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Case Studies of High Viscosity Friction Reducers HVFR in the STACK Play

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Abstract

High viscosity friction reducer (HVFR) as a completions fluid has been tested in many premier plays in North America, such as the Bakken, Permian and Eagle Ford basins (Van Domelen et al. 2017). Increasing popularity due to production output and operational efficiencies have led to the first trials in the developing STACK play. This paper will describe the applications, observations and results from those field trials.

Three unique case studies were identified as optimal tests for the fluid. The first includes two nearly identical offset horizontal wells in terms of landing target, location, and completion designs. The lone differing variable between the two wells was a substitution of HVFR for gel, both linear and crosslink, in the pump design. The second case describes an application in an extended-reach lateral within thinning pay to optimize economics in stressed areas. The last case includes a horizontal lateral in the geologic heart of the play with consistent well results in surrounding sections.

Over the course of the three case studies, numerous benefits of the HVFR fluid system began to emerge. Operational efficiency was the earliest success, found by both the completion engineers and foremen, from reducing chemicals on location to pump design simplicity for the operator and stimulation company. Secondly, cost savings were realized due to the decreased number of chemicals required, ability to place high sand concentrations, and flexibility to reduce chemical concentrations during the completion as experience with the fluid increased. Lastly, well flowback exhibited the potential for equal or better production using HVFR over linear and crosslinked gels, theoretically due to the higher regained conductivities found in HVFR testing.

This paper showcases the potential for a relatively new treatment fluid which delivered increased efficiencies in an emerging North American asset. The same efficiencies provided by this system can potentially be realized through applications in other basins.

Laboratory Testing

The HVFR fluid system used for the work described in this paper was tested extensively in the laboratory prior to the start of this project in order to help ensure that the fracturing operations were successful. A summary of the pertinent lab tests which were performed is shown below:

- Frac mix water analyses
- Fluid rheology testing
- Formation sensitivity analyses
- Regain fracture conductivity
- Proppant transport

Frac Mix Water Analyses

Multiple water sources were used for this project based on logistical factors including the location of the wells in relation to the nearset source. Analyses for two of the water sources used is shown in Table 1. The analyses showed relatively low levels of Total Dissolved Solids (TDS) and overall hardness (calcium and magnesium), which was quite acceptable for preparing the HVFR. Viscosity development and break profiles will be discussed later in this section of the paper. In addition to the water analyses, bacteria testing was performed and identified the presence of corrosive bacteria which could be easily treated with a standard biocide.

Table 1—Analyses for Two Frac Water Sources

		
General Information	**Water 1**	**Water 2**
Fluid appearance	Clear	Turbid
pH	8.02	8.11
Oxidation Reduction Potential (5)	70 mV	61 mV
Specific gravity	1.000	1.000
Parameters	**Concentration (mg/L)**	**Concentration (mg/L)**
Alkalinity (1) (as $CaCO_3$ mg/L)	270	175
Total Hardness (1) (as $CaCO_3$ mg/L)	930	166
Calcium (1) (as $CaCO_3$ mg/L)	825	125
Magnesium (1) (as $CaCO_3$ mg/L)	105	41
Manganese (2) (as Mn)	0.2	1
Iron (2) (Fe)	0.01	1.18
Phosphate (3) (PO_4)	0 - 5	0 - 5
Sulfate (2) (SO_4)	1600	64
Barium (2) (Ba)	21	19
Hydrogen Sulfide (4) (H_2S)	0	0
Free Chlorine (as Cl_2)	0	0
Chloride (3) (Cl)	51	< 31
TDS (5) (as conductivity at 25C)	805	205.9

Fluid Rheology Testing

The next step in the testing program was to perform a rheological assessment of the HVFR system. Figure 1 shows the viscosity profiles for the HVFR prepared in one of the source waters at concentrations of 2, 3 and 4 gallons per thousand (gpt) of FR in the mix water. Two sets of viscosity profiles are shown on Figure 1; one set that included the addition of a liquid breaker designed for the system, and the other set without breaker. Note that the breaker provides a distinct reduction in the viscosity of the HVFR as compared to the fluid system without the breaker. In addition to the rheology and break testing, friction reduction has been evaluated with the HVFR in a laboratory flow loop and consistently provides friction reduction values of around 70%, regardless of variations in the mix water composition.

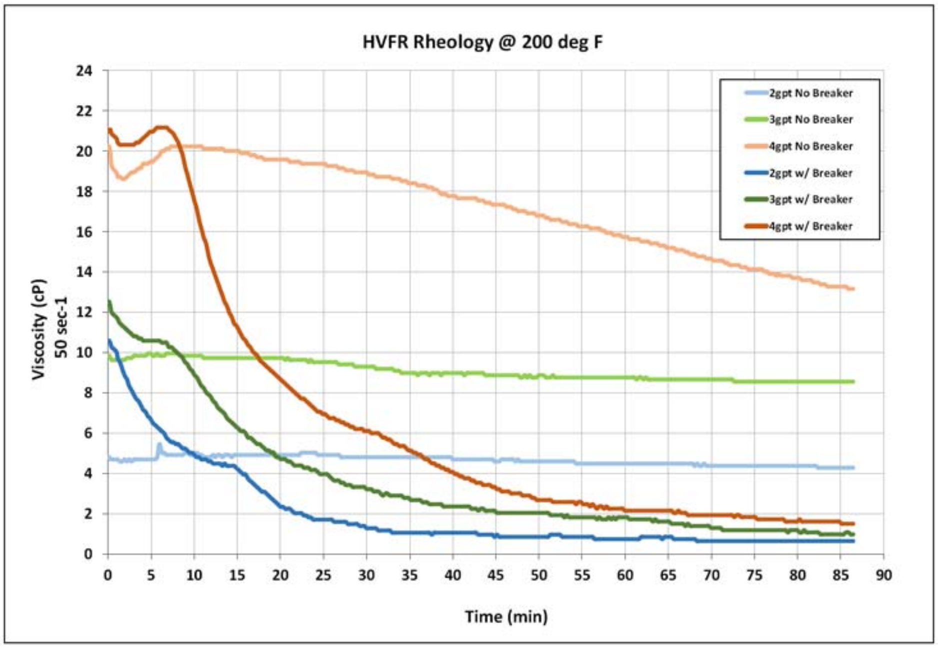

Figure 1—HVFR Viscosity Profiles at 200 deg F

Testing work with the HVFR system continues to evolve as future work will likely involve the use of higher TDS waters.

Formation Sensitivity Analyses

To assess the sensitivity of the formation mineralogy to the fracturing fluid system, capillary suction time (CST) and fines migration tests were performed using drill cuttings from the formation. The CST test is performed by flowing the proposed base mix water through a pack of crushed formation material to evaluate if any water senstitivites exist within the rock matrix. The CST tests indicated that the rock matrix was not particularily sensitive to the frac mix water with respect to swelling clays. Additionally, fines migration testing was performed to evaluate the presence of mobile clays (such as illite) within the rock matrix. Hot roll testing is performed by placing a known quantity of formation cutting samples into a canister with the proposed fracturing fluid system, including the clay stabilizer. The canister is rolled for 16 hours at expected bottom hole temperatures, and then the cuttings are reweighed after the test to determine the amount of fines released during the test. The results of the hot roll testing are shown in Figure 2, and indicated a fairly strong presence of mobile clays (nearly a third of the sample weight was lost to fines migration without the clay stabilizer). With the addition of a clay stabilizer, the amount of fines released was reduced significantly.

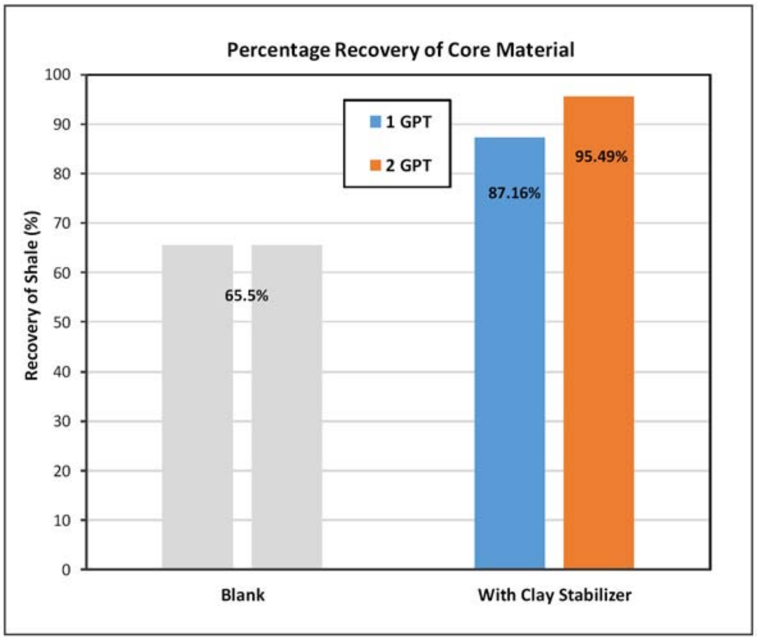

Figure 2—Results of Hot Roll Testing at 180 deg F after 16 Hours

Regain Fracture Conductivity

Laboratory work was performed prior to this project (SPE 185084), and indicated that the HVFR used for this project was capable of providing very high regain fracture conductivities when compared to both linear and crosslinked, guar-based fracturing fluids. Figure 3 shows the results of this work, which indicated that significantly higher regain conductivities could be achieved with the HVFR system when compared to linear or crosslinked fluids. Hybrid-type frac designs, which incorporated both linear and crosslinked gels, were commonly used prior to the start of this project. Since regain conductivity can play an important role in post frac well production, the hope was that the HVFR fluid system could offer well productivity benefits in addition to the cost savings and logistical advantages.

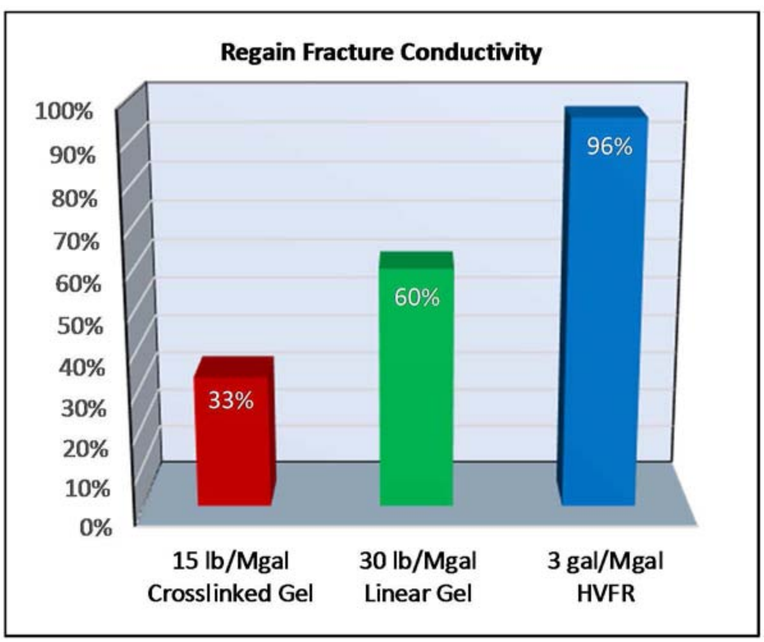

Figure 3—Regain Fracture Conductivity for Various Frac Fluid Systems

Proppant Transport Testing

To evaluate the ability of the HVFR fluid system to effectively transport proppant during the fracturing operations, testing was performed in a laboratory apparatus which simulates slurry flow into a fracture network. Figure 4 shows a photograph of the test assembly. The assembly consists of two parallel plates with a slot width of 0.25 inches, along with secondary and tertiary branches extending from the main slot. For each new branch, the width of the slot is decreased by 50%. A series of tests were performed comparing the HVFR system to a 20 ppt linear guar gel using different sand sizes (100 mesh, 40/70 mesh and 30/50 mesh) at varying sand concentrations (1 to 3 ppg). The results of the testing showed that the sand was transported effectively by the HVFR fluid system as compared to the linear guar gel, with less settling and better distribution of sand within the fracture network.

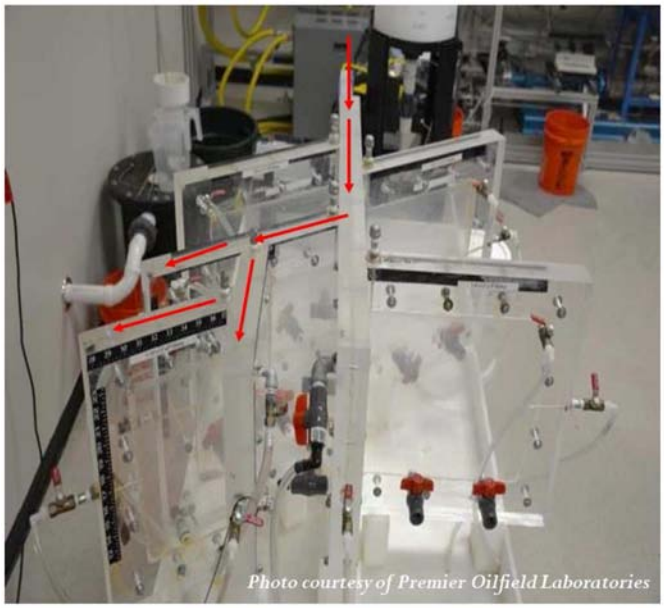

Figure 4—Laboratory Setup for Proppant Transport Testing

The STACK Play

The Mississippian-age STACK play has become one of the premier emerging unconventional plays in the continental United States. Located in Oklahoma within the Anadarko Basin, the newest horizontal target is the Meramec, which lies stratigraphically on top of the Woodford and Osage formations (Figure 5). Multiple landing intervals within the Meramec have enabled operators to target and produce high-volume wells across the play, as well as infill as many as 12 wells in a section, thus far. As seen in Figure 5, the stratigraphic thickness of the Meramec pay zone can vary greatly across the play. As such, optimizing a frac fluid that can reduce costs while generating frac heights upwards of 100' in some sections is a goal of many operators within the play.

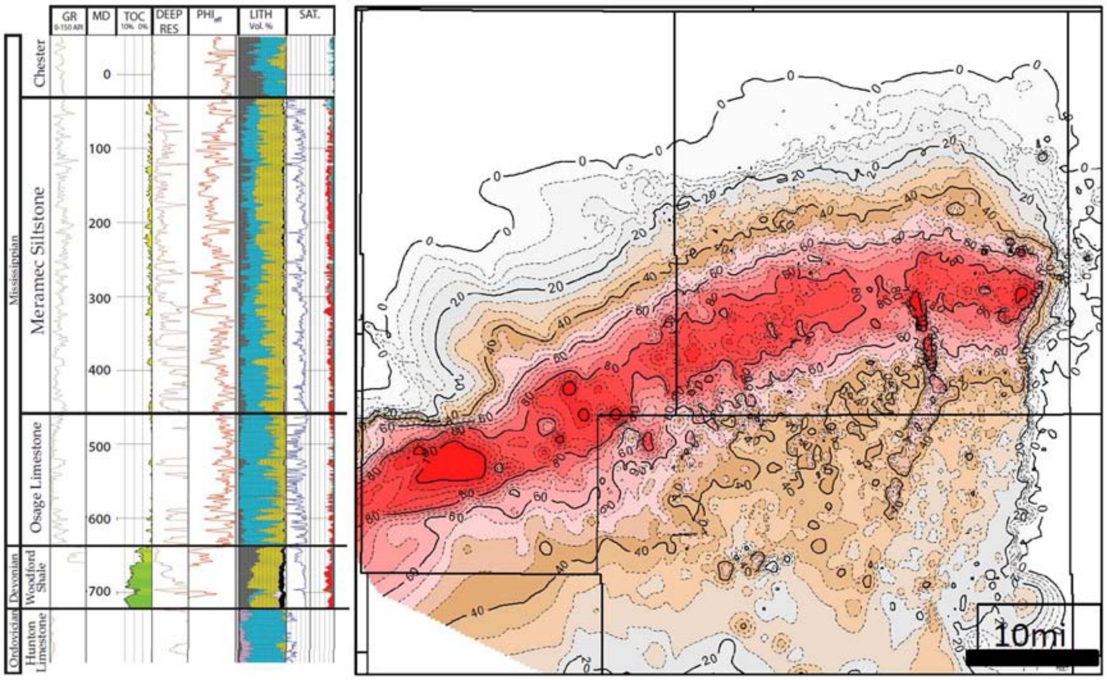

Figure 5—Example isopach thickness of a single Meramac landing layer (Haustveit et al., 2017)

In order to better understand HVFR as a frac fluid within the STACK play, we selected three case studies with different characteristics, such as pay zone thickness, offset well control, or gas-oil ratio within the section. Additionally, all three case studies involved a different stimulation company, to evaluate the cost benefits of the technology as well. The primary goals of the tests were to either create equally productive wells at lower costs, or generate greater productivity from increased conductivity at similar costs to the hybrid design.

Case History 1 - HVFR vs. Hybrid Design in Two Offset Wells

In case history 1, two new parent wells offsetting one another across a leaseline were drilled and scheduled to be completed one after another. Parent wells are the first horizontal wells within their respective section. Both wells were planned to be as similar as operationally possible, with the only exception being fracturing fluid chemistry. Drilling the two wells was a success, with both landed 100% within the target window, and lateral lengths within 4%. The horizontal offset between the wells is approximately 800'. The gross pay within the landing interval for both wells is approximately 125', lying within the primary pay window in the field. These wells were an ideal opportunity to ensure HVFR would create similar fracture heights to access the full pay zone.

The current Devon frac design for the area was implemented on the two wells, which is a hybrid schedule ramping from slickwater to linear gel and finishing with cross-link gel. Two proppants sizes, 100 mesh and 40/70 mesh, are also standard within the design. Well 1 to the west was selected as the control well and completed first, while Well 2 would substitute all gel within the pumping schedule with HVFR and completed second. As seen in Table 2, the volumes between the two wells were kept as similar as possible. Stages, clusters, pump rate and pump design were all held constant between the wells. Stim Company 1 would be completing both wells, and indirectly this created another advantage. All chemicals on the wells were identical, and the lone variable would be substitution of HVFR for gel, both linear and cross-link, and their respective breakers.

Table 2—Stimulation summary of case study 1

	SW MBL	HVFR MBL	18# LIN MBL	18# XL MBL	TOTAL FLUID MBL	100 MESH MM#	40/70 MM#	TOTAL PROP MM#
Well 1	243	0	21	41	305.4	4.7	7.6	12.3
Well 2	251	56	0	0	307.3	4.7	7.6	12.3

Operationally, the wells completed near identically. As seen in Figure 6, average pump rate between the two wells was similar, with the average treating pressure/pump rate (psi/BPM) showing no distinguishable differences between the two designs.

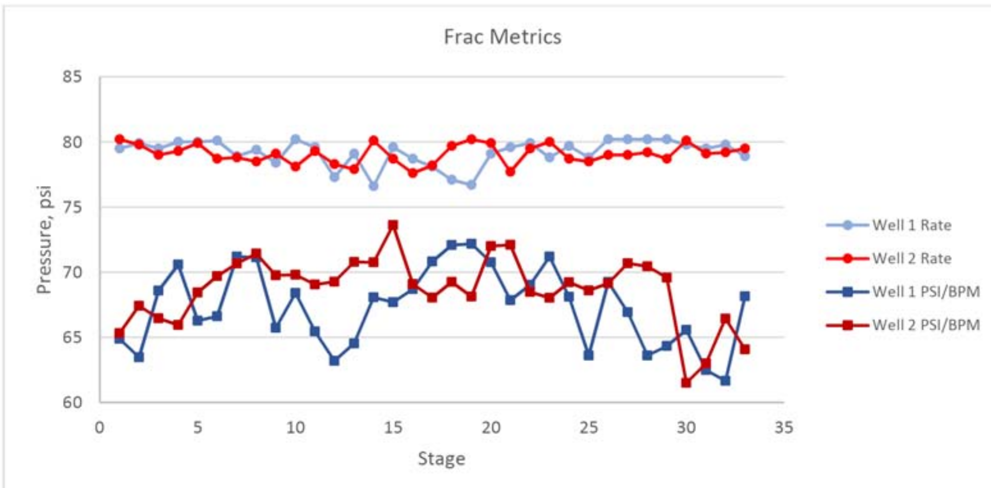

Figure 6—Frac metrics showing similarities of Wells 1 & 2 in case study 1

As previously stated, one operational advantage of HVFR is the ability to reduce concentrations during well operations in an effort to reduce costs. Well 2 had a maximum sand concentration of 5 lbs./gallon, and began conservatively with a corresponding 4 gallons per thousand (GPT) of HVFR. As field personnel became familiar with the product, they began to reduce concentrations to 3.5 and eventually 3.0 GPT while successfully placing all designed proppant. As the standard pump design changes from slickwater to gel, the sand concentration increases and the friction reducer is often cut. As such, three variables are changing downhole, and changes in treatment pressure can be open to interpretation. The field personnel communicated that the HVFR system is easier to pump and optimize due to negligible changes in fluid friction as proppant & HVFR concentration are increased. Due to the chemical cost difference, number of chemicals pumped and the ability to optimize during operations, chemical costs from well 1 to well 2 were decreased by 32%.

After successful sequential drillout operations, both wells were brought online within 24 hours of one another. Similar flowback strategies were also performed on the wells, only differing after 21 days to test well-to-well interference. At this date, Well 2's choke was opened 2/64" while Well 1 was closed 2/64". This was held for one week before returning Well 1 to match Well 2. As seen in Figure 7, the production began to diverge after 30 days, with Well 2 producing at a higher rate than Well 1. This trend continued for the first 100 days of flowback, where Well 2 outperformed Well 1 by 30% on a BOED basis. Understanding the conservative nature of the first test in the play, we deemed case history 1 a success due to the cost reduction, and out-performing the offsetting neighbor.

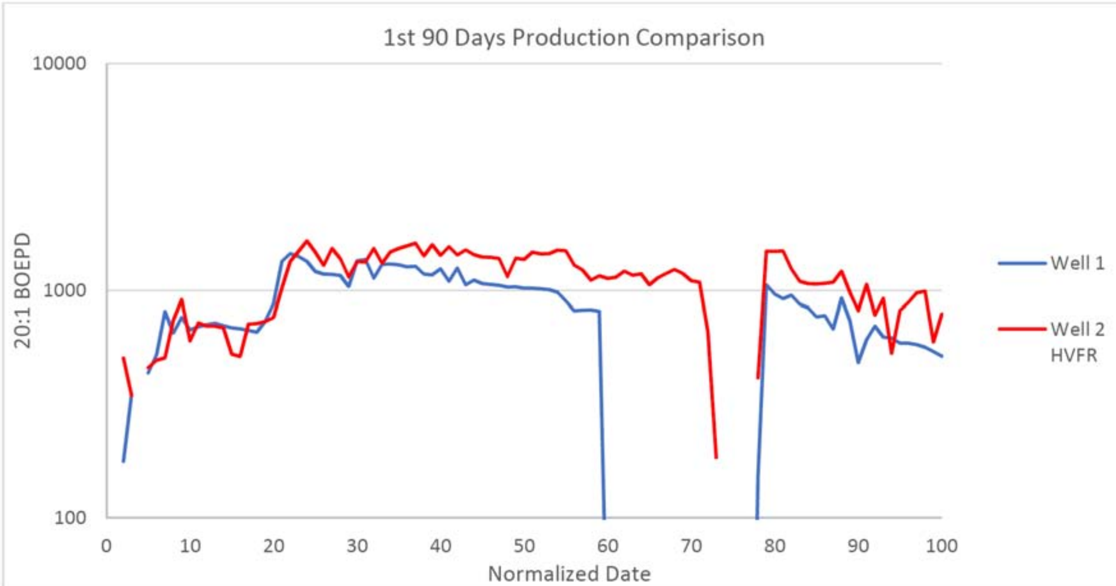

Figure 7—First 100 days production of well 1 & 2 from Case History 1

Case History 2 - Cost Reduction in Thinning Pay

Case history 2 was different in many ways, beginning with geological deposition. A long lateral well was idenfitied on the outer edges of the thinning pay zone within the Meramec as an ideal candidate to test cost cutting technologies in an economically challenged area. The well accessed under 50' of net pay within the landing zone, and frac modeling software predicted the ability to access nearly the full zone with slickwater fluid, similar to the more expensive hybrid-gel design (Figure 8). This helped to eliminate the question of whether or not the fluid could acheieve optimal fracture height, and focus on cost of the fluid as well as regained conductivity during the production period. Lastly, this candidate also benefitted by having several long laterals landed within the same interval in the surrounding area for production comparison purposes. As a parent well with no direct leaseline offsets, this was imperitive in candidate selection to calibrate the results.

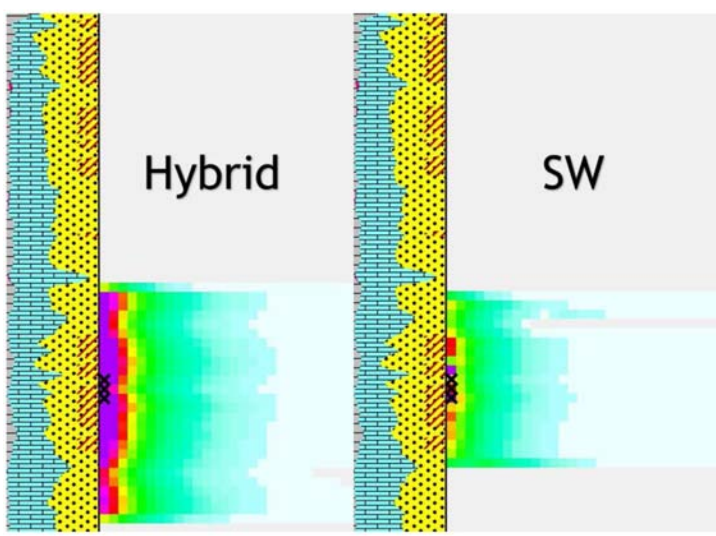

Figure 8—Frac model of case history 2, hybrid and slickwater pump designs

This case was also different in that it used an alternate stimulation company than the previous test, enabling us to substitute the entire HVFR chemical suite in replacement of the vendor's chemicals, as opposed to the friction reducer only. As such, we were able to realize the efficiencies of the system immediately on the surface, where the footprint is decreased due to one fluid, HVFR, taking the place of chemical containers for friction reducer, gel, surface and delayed cross linker, as well as eliminating the need for the gel hydration unit.

Operationally case 2 was another success, getting all stages away successfully to design. Likely due to the thinner pay and geological area, treating pressures were higher, which resulted in more conservative HVFR loadings at 3 GPT. The stimulation contract with Stim Company 2 required a max proppant concentration of 4.0 lb./gallon. This was still very cost advantageous to the previous hybrid design. Even at higher average pressures, the field personnel described the new fracture fluid as an "on-demand chemical," in that the significant decrease in hydration time and viscosity assessment while pumping enabled them to increase the loadings much quicker as pressure necessitated. The hybrid gel pump schedule generated overages in chemicals pumped, due to the longer hydration time. In order to ensure the quality of the viscous fluid was sufficient, gel hydration would begin earlier in the stage and often lead to overpumping of the chemicals. Due to the lower number of chemicals changing, as well as limiting hydration time, the variance between design and actual pumped chemicals on HVFR wells is decreased. As such, chemical cost per stage decreased approximately 33% on case study 2 compared to previous wells with the same stimulation company.

After successful drillout operations, the well was placed on standard flowback operations. After 30 days of production, the case study 2 well was outperforming its direct offsets by 62% on a BOEPD basis, using a 20:1 MCF conversion rate (Figure 9). Due to the nature of the thin reservoir, the longevity of the production will be essential to document and analyze, however case study 2 was also deemed a success.

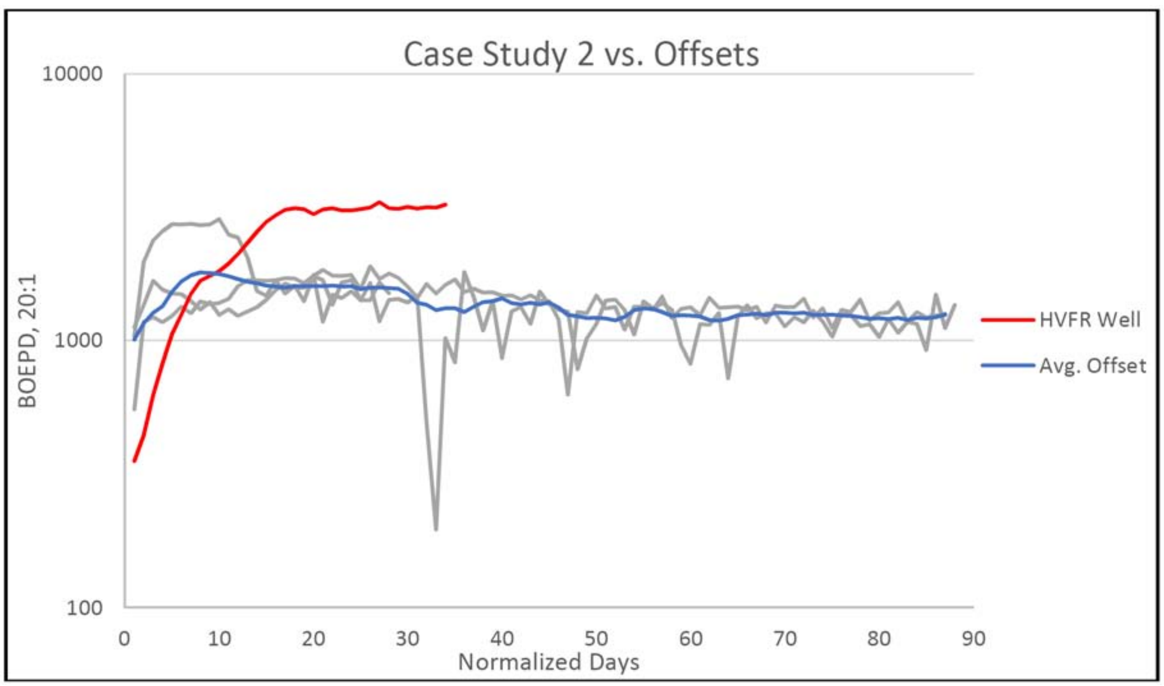

Figure 9—Normalized BOEPD rate of Case Study 2 HVFR Well vs. Offset wells' average (20:1 MCF:BO), using rolling 7 day avg.

Case History 3 - Horizontal Lateral in Geologic Heart of Play

Our third and final case history was selected as a combination between the previous two cases. While geologically more similar to case study 1, lying within a thick pay zone, it was another parent well with consistent results in surrounding sections that would offer reliable production comparisons, similar to case study 2. This well would offer another valuable data point when comparing operational efficiencies, chemical costs, and effectiveness of the fracture fluid both during treatment and flowback. Unfortunately, this well experienced many operational issues, none of which were caused by the fracture fluid, but influenced our success nonetheless.

This well was stimulated with a third stimulation company, providing yet another cost comparison between prior pumped wells across providors. It was also another opportunity to pump the full chemical suite offered, and benefit from the decrease in surface footprint. A new benefit discovered with this stimulation crew was the decrease in liquid additive pumps required at the blender on location. Prior wells had issues maintaining the high number of pumps needed to move all of the chemicals in the hybrid design. By reducing the number of chemicals in the package, less pumps were needed leaving more spare pumps for substitution and maintenance efficiencies. Additionally, the reduced number of chemicals and liquid additive pumps allowed for a tightening in chemical volume variances, leading to a further reduction in chemical costs and ability to meet chemical design more closely.

Operationally, stage-to-stage learnings supported case histories 1 and 2, with a max proppant concentration of 5 lbs./gallon successfully placed with the frac fluid. A new learning in case study 3 was the ability to pump efficiently at higher rates. Due to contractual constraints, case histories 1 and 2 were pumped at an average rate of 70 and 80 BPM, respectively. Case history 3 was able to achieve an average rate of 90 BPM. Field personnel found the HVFR more manageable in adhering to design at higher rate, as previously they would often need to drop rate or extend the slickwater portion of the pump design if there were any delays in gel hydration or quality. As such, the HVFR stages were able to be completed in a faster time, decreasing both the pumping charge per stage, as well as the number of days to complete the well. Similar to case histories 1 and 2, the chemical cost savings on this well averaged 38% (Table 3).

Table 3—Chemical cost reduction for each case history HVFR well

Case History	1	2	3
Chemical Cost Savings	32%	33%	38%

Even with chemical cost savings comparative to our other case histories, these advantages were not fully realized, as numerous operational issues limited the ability to deem this case history a success. Mechanical issues during pump down operations left one spent gun string downhole. After the completion of the well, this string proved difficult to recover and resulted in only 10 of 32 stages being successfully drilled out and able to flow without further intervention.

As seen in Figure 10, the well produced initially at competitive rates, but as expected has shown earlier decline than the offsets. As such, further diagnostics are needed to evaluate the productivity of the shortened productive lateral. Comparing reservoir productivity and production of the well and its offsets, normalizing per productive lateral foot will allow for proper understanding of the performance of HVFR as a fracture fluid in this case study. Using this information, in addition to the chemical cost savings during stimulation, generated a positive outlook on the case study, bearing in mind the unfortunate operational difficulties.

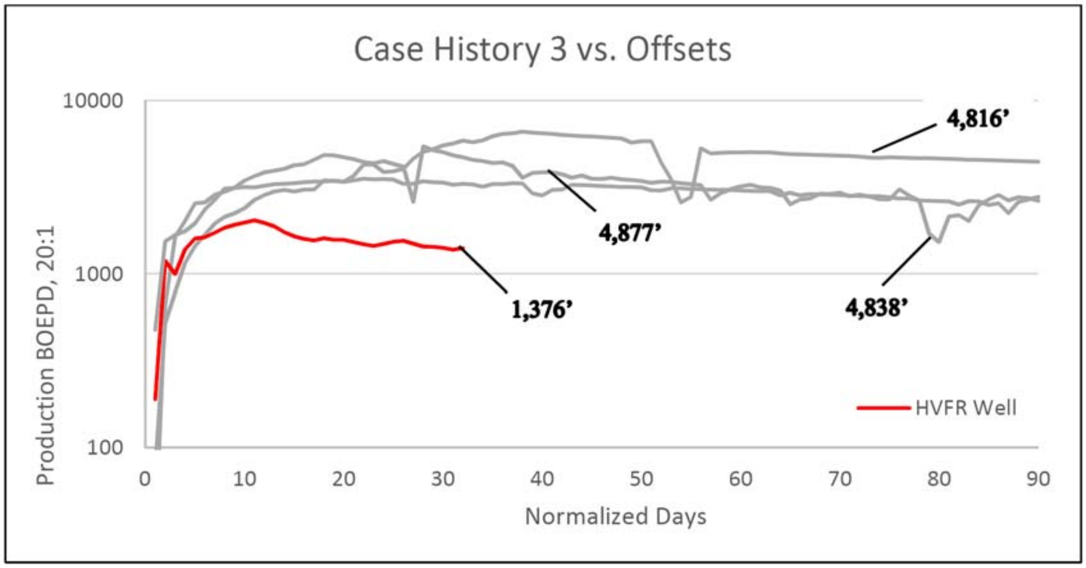

Figure 10—Normalized BOEPD rate of Case Study 3 HVFR Well vs. Offset wells' average (20:1 MCF:BO), with gross perforated interval noted.

Conclusions

In the creation of the candidate selection for testing HVFR as a fracture fluid, 3 goals were identified: operation efficiencies during fracture operations, chemical cost reduction, and production improvement due to increased regained conductivity. Selection of three candidates, with various offset well control, pay thickness, and stimulation vendor, created a valuable data set.

Operational efficiencies were experienced on all three case studies, reducing concentrations of HVFR stage to stage by field personnel and engineers. Further, reducing the surface footprint, the number of pumps needed, and the number of fluid changes during the pump design allowed for less down time and variance between planned and actual designs. Creating a more efficient design by replacing multiple chemicals with a single one, combined with cost advantages of the fluid, allowed for an average reduction of chemical costs by 34%. After analyzing post job reports, it is believed that additional testing could result in further cost reduction. Lastly, early production during the flowback period of the wells shows promising results compared to offset wells within similar rock. While the regained conductivity benefits could be favorable both near and long term in the productive life, combining cost savings with improved early time productivity has promoted the selection of more candidates for continual testing as the play develops. Whether judging by field operations, cost cutting ability, or production enhancement, early results showcase high viscosity friction reducers as a successful fracturing fluid in the STACK play and require further testing and development in the field.

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