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Applications of Viscosity-Building Friction Reducers as Fracturing Fluids

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Abstract

The use of viscosity-building friction reducers (VFR) as fracturing fluids is increasing in the industry today (Motiee et al. 2016; Sanders, et al. 2016; Al-Muntasheri, et al. 2014, Holtsclaw, et al. 2010). In addition to providing pipe friction reduction during fracturing treatments, these systems develop elevated viscosity over traditional slickwater fluids to provide several advantages described herein. Additionally, using advances made in polymer chemistry such as fit for purpose monomer structures and effective breakers, VFR fluids exhibit high regain conductivities compared to linear and crosslinked gels and are being used as a direct replacement for these conventional guar-based systems.

The polyacrylamide-based VFR system described in this paper has been used on over 10,000 stages in multiple basins since 2014. Some of the potential advantages VFR fluids offer include lower cost, reduced water requirements compared to conventional slickwater treatments, fewer chemicals and equipment on location, on-the-fly design change flexibility, and high fracture conductivities. This paper will present three case histories from projects performed recently to demonstrate these advantages.

Background

Fracturing strategies employed by operators in unconventional reservoirs often include a combination of two objectives; develop as much fracture complexity and surface area contact as possible during the early stages of the treatment, followed by increasing the conductivity of the fracture network in the near wellbore and intermediate fractured region to sustain high production rates. With that strategy, fracture treatment pumping schedules often incorporate the use of small mesh sand (ie; 100 mesh) in the early stages of the job followed by higher concentrations and/or larger sizes of proppant in the later stages. Fracturing fluids required to achieve these objectives often include slickwater followed by a higher viscosity fluid for the later stages, which requires the use of two or more fluid types to be used during the job. VFR fluid systems allow for the entire pumping schedule (apart from any acid) to be executed with a single fluid type. Viscosity increases are simply controlled by the addition of the VFR polymer.

The use of polyacrylamides (PAM) is widespread both outside and within the oil and gas industry. Due to its ability to flocculate solids in a liquid, PAM are used extensively in processes such as water treatment and paper making. In the oil and gas industry, PAM systems have been used for many years in applications such as clay control during drilling, acid gelling agents and enhanced oil recovery (EOR) methods. In drilling

operations, a class of water-based muds use partially-hydrolyzed polyacrylamide (PHPA) as a functional additive, either to control wellbore shales or to extend bentonite clay in a low-solids mud (Clark, et al. 1976). In acid stimulation treatments, PAM are used over a wide temperature range to facilitate acid placement through their viscosity development (Norman, et al. 1984; Crowe, et al. 1980). During EOR operations, PHPA are commonly used in polymer flooding to displace hydrocarbons and enhance field production (Ryles, et al. 1986). These applications of polyacrylamides require good fluid stability under a variety of harsh conditions, and often incorporate high molecular weight systems to achieve that stability.

High molecular weight PAM, such as those used for the applications above, are not commonly used for fracturing applications due to their stability and low regain conductivity. However, as PAM began to be used for friction reducers in fracturing applications, monomer chemistries evolved to create lower molecular weight systems that are cleaner than not only the earlier PAM systems, but also cleaner than the guar and modified forms of guar gelling agents used in the fracturing industry today (StimLab 2012).

Justifications for VFR Fluids

Some of the advantages VFR systems can offer when compared to other fluid types such as slickwater, linear, and crosslinked gels are summarized below. The advantages can be categorized through cost reduction, operational efficiencies, physical properties, and fracture placement advantages via higher conductivities and on-the-fly design change capabilities.

Cost Reduction and Simplified Logistics

By using a single fluid system that can be adjusted to provide a range of viscosities, fewer chemicals are required on location, simplifying logistics and reducing tank requirements for the operation. Motiee (Motiee et al. 2016) reported overall chemical volume reductions from 33-48% when switching to a VFR fluid. Due to higher proppant concentrations the VFR fluid can transport, water volume requirements can be reduced by 30% or more to place a given proppant volume when compared to slickwater treatments.

Another area of cost reduction is with the actual cost of the materials themselves. Although difficult to quantify due to market conditions, several operators have reported lower overall chemical costs when switching from hybrid or crosslinked fluids to the VFR system. Earthstone Energy, Inc (Case History 2 in this paper) reported overall completion cost reductions of 35%, of which 17% were observed in pressure pumping charges.

Finally, cost savings arise with the potential for less fracturing equipment required on location. Gel hydration units or dry gel handling equipment is not required because of the rapid hydration rate of the VFR polymer. Also, with the friction reducing properties of the VFR fluid, pumping pressures and therefore hydraulic horsepower requirements are lower than those while pumping crosslinked gels at similar rates. Figure 1 shows the friction reduction obtained with the VFR fluid system at various concentrations of FR loading. The test is started by pumping fresh water through a laboratory flow loop consisting of 3/8" diameter piping. The fresh water exhibits high differential pressure as shown at the start of the test. As FR loading in the water is increased to 0.5 gpt, significant friction reduction in the range of 70% occurs. As the concentration of FR is progressively increased from 0.5 gpt to 3 gpt, thus increasing the fluid viscosity, only a slight decrease in friction reduction occurs, from 70% down to about 60% at 3 gpt of FR loading.

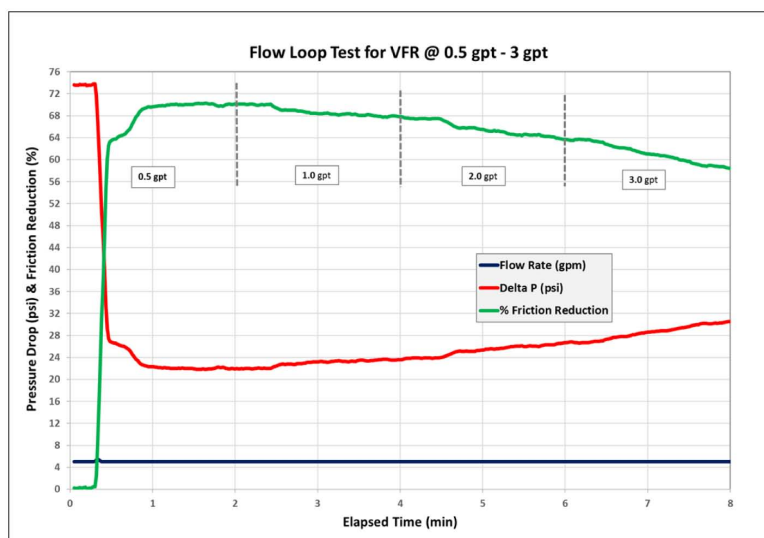


Figure 1—Friction Reduction of VFR Fluid at Various Concentrations using Flow Loop

Viscosity Development at Low Concentrations

Although some VFR fluids currently available in the industry require higher concentrations to achieve significant viscosity, the VFR system described in this paper yields elevated viscosities at relatively low concentrations using a complex branching structure of the monomer. Figure 2 shows baseline viscosities obtained with the low concentration VFR system run at 3 gpt concentration. The lowered polymer loadings provide for a cleaner and more cost-effective system. The data in Figure 2 also shows that clean breaks can be achieved, even at low temperatures, using a liquid breaker that has been developed with the system. While the VFR performs best in mixing waters with low hardness levels, viscosity development can be obtained in a variety of water types, usually with reduced viscosity when compared to cleaner water sources.

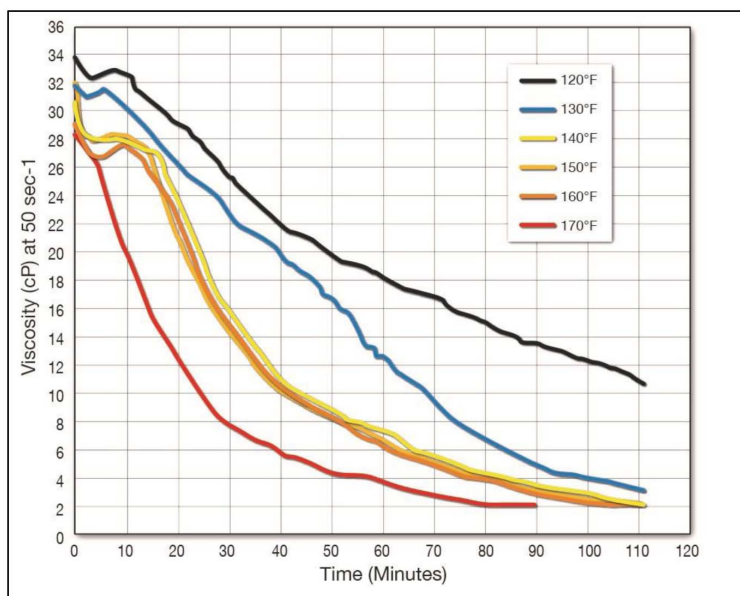


Figure 2—Viscosity Profiles of VFR Fluid @ 3 gpt FR Concentration and 1 gpt Breaker

High Fracture Conductivities

When compared to currently-used fracturing fluids such as slickwater, linear and crosslinked gels, the VFR fluid can provide higher fracture conductivities through different mechanisms. First, since higher

proppant concentrations can be transported and placed with a viscosified fluid, higher fracture conductivities can be achieved over low viscosity slickwater fluids. Secondly, when compared to linear and crosslinked gels, higher retained fracture conductivities are observed with the VFR system. For example, the retained conductivity study conducted by StimLab in 2012 showed that even at a very high FR concentration of 14 gpt, a VFR fracturing fluid provided 15-20% higher retained conductivity than a 30 lb/Mgal linear guar gel. Table 1 shows retained conductivity data from an independent laboratory (PropTester 2016) comparing a 15 lb/Mgal crosslink guar fluid system with the VFR system at 3 gpt concentration under the same test conditions. The final retained conductivity of the crosslinked fluid was 36% compared to 106% for the 3 gpt VFR fluid.

Table 1—Retained Conductivity of 15 lb/Mgal Crosslinked fluid vs. 3 gpt VFR fluid (Test Conditions were 180 °F with 2 lb/sq. ft. 30/50 Sand)

Retained Conductivity of 15 lb/Mgal Crosslinked Gel with Breaker

Stress, psi	Time @ stress	Time (Total)	Conductivity (md-ft)	Permeability (Darcy)	Width (in)	% Regain
1,000	24 hrs.	24 hrs.	2692	131	0.246	
2,000	0 hrs.	24 hrs.	173	9	0.242	8
2,000	24 hrs.	48 hrs.	709	35	0.240	33
2,000	50 hrs.	50 hrs.	752	38	0.239	36

Retained Conductivity of 3 gpt VFR Fluid with Breaker

Stress, psi	Time @ stress	Time (Total)	Conductivity (md-ft)	Permeability (Darcy)	Width (in)	% Regain
1,000	24 hrs.	24 hrs.	2668	130	0.246	
2,000	0 hrs.	24 hrs.	2031	100	0.243	93
2,000	24 hrs.	48 hrs.	2241	111	0.243	104
2,000	50 hrs.	50 hrs.	2242	111	0.243	106

On-the-fly Design Changes

Since the VFR system is run as a liquid additive on-the-fly, viscosity changes can be made whenever required during the job. For example, on-the-fly viscosity adjustments might be made to 1) lower the FR loading if the job is proceeding with no problems to reduce chemical volumes and cost, 2) increase the viscosity to facilitate on-the-fly decisions to place higher proppant concentrations or larger proppant volumes than originally designed, or 3) help mitigate the effects of "tight spots", or areas of fracture width restrictions in which a higher viscosity helps to move proppant beyond those points. The third case history in this paper describes how issues with tight spots were mitigated using viscosity adjustments.

Case Study 1 – Eagle Ford, Karnes County, TX.

Background

The Eagle Ford Shale, one of the most active unconventional reservoirs in the US, began development in 2008. Substantial liquids production, along with solution gas, has heightened interest and helped to accelerate development in this play. The characteristics of the Eagle Ford change substantially across the southwest-to-northeast strike of the play (Figure 3). Shale thickness ranges from 45 feet to more than 500 feet with an average of about 250 feet across the play. The true vertical depths of the producing intervals are found at depths between 4,000 and 14,000 feet. Pressure gradients, total organic content and mineralogy also vary significantly. The Eagle Ford shale is a transitional shale with facies exhibiting both brittle isotropic properties and ductile anisotropic properties. In general, transitional shales respond well to a hybrid type fracturing treatment utilizing a low viscosity fluid early on to promote fracture complexity and a higher viscosity fluid in the later stages to prop open the main fracture wings.

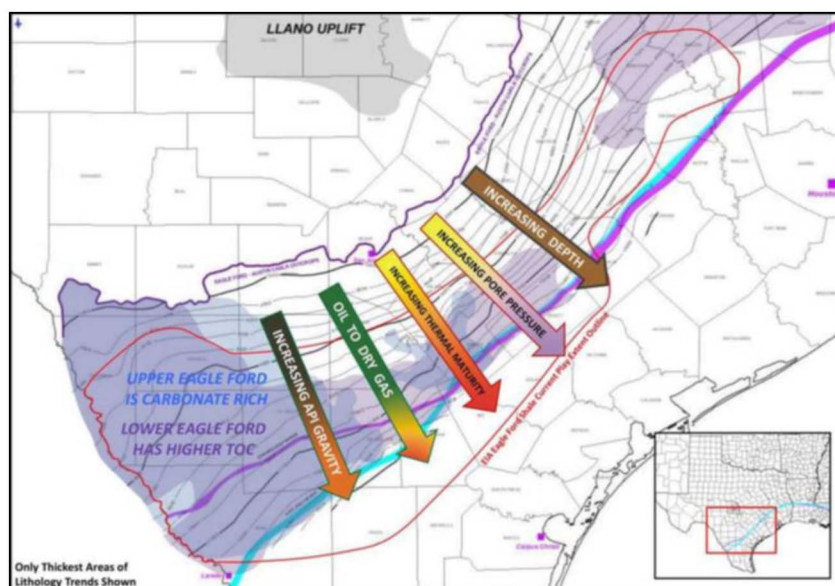


Figure 3—The Eagle Ford properties change significantly across the play

The well described in this case is located in the south-central part of Karnes County, TX. Two large faults were crossed while drilling to the final lateral length of 5,705 feet, leaving portions of the wellbore in the overlying Austin Chalk. The average true vertical depth of the target zone was 10,624 feet with a bottom hole temperature of 265 °F. Total thickness of the Eagle Ford in this area averages about 185 feet.

Frac Design and Execution

The main goals during the treatment design were to create complexity with the use of a small mesh size sand, transport proppant into the fracture network and create a sand bank in the near wellbore region. The sand bank is an important aspect of the completion as sand banking mitigates proppant pack damage mechanisms by allowing fluid flow through higher conductivity flow channels. For this project, 100 mesh sand was used with the intention of propping open some of the narrow, far field fractures. The proppant selected to create the sand bank in the near wellbore region was 30/50 Premium White sand.

When focusing on the fluid selection for this project, data mining was initially used to determine how the Eagle Ford was responding to different treatment types. Maximum monthly production rate was compared to the fluid type across the entire play and is shown in Figure 4. The data from this study revealed that wells throughout the play (as well as those in Karnes County) that were completed using crosslinked fluids and hybrid fluid designs were outperforming those being completed with slickwater.

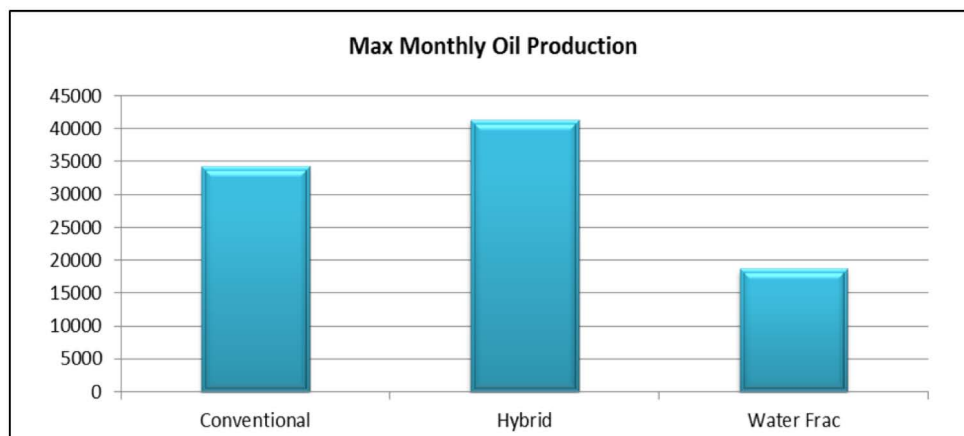


Figure 4—Comparison of Eagle Ford production rates vs. frac fluid type

Historically, the fluid selection of choice for this operator was a 35# borate crosslinked gel system. For this project, however, the operator chose to use the VFR fluid system to reduce chemical costs, simplify operations, and to place comparable proppant volumes to the crosslinked fluids without the damage mechanisms caused by gel residue. A nano surfactant was also selected to reduce the capillary pressures within the producing facies.

Figure 5 shows a plot of one of the frac stages from this well. Although not shown on the plot, the FR concentration was run at 0.5 gpt for the first portion of the job, and then increased in the same increments as the proppant concentration (ie; at 4 ppg proppant concentration, the FR loading was 4 gpt). This step-wise increase in FR loading as the job progresses is commonly used with this system. The VFR system allowed for the 100 mesh sand to be transported deeper into the fracture system and for high proppant concentrations to be placed, while at the same time allowing for the potential of the sand bank to form in the near wellbore region.

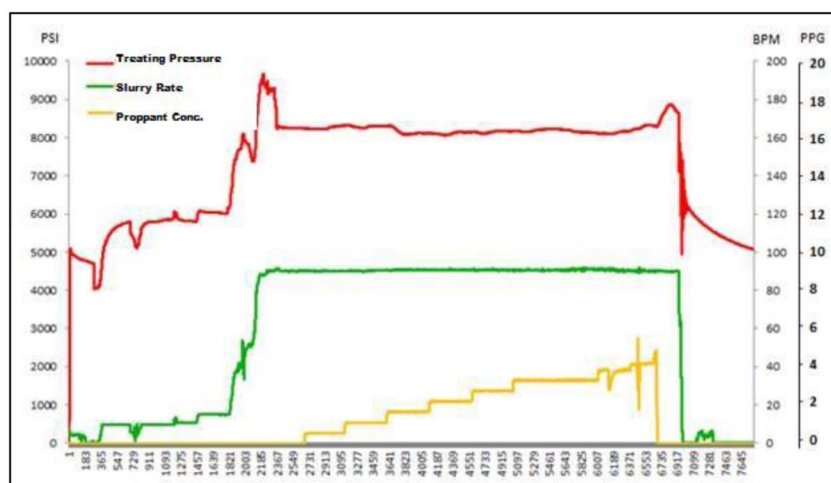


Figure 5—Frac Plot of VFR treatment in Karnes County, TX

Production Results

Figure 6 shows the early time production rates for this well during the flowback test. The actual total fluid rate on a 32/64 choke outperformed expectations, which was projected to be about 2,800 barrels of fluid per day at 1,200 psi flowing pressure. The actual total fluid rate was approximately 6,700 bfpd at 1,960 psi flowing pressure, with an oil rate of 2,600 bopd and a gas rate of 1,200 mcf/d. After thirty days of production

the well continued to outperform offset wells in the area flowing at a total fluid rate of 1,590 bfpd, with an oil rate of 995 bopd and a gas rate of 635 mcf/d.

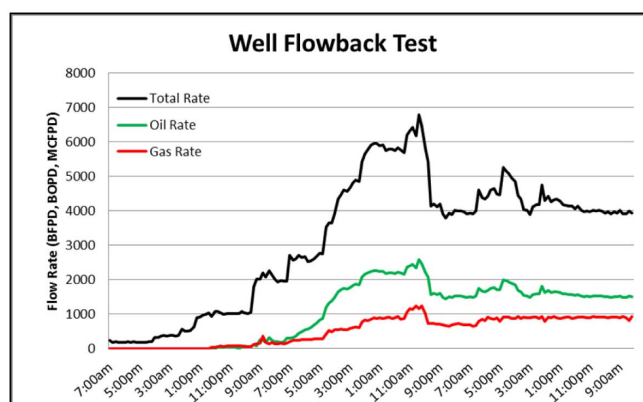


Figure 6—Well production response during flowback test with results exceeding expectations

Case Study 2 – Eagle Ford, Fayette County, TX.

Background

Earthstone Energy, Inc owns and operates assets in the Eagle Ford, Midland, and Williston basins. In the Eagle Ford, 18,600 net leasehold acres exist in Fayette, Gonzalez, and Karnes counties (see Figure 7). Earthstone's production in the Eagle Ford has grown from about 2,000 BOE/day in January of 2014 to over 6,400 BOE/day in November 2015. This case describes the application of the VFR fluid system on two wells near Flatonia, TX in Fayette County within the Eagle Ford play.

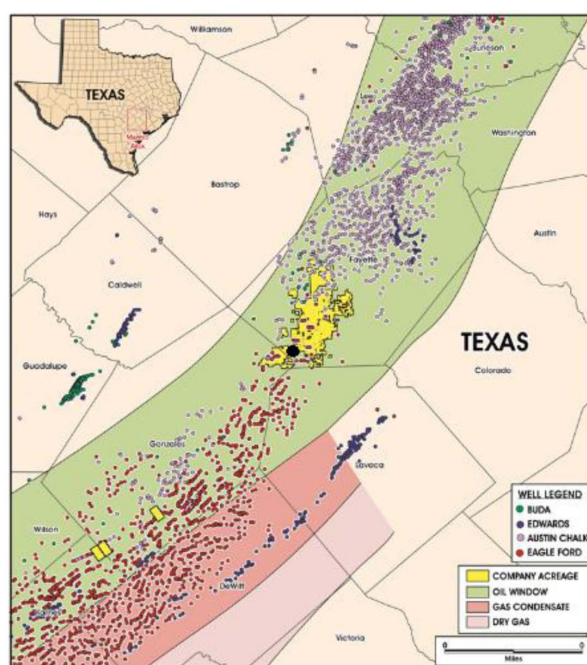


Figure 7—Earthstone acreage in the Eagle Ford (in yellow), with Flatonia Townsite area (black symbol).

The targeted Eagle Ford formation lies directly below the Austin Chalk and directly above the Buda Lime formations. Fayette county is in the northern, liquids-rich region of the Eagle Ford where the Eagle Ford is not as thick or thermally mature as other areas. Previous production in the Flatonia Townsite area has

created some degree of pressure depletion compared to the other areas of comparison (described further below). Furthermore, a somewhat lesser degree of natural fracturing exists in the Flatonita Townsite area, contributing to what is believed to be lower overall reservoir quality than the comparative wells.

Earthstone's frac fluid selection has evolved since 2012, when hybrid designs were originally used to increase the amount of proppant placed during each frac stage. During 2014-2015, the frac fluid design was switched from hybrid to fully crosslinked fluids. Using this approach, positive production results were observed, but lowering oil prices mandated a need for lower cost completions. In 2016, Earthstone switched to a VFR system with the goals of 1) creating more fracture complexity using a less viscous fluid system, 2) placing similar proppant volumes as previous hybrid and crosslink designs, 3) reducing completion costs, 4) simplifying operations, and 5) achieve production results comparable to or greater than previous designs.

Frac Design and Execution

The generalized frac design strategy employed by Earthstone in this area is to develop a significantly complex fracture network during the early portions of the treatment, followed by packing of the fracture network with larger sized, and higher concentrations of proppant. To accomplish this strategy on the two study wells, a low concentration of VFR (ie; slickwater) was used for the first portion of the job to encourage complexity development, followed by increasingly higher viscosities of the VFR fluid to transport higher proppant concentrations and pack the fracture network during the later stages of the treatment. The perforating strategy employed consisted of five clusters spaced at 40 ft. A tapered perforation strategy, with fewer heel-side shots and more toe-side shots, was employed to promote higher cluster efficiency.

Table 2 shows an example pumping schedule used for the wells in which the VFR fluid was employed. A total of 532,500 lbs of proppant was designed with no screenouts occurring on any of the stages. As can be seen in Table 2, the FR loading for the first four stages of the job (after acid) was 0.5 gpt of the VFR fluid. During stage 7, when the sand concentration reached 1 ppg of 100 mesh, the VFR concentration was increase to 1 gpt, and systematically raised from 1 gpt to 2.5 gpt throughout the remaining proppant stages.

Table 2—Pumping schedule for VFR frac treatments on Earthstone wells

Stage #	Description	Fluid Type	Conc. (PPA)	FR Conc. (gal/M)	Stage Liquid Volume (GAL)	Stage Liquid Volume (BBL)	Cum. Liquid Volume (GAL)	Cum. Liquid Volume (BBL)	Prop. Type	Stage Prop. Mass	Cum. Prop. Mass	Pump Rate	Stage Time
1	Load Well	Slik-Vis VFR			1000	24	1,000	24		0	0	10	2.4
2	15% HCL	Slik-Vis VFR			3,000	71	4,000	95		0	0	10	7.1
3	Pad	Slik-Vis VFR		0.50	40,000	952	44,000	1,048		0	0	72	13.2
4	0.25 ppg 100 Mesh	Slik-Vis VFR	0.25	0.50	30,000	714	74,000	1,762	100 Mesh	7,500	7,500	72	9.9
5	.5 ppg 100 Mesh	Slik-Vis VFR	0.50	0.50	30,000	714	104,000	2,476	100 Mesh	15,000	22,500	72	9.9
6	.75 ppg 100 Mesh	Slik-Vis VFR	0.75	0.50	30,000	714	134,000	3,190	100 Mesh	22,500	45,000	72	9.9
7	1.0 ppg 100 Mesh	Slik-Vis VFR	1.00	1.00	30,000	714	164,000	3,905	100 Mesh	30,000	75,000	72	9.9
8	1.25 ppg 100 Mesh	Slik-Vis VFR	1.25	1.00	35,000	833	199,000	4,738	100 Mesh	43,750	118,750	72	11.6
9	1.5 ppg 100 Mesh	Slik-Vis VFR	1.50	1.50	35,000	833	234,000	5,571	100 Mesh	52,500	171,250	72	11.6
10	1.75 ppg 100 Mesh	Slik-Vis VFR	1.75	1.50	35,000	833	269,000	6,405	100 Mesh	61,250	232,500	72	11.6
11	2.0 ppg 100 Mesh	Slik-Vis VFR	2.00	2.00	35,000	833	304,000	7,238	100 Mesh	70,000	302,500	72	11.6
12	1.5 ppg 40/70 Mesh	Slik-Vis VFR	1.50	2.00	40,000	952	344,000	8,190	40/70 Mesh	60,000	362,500	72	13.2
13	1.75 ppg 40/70 Mesh	Slik-Vis VFR	1.75	2.50	40,000	952	384,000	9,143	40/70 Mesh	70,000	432,500	72	13.2
14	2.0 ppg 40/70 Mesh	Slik-Vis VFR	2.00	2.50	27,000	643	411,000	9,786	40/70 Mesh	54,000	486,500	72	8.9
15	2.0 ppg 30/50 Mesh	Slik-Vis VFR	2.00	2.50	11,500	274	422,500	10,060	30/50 Mesh	23,000	509,500	72	3.8
16	2.5 ppg 30/50 Mesh	Slik-Vis VFR	2.50	2.50	9,200	219	431,700	10,279	30/50 Mesh	23,000	532,500	72	3.0
17	Flush	Slik-Vis VFR			15,000	357	446,700	10,636		0	532,500	72	5.0

Figure 8 shows a plot of the fracturing treatment during one of the stages. During the early portions of the job, several large pressure fluctuations occurred which was an indication of additional perforation clusters breaking down and/or additional fracture surface area being created; both of which were a core part of the frac design strategy. For the remaining portion of the treatment, pressure followed a downward trend and

then began a slow build-up indicating stable fracture geometry growth followed by packing of the fracture network. At several points during the later stages of these treatments, the FR concentration was adjusted as needed to facilitate the desired placement strategy.

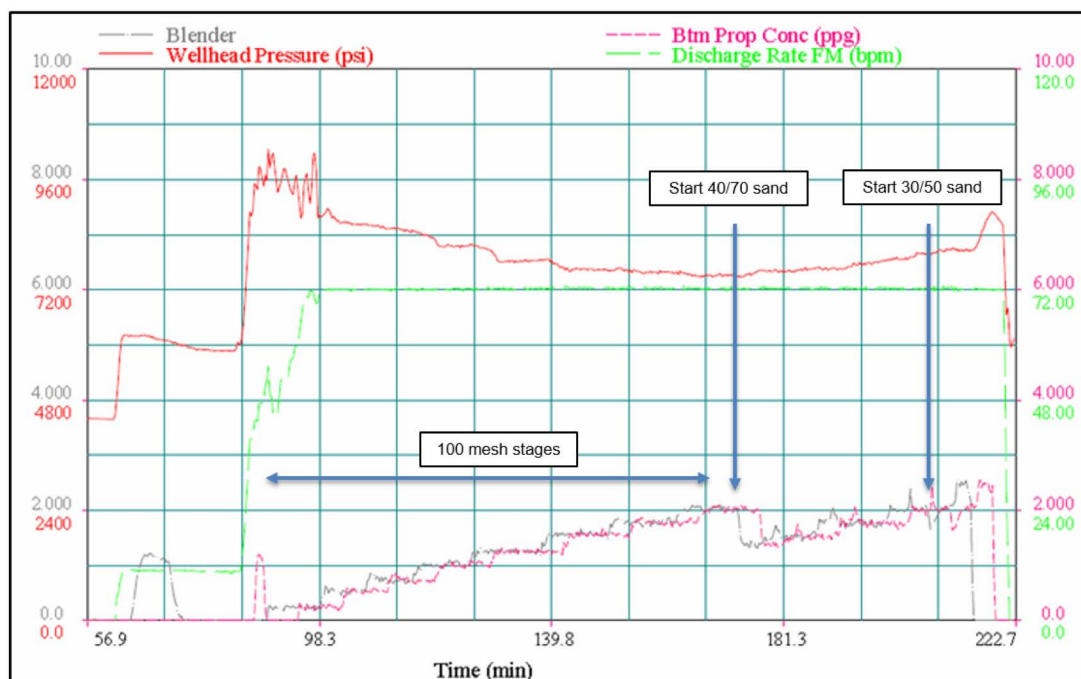


Figure 8—Fracture Treatment plot from Earthstone well using VFR fluid

Production Results

Production data from Flatonia Townsite wells in which the VFR fluid was used is shown in Figure 9 as cumulative oil produced to date, normalized to the length of the lateral. Figure 9 shows that the Townsite wells have currently produced more oil after 30 days, under similar managed choke conditions, than the other wells in the area. The production results are encouraging as the original goal was to reduce completion costs without observing a significant decline in production. Since making this transition to the VFR fluid system, completion costs for Earthstone have been reduced by 35%. With the cost reductions and positive production results observed, the fluid system is now being used in other areas.

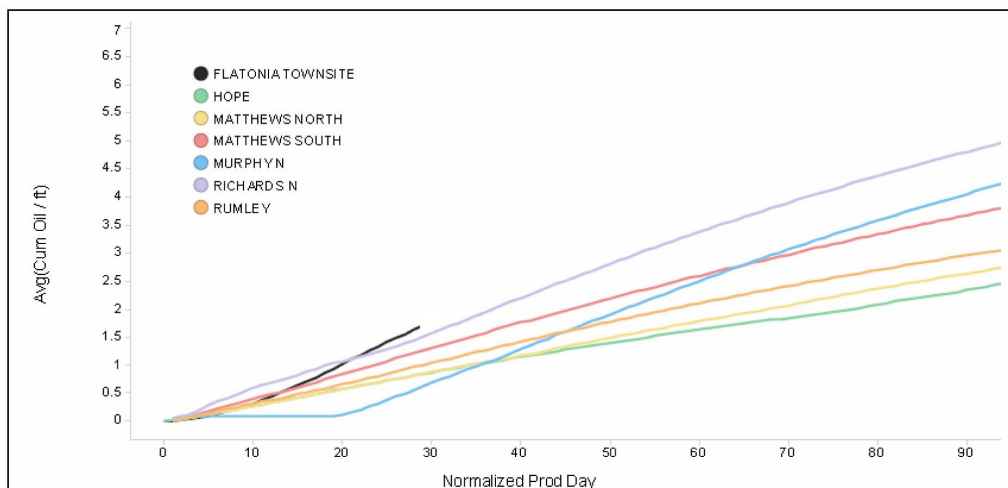


Figure 9—Production data (normalized to lateral length) from Earthstone areas, with Flatonia Townsite VFR wells

Case Study 3 – Wolfcamp and Spraberry Formations, Permian Basin, TX.

Background

This Permian operator owns oil-focused assets within both the Delaware and Midland basins (Figure 10), with much of their activity conducted in Glasscock, Martin and Reeves counties. With multiple reservoir targets in both basins, a significant variation in formation characteristics exist from well to well across the development areas. This variation in formation properties, combined with differences in frac completion designs and objectives for the different areas, historically led to the use of several different fluid systems which complicated logistics and pumping operations. The VFR fluid system was ultimately chosen for its versatility to facilitate any of the frac design requirements.

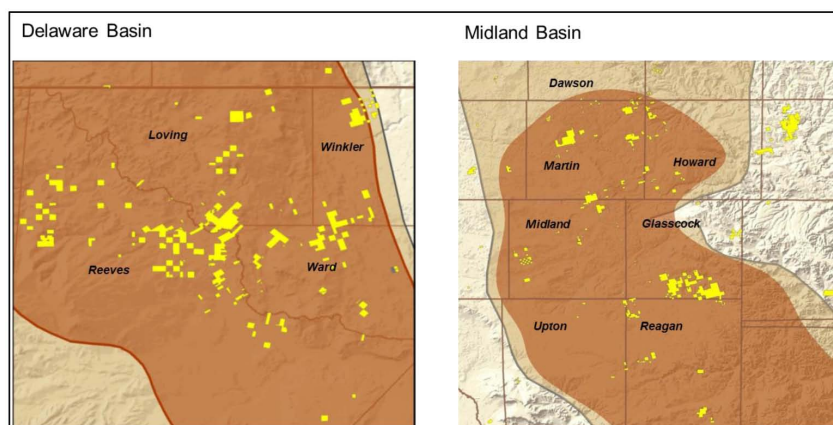


Figure 10—Asset locations for Permian operator in Case 3

Reservoir Characteristics

The lithology of the Delaware Wolfcamp is analogous to the Midland Wolfcamp, characterized by interbedded shale and limestone. Figure 11 shows an example of the target formations encountered in the Delaware Basin for this project. With over 600 feet of potential target pay within the Wolfcamp A and B formations, and significant lithology variation throughout the potential target intervals, many scenarios exist with regards to where to land laterals, selection of target interval for stimulation, offset well distances (both vertically and laterally), and other considerations. For the Spraberry targets in the Midland Basin (not shown in Figure 11), multiple targets also exist over several hundred feet and similar factors are considered during the well placement and completion design process.

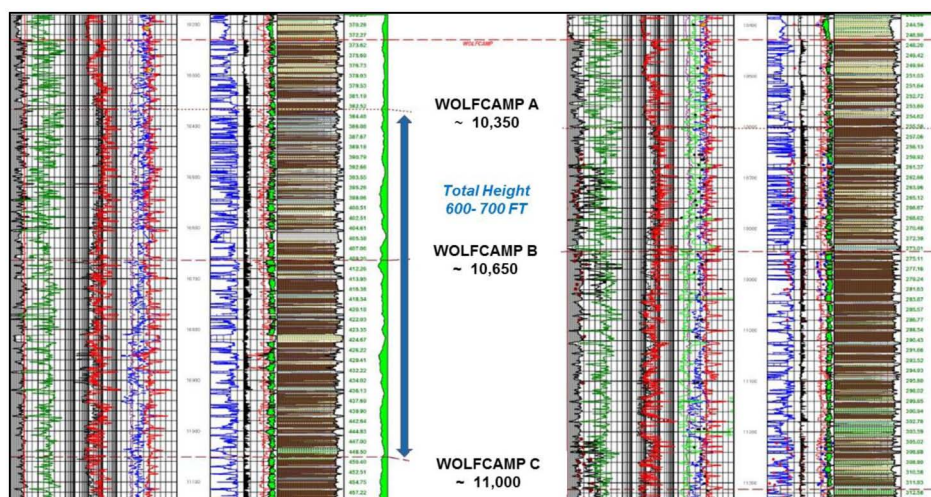


Figure 11—Wolfcamp log section from the Delaware Basin showing 600-700 feet of potential target formations

Frac Design and Execution

As mentioned, the frac design strategy for this project varies from area to area, but can generally be summarized as follows:

- In smaller or more contained formation sections, ensure that a complex fracture network is obtained to maximize reservoir contact
- In areas of tighter well spacing, control fracture length growth to mitigate the risk of frac hits and well interference on offset wells
- In thick reservoir sections, ensure that as many layers are stimulated as possible
- For all designs, ensure placement of a designed amount of proppant volume per foot of lateral length

This operator selected to use the VFR fluid for its flexibility to assist in achieving any of the frac design strategies mentioned above. Low concentrations of the FR can be used to create complexity, while higher concentrations will yield viscosities that enable the placement of higher fracture conductivities and help to provide larger fracture heights.

The ability to reduce well to well frac hits and interference is a targeted objective for this operator. In one area, well spacing varied from about 400 feet in one portion of the reservoir, to well spacings of 600-800 feet in adjacent areas. By using the fluid system to adjust total fluid volume pumped, while maintaining the placement of similar proppant volumes in each well, potential issues with well interference are believed to have been reduced.

As mentioned earlier in this paper, on-the-fly adjustments to viscosity can be made using the VFR system. Figure 12 shows a job plot from a Delaware Wolfcamp well for this project. Lower FR loadings were used for the placement of the early time 100 mesh stages and lower concentrations of 20/40 mesh sand, followed by progressively increasing the FR loading from 0.75 gpt to 2.5 gpt to place the 20/40 stages. During this treatment, two notable pressure increases occurred. The first, corresponding to a time just after 60 minutes on Figure 12, pressure began to rise which resulted in a decision to increase the FR loading for the fluid system. Shortly after the FR loading was increased, pressure rolled over and began to drop. Similarly, pressure began rising rapidly (perhaps due to a fracture width restriction) between time 70-80 minutes which again prompted an increase in the FR concentration. At a time of 80 minutes, another pressure "rollover" occurred, perhaps facilitated by the higher fluid viscosity. The remainder of the treatment was placed without issues. On-the-fly viscosity adjustments such as those described above are simple to perform on location.

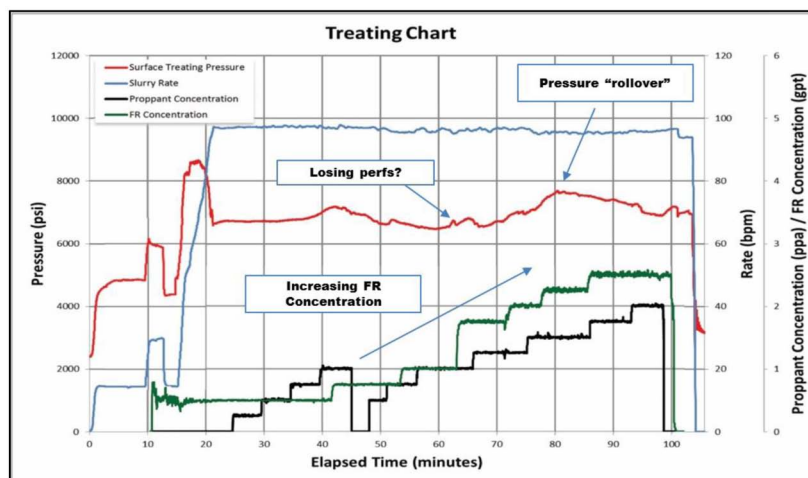


Figure 12—Treating chart from Delaware Basin frac using VFR fluid

Summary and Conclusions

The use of polyacrylamides in the oil and gas industry has evolved and expanded from applications in which higher levels of stability are required (drilling operations, acid gelling agents, EOR applications) to fracturing applications in which different properties are desired (friction reduction, viscosity development, clean breaks and high retained conductivity). To achieve these desired properties, new forms of polyacrylamides have been developed with fit for purpose chemical structures, including the use of lower molecular weight systems and different monomer types.

Three case histories have been presented which help to highlight some of the advantages being observed using VFR fluids. The key advantages of VFR fluids described in this paper include:

- Cost savings and operational efficiencies gained using fewer chemicals, less fracturing equipment on location, and simple QA/QC
- Reduced water requirements over slickwater treatments
- Enhanced viscosity development at low FR concentrations
- Improved fracture conductivities by placing higher proppant concentrations than slickwater type treatments and better retained conductivity than traditional guar-based linear and crosslinked gels
- On-the-fly design viscosity change capability to mitigate screenout risk at critical points during the treatment

VFR fluids can be used as direct replacements for linear and crosslinked gels in most cases. With the use of slickwater and hybrid-type frac designs still common in the industry today, the authors believe that significant opportunities exist for continued expansion of the use of VFR fluid systems.

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