CANYON SAND - A FRACTURING CASE HISTORY UNDERSTANDING THE RESERVOIR

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ABSTRACT
In 2002 TEMA Oil & Gas ("TEMA") purchased the Simpson-Mann field in Val Verde and Crockett counties. The Simpson-Mann field's completion horizon is the Canyon Sand. From their prior Canyon Sand experience, TEMA's asset management team was convinced that better completions could be made. While the initial post-acquisition completions were equivalent to the field's historical completions, TEMA was disappointed in the quality of their new wells. Additionally, TEMA did not think they were improving their understanding of the field's critical characteristics; consequently, they decided to change. Starting in 2003, TEMA changed their techniques and expectations to enhance their understanding of the Simpson-Mann field. While not confirmed, the current theory dictates a radical departure from historical stimulation techniques.

INTRODUCTION
The Simpson-Mann (Canyon) field is located in West Texas along the southern edge of the Val Verde Basin and is considered an extension of the Ozona "tight gas" trend. The Canyon sands were deposited as a series of relatively deep water submarine fans with the primary sediment source being the Ouachita highlands to the south and a secondary source to the north (probably the Ozona Arch and/or the Central Basin Platform). The Canyon interval in the Simpson-Mann area exceeds 6,700 feet in gross thickness with the upper 1,500 feet composed of interbedded sandstones and mudstones. These sandstones range in thickness from 2 feet to greater than 40 feet with the majority being less than 20 feet and are the "pay" sands at Simpson-Mann. The balance of the Canyon is a section of mudstones with scattered shale stringers.

In 1999, TEMA Oil and Gas (TEMA) decided to acquire the Simpson-Mann field from EOG. Because the field is recognized as an extension of the Ozona "tight gas" trend and is in close proximity to the Ozona field, TEMA discerned that the same type of wells being completed in the Ozona field could also be completed in the Simpson-Mann field. After two years of effort, trying many different stimulation techniques, TEMA was still not satisfied with the quality of their wells or their completions. This caused TEMA to go back and review some of the basic assumptions upon which their original analysis was based.

ANALYSIS
According to Gary Swindell, SPE Paper 35204, *Reserves and Performance of Canyon Sand Gas Wells, 1970-1994*, which is an in-depth analysis of the Canyon sands in the Ozona and Sawyer fields, TEMA should expect an average well of 12,000 MCF/month initial production, which undergoes a steep hyperbolic decline but typically gives EURs of 650 MMCF/well on average.

Initial production of wells in the Ozona field exhibits a log-normal distribution; therefore, multi-well programs are required to ensure that field average well numbers are achieved. In other words, most wells will not achieve target performance, and a few wells will significantly impact and push average well performance higher. Additionally, Swindell's analysis of the Ozona and Sawyer fields clearly shows that from 1970 to 1985 new well performance was declining and that this trend was reversed in 1991. While not being able to acquire all of the facts, Swindell postulates that the striking improvement in well performance was driven by improvements in well completion and stimulation techniques.

TEMA was aware of these facts when they initiated their drilling program. While achieving some success, TEMA's drilling program never garnered the type of wells required to match Ozona's IPs or well qualities. Note: Figure 1 plots well quality in terms of each well's permeability, thickness, and fracture half-length versus cumulative first 12-months' production from each well in the Simpson-Mann field. To achieve TEMA's objectives, an average well quality of 3.5 is targeted. As the graph depicts, this target has not been met. Additionally, considering the thickness of the sand bodies, logging analysis and fracture simulation, well qualities 4,5, and 6 should be regularly achieved. As Figure 1 shows, while they should be achieved, these qualities have not been achieved.

To better understand geology, the impact of stimulation jobs, and derive a strategy for moving forward, TEMA brought together their technical staff, suppliers, and consultants to review all available data. During their review, some interesting facts stood out, which caused the team to reconsider what they thought they knew about this reservoir. Unlike Ozona wells where frac gradients average 0.7 psi/foot, the frac gradients of the Simpson-Mann wells typically run 1 psi/foot or greater and fluid efficiencies of 30% or more are measured. In very "tight" sands this high leak-off rate is normally attributed to natural fractures. Fracture gradients of 1 psi/foot are typical for wells with complex frac systems. Subsequent to these findings, cores from the Simpson-Mann were reviewed and horizontal fractures were observed.

After reviewing the aforementioned data, the team questioned whether the induced fracs from the stimulation jobs were truly vertical or biased toward the horizontal. The teams decided to stimulate the Meadows 1107 well as if induced fractures propagated horizontally or at least were biased toward horizontal. The following explanation, courtesy of Dr. Jim W. Crafton, was the bases upon which the new stimulation treatment design was based:

"Since surface contact area of the hydraulically-induced fracture with the producing formation is the primary consideration in hydraulic fracture stimulation, consider a near-vertical fracture that is 20 feet tall by 200 feet of single wing length. It has 16,000 square feet of contact surface. By contrast, a high angle, near horizontal "pancake" fracture only has to have a radius of about 50.5 feet to have the same contact area. That simple geometry issue puts a very different light on stimulation design strategy in areas where pancake fractures can be expected to occur."

"Since leak-off or proppant mobility are strong functions of the surface area, proppant concentration scheduling is quite different for the two geometries. Since for the vertical fracture, contact or leak-off area only grows linearly as the fracture grows, proppant concentration can ramp approximately linearly. However, for the pancake fracture, area grows as the square of the fracture radius (fracture length). Therefore, to maintain bed mobility, the concentration increases must grow approximately as the inverse of the square of time (assuming a constant pumping rate), to prevent a tip screen-out."

"Again considering the two fracture geometries, suppose they are both 1/8th inch wide propped fractures and producing 1000 MCF/D at 1000 psi bottomhole flowing pressure. Assume the wellbore in 4.5 inches in diameter. The outflow velocity of the gas from the vertical fracture is about 20 feet per minute, whereas the velocity from the pancake fracture is nearly three times as great. The velocity difference and the effect of overburden stresses dictate that tail-in proppant concentrations for a pancake fracture design must be considerably different from a vertical design. Fundamentally, it implies a much higher proppant concentration and possibly a high-strength proppant for the pancake fracture."

Significant changes were made to the stimulation plan for the Meadows 1107. By reviewing temperature logs, natural fracture systems were identified, and these intervals were perforated with two tightly spaced sets of perforations. These intervals were perforated using 4 SPF at 90 degrees. Assuming the fracture would be horizontal or nearly so, the treatment schedule was modified to generate near-wellbore conductivity versus fracture half-length. Using 16-30 Ottawa sand, the stimulation's job sand density was ramped to 6 PPG in just 5 minutes. Additionally, a unique chemical tracer was added to each of the pad, the ramp sand, and the 6-PPG sand stage. Note: Most chemical tracer jobs show a first-in, first-out pattern, which is generally considered indicative of a convection-type displacement. Note Figure 2, which clearly shows a last-in, first-out pattern. This last-in, 6-pound sand stage, first-out pattern is considered indicative of a piston-type sand displacement. If the induced fracture is horizontal or nearly so, being that there is no gravity segregation; one would expect that the flowback of the tracer would indicate a piston-type displacement of sand. Subsequent to this treatment, the Meadows 1107 initial production was 10,000 MCF/month, and TEMA considers the latest treatment to be moving in the right direction.

SUMMARY

At first blush, the Simpson-Mann and Ozona fields are strikingly similar. Both fields produce dry gas from Canyon sands with 10% porosity and 0.1 md permeability. Additionally, cores from both fields show similar high permeability streaks. However, these similarities disappear when the reservoir is hydraulically fractured and the wells are put on production. The average Simpson-Mann well underperforms the average Ozona well. The disappointing performance of their wells caused TEMA to review the facts and make changes.

After compiling and reviewing pre- and post stimulation pressure data the team focused their attention on fluid efficiency and frac-gradient numbers. Since fractures are created perpendicular to the least principal stress and with frac gradients in Simpson-Mann at 1.0± psi/ft and 6,000 ft., then it makes sense that the over-burden could be the least principal stress which would make fractures biased toward horizontal. Additionally, even considering the effects of natural fractures, with typical fluid efficiency numbers of around 30% if hydraulically induced fractures were vertical the reservoir's permeability would be greater than observed in cores. All these facts indicate that the possibility of horizontal induced fractures is probable and future stimulation treatments should be designed to take that effect into consideration.

CONCLUSION

After reviewing the facts and concluding that hydraulically induced fractures could be biased toward horizontal the treatment scheme was changed for the Meadows 1107. This new treatment schedule produced a well that performed significantly better than previously wells. Additionally, the analysis of the chemical tracer confirmed a piston type displacement which is what is expected from a near-horizontal hydraulically induced fracture.

Simpton-Mann 12 month Cummulative Gas Production versus Well Quality Index

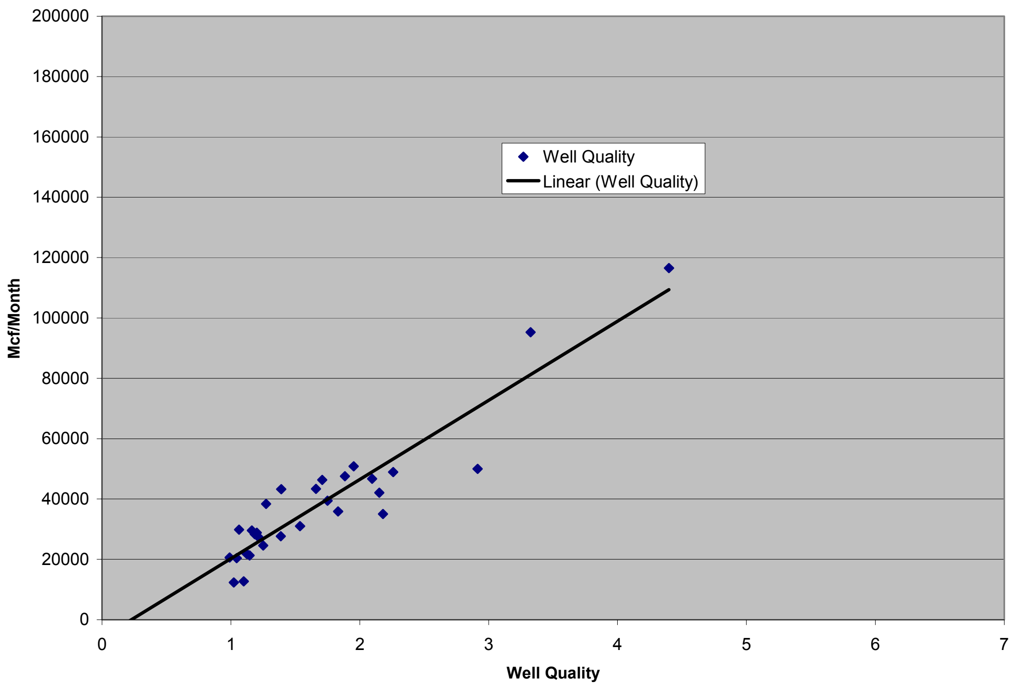

Figure 1

TEMA Oil and Gas - Meadows 1107

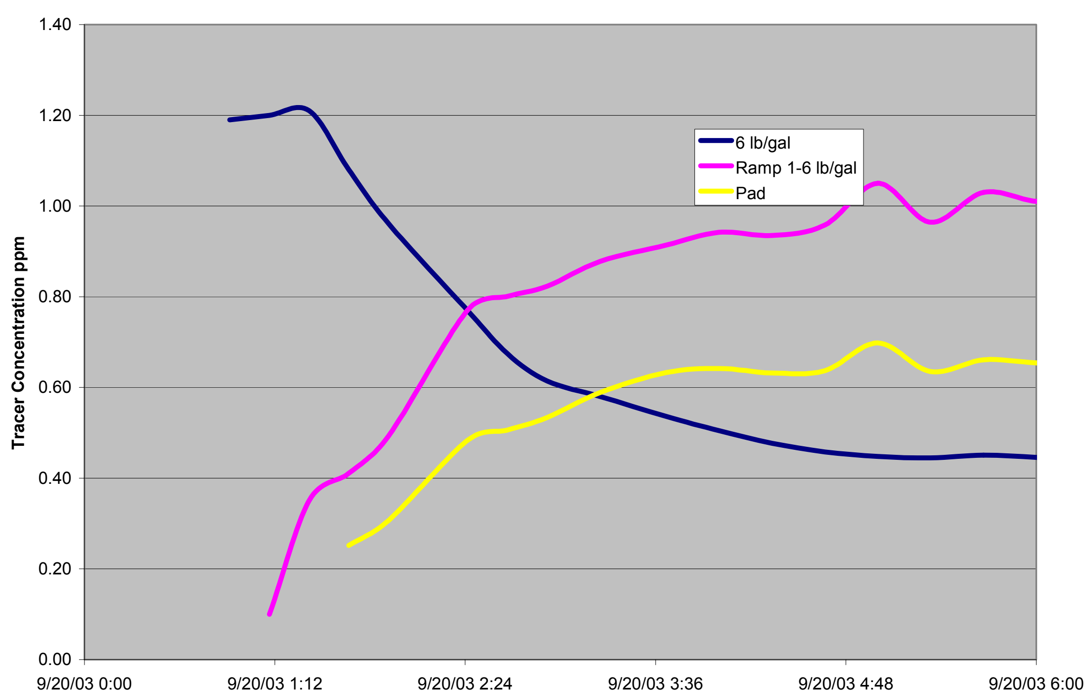

Figure 2