomplished by selecting low-gram-weight charges (7 to 9 g) that generate entry-hole diameters of 0.25 to 0.32 in. This hole size is sufficient to accept up to 20/40-mesh proppant without bridging. Depth of penetration in a fractured completion is inconsequential and should not be a design consideration.

Because diversion slugs will likely be used in the refracturing treatment, and considering that the existing perforations are likely not completely plugged, there is no reason to attempt a limited-entry perforation design for the refracturing. At the same time, overperforating is certainly not recommended. Shooting more holes than necessary opens opportunities for more loss of control of the fracture placement. A good compromise should be sought. Limited experience suggests that a shot density of no more than 3 shots/ft, 180 phasing, with 2- to 3-ft perforated intervals is acceptable. For abrasive jetting, two jetted holes at 180° are sufficient for each entry point.

Job Design and Placement

In job design and execution for a refracturing treatment, several factors should be considered. First is the spacing of offset wells and the pore-pressure profile that has been established during the producing period before refracturing. An offset producing well will likely have a region of low pressure extending from it, possibly as far as the drainage area of the target refracturing well. The pore-pressure profile extending from the treatment well into the reservoir must also be considered in the design. As the fracture grows into the area of lower pore pressure, it will encounter lower fracture-extension pressure.

A "worst-case" scenario is shown in **Figs. 15 through 17.** This case represents an infill well drilled 660 ft offsetting a producing well with a 2,000-psi depletion at the producing well. Fig. 15 shows the stress differences that occur around the production compared with the treatment well as a result of this depletion. A single gelled treatment consisting of 50,000 lbm of 30/50 white sand, CMHPG-Zr crosslinked gel, and pumped at 20 bbl/min (all modified to represent a single-cluster entry point in a multistage horizontal treatment) is shown in Fig. 16. In this case, a slight impact of the depletion is noted. However, a slickwater treatment shown in Fig. 17 (34,000 lbm of 30/50 white sand at 20 bbl/min) grows rapidly into the depleted zone around the offset well, and is severely affected by the offset depletion. Most of the fluid and proppant are placed in the low-pressure area around the old well, with little effective stimulation of the new well. The massive influx of water to the old well could damage its productivity or cease its production entirely, resulting in reserves write-offs.

As shown in this example, when refracturing, the pore-pressure profile around the treatment and all offset wells must be considered. Offset wells may need to be shut-in for some time to allow reservoir pressure to partially buildup and stabilize. The degree of depletion around the treatment well should be understood and taken into account in the refracturing design. Exces-

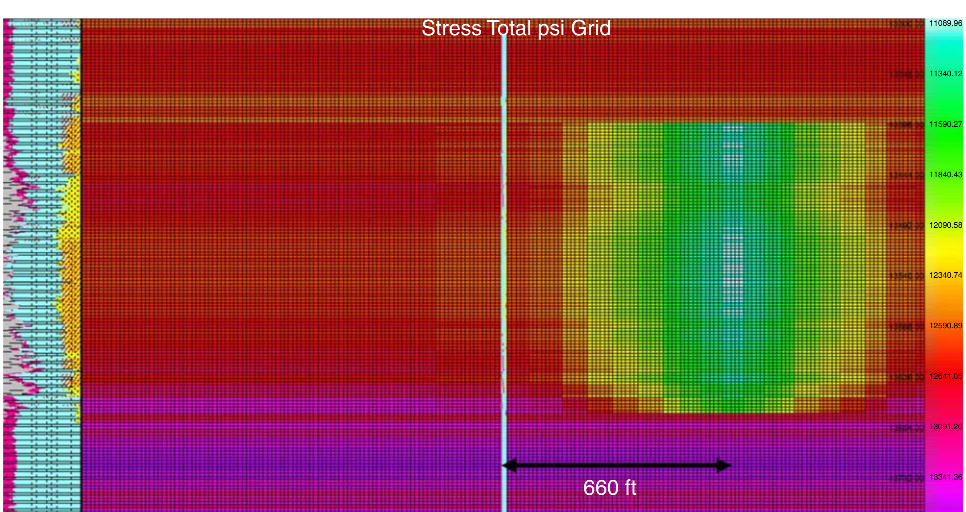

Fig. 15—Total stress (minimum in-situ) as a result of pore-pressure depletion in offset well. The wellbore from which the fracture will start is shown in blue in the center of the figure. The offset producing well is in the pressure sink to the right with 660-ft spacing. The total stress in psi is indicated by the legend to the right.

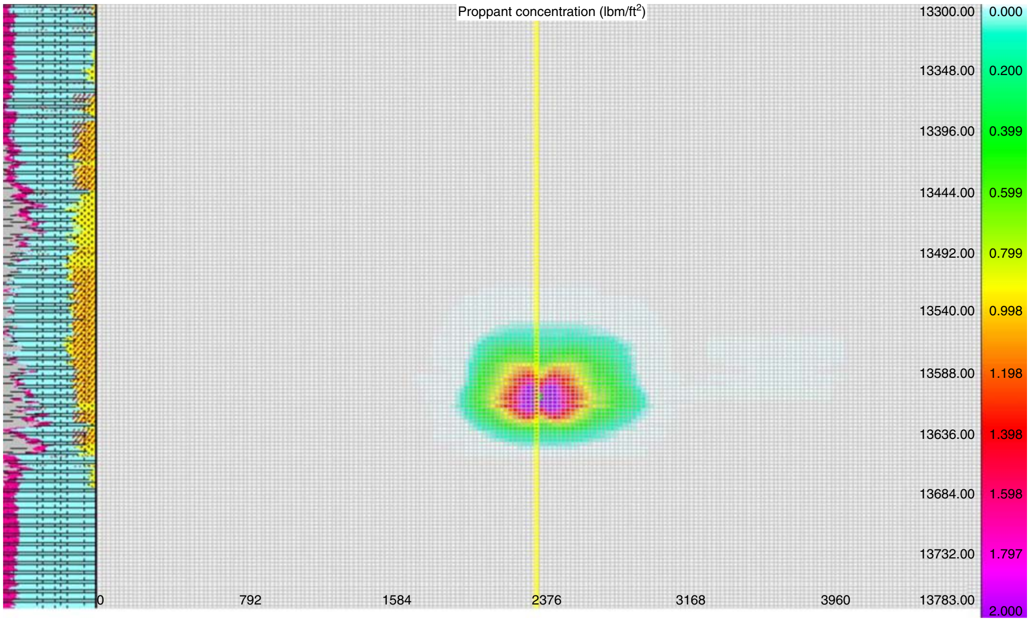

Fig. 16—Impact of offset-well depletion on a gelled fracture geometry as a result of the pore-pressure depletion shown in Fig. 15. The scale to the right provides proppant concentration in lbm/ft^2.

sively large slickwater fracture treatments may either "bash" the offset well or remain contained within the depleted zone of the treatment well. Smaller, more-aggressive proppant schedules with hybrid or crosslinked-gel fluid systems are more effective at achieving diversion and near-well conductivity for the refracturing well while minimizing damage to offset wells.

Rather than treating the entire conditioned and reperforated wellbore at once, multiple stages separated with particulate diverters are recommended to improve coverage. The simulated treatment in **Fig. 18** shows the response to diverter stages pumped after each sand ramp. The diverter is intended to partially block fluid entry to the perforation clusters taking the most fluid, and to help improve uniformity of job placement, although this is not always the result (Wheaton et al. 2016). In the Fig. 18 example, the diverter achieved a pressure step of 600–800 psi. The number of diverter stages should be adjusted depending on the length of lateral to be treated and the number of new entry points. Current experience continues to show that smaller total job size with more-aggressive proppant placement and diversion yields a better refracturing performance.

Post-Treatment Evaluation

A successful refracturing treatment may lead to additional candidates and an expansion of the refracturing program in a field. As such programs grow, it is important to measure the effectiveness of the refracturing in terms of real production. During the conditioning and treating of the refracturing well, there will some shut-in time that allows pressure to build up around the well. When put back on production, it is not uncommon to see a short spike in production. This initial rate spike is not necessarily a good indication of the success or failure of the refracturing. Production must be monitored with rate-transient analysis, and phase rates and flowing pressures must be recorded after the treatment so that any change in well performance can be quantified.

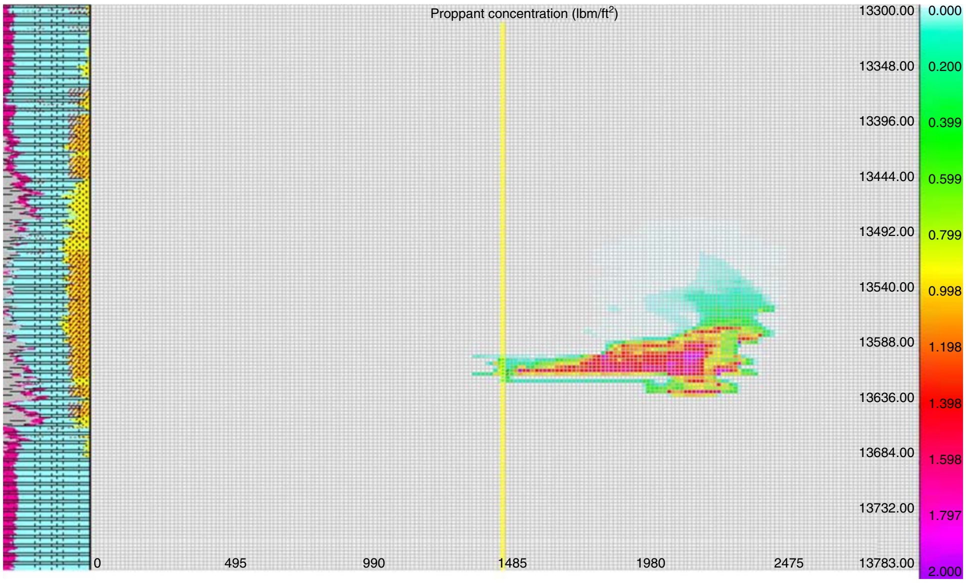

Fig. 17—Impact of offset-well depletion on a slickwater fracture geometry as a result of the pore-pressure depletion shown in Fig. 15. The scale to the right provides proppant concentration in lbm/ft^2.

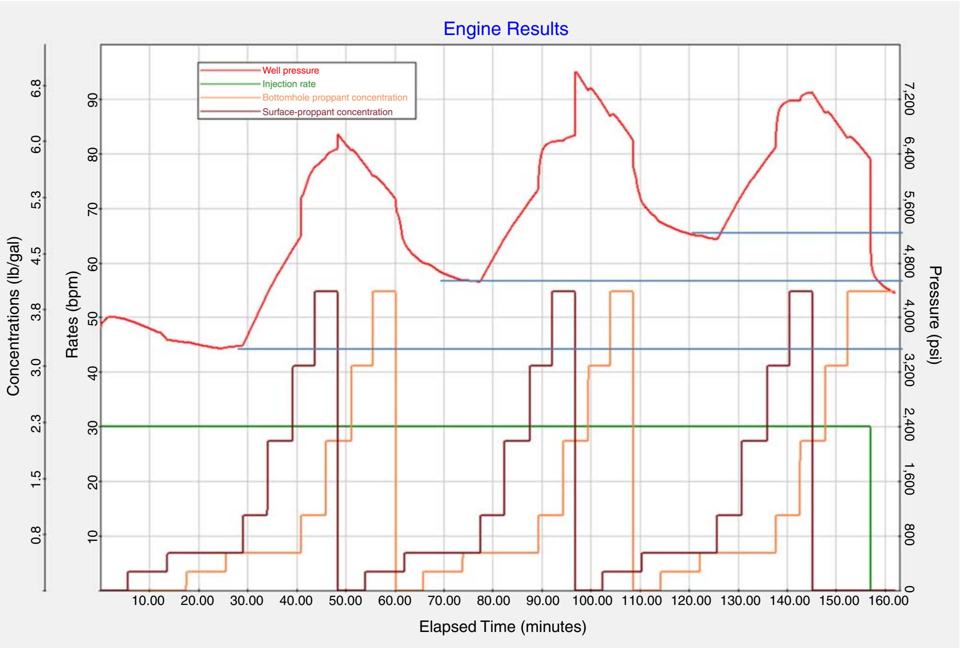

Fig. 18—Simulated example of particulate diversion effect on treating pressure.

Assuming that the well's production history has been analyzed with a rate-transient technique, it should be a relatively simple matter to enter the post-refracturing data into the same model and compare the forecast for the original completion to the new completion. If the job was unsuccessful, the production should return to essentially the same decline profile after a short transient bump in production rate. If the job has succeeded in contacting new reservoir, then a difference in effective well length, drainage area, or change in aspect ratio will be apparent as an increase in the total energy, driving production in the system. The effective fracture length may or may not change with the refracturing, but the degree of success is controlled by the change in the amount of reservoir delivering to the well.

The incremental production resulting from the refracturing should then be quantified and compared with the overall cost of the treatment, including any well workovers and conditioning times, deferred production, and other economic factors before assigning a positive economic value to the refracturing treatment. If the job was a technical and economic success, adding value to the asset, then the search for additional candidates should be expanded.

Conclusions

The restimulation of horizontal wells has tremendous potential; however, the degree of success will depend greatly on candidate selection and treatment design. Simply repumping the same original treatment into a multistage horizontal well will likely provide highly unsatisfactory results. The following considerations should be taken into account when considering a refracturing program:

- Under most conditions, the success of a refracturing treatment will depend on contacting a new reservoir that has not been previously drained. This can be accomplished by treating sections of the well that were not adequately treated during the initial stimulation, increasing the effective drainage height, or reorientation of fractures.
- If the reservoir deliverability is sufficient, replacing damaged conductivity can also result in satisfactory results.
- Not all wells are candidates for refracturing, even if production is not what is expected or desired. Wellbore diagnostics and production analysis (rate-transient) are both key components for the determination of a refracturing candidate.
- Before proposing a refracturing treatment, the operating conditions should be evaluated to verify that the well is operating under the most ideal conditions possible and that the refracturing treatment is actually needed and can provide beneficial results.
- When designing a refracturing treatment, any pore-pressure depletion in the area of the subject well should be considered along with the impacts that it can have on the refracturing design. Under various conditions, this pore-pressure depletion can have a significant impact on any fracture growth and retreatment results.
- As with any stimulation treatment, after the refracturing treatment has been performed, a post-treatment production analysis should also be completed. This analysis can verify if the refracturing goals were met and if future retreatments in the same area could be beneficial.

Nomenclature

A = area, L^2, acres
h = reservoir thickness, L, ft
k = permeability, L^2, md
Nf = number of contributing (producing) fractures
p_{wD} = dimensionless wellbore pressure
t = time, t, days
t_{DA} = dimensionless time on the basis of area
X_f = effective half-length, L, ft

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Robert D. Barree is president and principal investigator of Barree & Associates. Previously, he was a senior technical consultant at Marathon's Petroleum Technology Center. Barree has been involved in the development of hydraulic-fracture design simulators and fracture-diagnostic procedures for nearly 40 years, and is the author or coauthor of more than 70 technical publications. He has served as SPE Distinguished Lecturer on the topic of new philosophies in hydraulic fracturing, and has served on many technical committees for SPE annual and regional meetings, Applied Technology Workshops, and Forum Series. Barree is a registered Professional Engineer in the State of Colorado and holds degrees in petroleum engineering from Pennsylvania State University and the Colorado School of Mines.

Jennifer L. Miskimins is the associate department head and an associate professor in the Petroleum Engineering Department at the Colorado School of Mines. Her research interests focus on the areas of hydraulic fracturing, stimulation, completions, and unconventional reservoirs. Miskimins has authored or coauthored more than 70 technical papers. She holds a BS degree in petroleum engineering from the Montana College of Mineral Science and Technology, and MS and PhD degrees in petroleum engineering from the Colorado School of Mines. Miskimins served as an SPE Distinguished Lecturer during the 2010–2011 and 2013–2014 seasons, was the executive editor of *SPE Production & Operations* from 2008 to 2011, and was the recipient of the 2014 SPE International Completions Optimization and Technology Award.

Kevin J. Svatek is a senior technical consultant at Barree & Associates. He previously worked as a deepwater completion consultant before joining StimLab/ProTechnics division of Core Laboratories as a senior technical engineer. Svatek's research interests include hydraulic-fracturing design, analysis, and simulation; completions; and unconventional reservoirs. He holds a BS degree in petroleum engineering from Texas A&M University and is a member of SPE.