Selection of friction reducer for slickwater fracturing to achieve both fracking robustness and production maximisation

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Abstract: Fracking robustness and production maximisation are the ultimate pursuits of slickwater fracturing. The former requires an 'all-weather' applicability of slickwater, whereas the latter dictates the fluid to be non-damaging to reservoir formation. Since friction reducer (FR) is the mere indispensable component of slickwater, the requirements for fluid essentially translate for this FR. In this report, an attempt is made to describe experimentally and comparatively the outcomes of FR screening based upon current industrial practices, which are often contradictory in nature, followed by the author's opinions and recommendations. Two commercially available FRs, with distinctive properties, were chosen for demonstration. Regarding fracking robustness, the assessments include a series of compatibility and friction flow loop examinations. The aspects of production maximisation are elucidated through core flood regained perm, proppants pack elution and filtration through porous media experiments. A simplified FR selection guide is proposed with its validity corroborated by field results.

Keywords: slickwater; hydraulic fracturing; friction reducer; fracking robustness; production maximisation; brine tolerance; formation damage.

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Biographical notes: J. Jim Wu is the President and CTO of Phoenix C&W, Inc. He received his PhD from the University of Toronto in 2004 and held various technical and managerial positions in multinational companies. His accomplishment is manifested by over 20 peer-reviewed journal publications in prestigious journals such as *Journal of the American Chemical Society* and *Macromolecules*, as well as 20 granted patents.

1 Introduction

Stimulations in the form of hydraulic fracturing or fracking to enhance oil and gas productivity are being conducted on both unconventional and conventional wells. As of the year 2012, more than two million 'frack jobs' had been performed worldwide, among which over one million were within the USA (King, 2012). Since 2014, hydraulically fractured horizontal wells accounted for most new oil and gas wells in the US. As of

2016, about 670,000 of the 977,000 producing wells in the country were hydraulically fractured and horizontally drilled (Cook et al., 2018). No recent worldwide statistics appears to be readily retrievable. By injecting fluid containing mainly water, along with proppants and chemicals such as friction reducer (FR) and guar or xanthan gums, fracking treatments are performed above the breaking pressure of the formation, creating highly conductive channels or fractures between reservoir and wellbore, allowing a better flow of oil, gas and water. Among fracking fluids being used, slickwater is getting more popular because of its intrinsic higher pumpability and presumably lower formation damage than conventionally adopted gel systems (Barati and Liang, 2014). Slickwater is a fluid composed of FR as the indispensable component, along with other additives such as flow back surfactant and clay stabiliser as optional.

One may delineate the play of slickwater fracking by two episodes: the actual fracking operation and the subsequent display of production enhancement. During the first segment, slickwater, along with proppants, are pumped downhole to the formation in order to enhance reservoir conductivity, which is normally carried out by so-called service or pressure pumping providers, with fracking robustness receiving the primary attention. The performance preservation of the chosen FR, in terms of pressure taming, in the presence of additives such as flow back surfactant and anticipated metal ions, are among the focal points. A series of tests, primarily consist of friction flow loop experiments, are conducted. Once a well is fracked, it is handed over to operating companies (*aka* E&Ps), where the extent of production enhancement, the results of which are directly linked to formation damage, is closely monitored.

Although fracking companies and E&Ps are anticipated to work abreast, situations are often attended with insufficient or inaccurate understandings derived from differed and sometimes subjective angles. For example, it's only natural for pumping companies to focus more on fracking robustness as they are not liable for production, regardless of which being the centrepiece for E&Ps. On the other hand, E&Ps rely heavily on service providers to recommend, regardless of whether their core interest is fully addressed. One may argue that there won't be any disconnect if both parties work seamlessly together as a team. However, the reality is far from being ideal, due to the availability of limited options, lack of communication/knowledge and discrepancy of interests. Thus, outstanding issues and conflicting opinions persist with few accounts over the following:

1 What is the required rock-bottom spectrum of FR compatibility to accomplish both fracking robustness and production maximisation?

2 Whereas a high-viscosity fluid suspends proppants well statically, does it carry far enough dynamically into formation? How about subsequent formation damage arising from high viscosity fluid?

3 What is the contribution of friction resistances to pumping pressure, as a result of fluid penetrating into reservoir?

4 What are the impacts of foreign substances such as ferric ions generated during fracking and squeezed one way to the formation?

5 Will the presence of metal ions native to connate water dampen production, upon meeting with FR molecules?

Although these factors listed above may not substantially alter actual fracking operation, as most of them don't come into play until fluid exits from the tubulars to the formation, they are expected to render paramount effects over the outcome of a frack job, which is often lackluster as a result of the central issue of formation damage being frequently overlooked.

In this report, attempt is made to describe the outcomes of FR screening as it relates to both fracking robustness and production maximisation, by adopting two commercially available FRs, denoted as FR-B and FR-2. Varieties of comparative assessments are illustrated along with rationalised recommendations. A simplified FR selection guide is proposed with its validity corroborated by field results.

2 Experimental

Unless otherwise noted, all the chemicals used herein were reagent grade. Numerous commercial FRs, although with little description, were assessed. It should be noted that it is a common practice in the industry to minimise disclosure for IP protection. For illustration and comparison with simplicity, two distinctive FRs were chosen, with one being a common inverse emulsion (‘*water-in-oil*’) FR, namely, FR-B, along with a dispersion product that was labelled as FR-2, which leads to complete dissolution in water. A detailed report on FR-2 can be found from the published literature (Wu et al., 2017).

2.1 FR compatibility in fresh water and brine

FR-B and FR-2, respectively, were added dropwise to agitated tap water (130 mL or ca. 4.6 oz.) in a transparent glass bottle at room temperature, to render a suspension or solution of FR at 1.0 GPT (stands for ‘gallons per thousand gallons’) or 1,000 ppm. The agitation was continued for 3 min. to ensure homogeneous mixing. In the case of FR-B, the resultant suspension remained cloudy regardless of the duration of agitation. In contrast, FR-2 turned to a clear solution near instantaneously upon mixing with water. The mixtures were then inspected visually for compatibility. Five drops of ferric chloride ($FeCl_3$, 10%) were introduced to each FR mixture under agitation, to render $FeCl_3$ concentration of ca. 200 ppm. Each mixture was then kept under agitation for additional 3 min, before it was checked for compatibility. A good compatibility was characterised by visible background stripes when conducting a front view through the bottle containing FR suspension or solution in the presence or absence of $FeCl_3$.

Once the compatibilities of FR in $FeCl_3$ brine were examined, the mixtures were then allowed to settle at room temperature for 30 min., before they were filtered through filter paper with an average pore size of ca. 20 µm, to segregate the solids. The filtrate was collected underneath the filter paper, which was sitting on a funnel. The volume of the filtrate was then measured, with a graduated cylinder, to calculate *solids content v/v%* by equation (1):

$$solids\ content\ {}^{v}\!/_{v}\,\% = \frac{vol.(total\ mixture) - vol.(filtrate)}{vol.(total\ mixture)} \times 100 \tag{1}$$

where *vol.(*filtrate*)* was the volume of the filtrate, *vol.(total mixture)* was the total volume of the original FR/$FeCl_3$/water mixture before filtration. Since the volume (5 drops) of

$FeCl_3$ solution (10%) was infinitesimal, the *vol.(total mixture)* was essentially the volume of the original FR/water mixture before adding $FeCl_3$.

2.2 Percentage friction reduction measurements

The basic principle for percentage friction reduction (FR%) determination is via measuring the fluid pressure drop within a fixed distance of the interior of a flow loop in the presence or absence of an FR, which is injected to the loop on-the-fly to mimic field scenario. The regular testing specs are as the following: temperature = ambient, interior diameter (I.D.) = 0.394 in (10.0 mm), flow rate = 7.9 gal/min (30.0 L/min), and FR dosage = 1.0 GPT (1,000 ppm).

The FR% is then calculated through equation (2):

$$FR\% = \frac{\Delta P_0 - \Delta P}{\Delta P_0} \times 100 \quad (2)$$

where *FR*% is the percentage friction reduction, ΔP_0 is the differential pressure in the absence of an FR at a specific flow rate, and ΔP is the pressure drop at the same velocity after adding FR.

2.3 Fluid viscosity measurements

The viscosities were recorded from a Fann® 35 viscometer. Aliquots of fluid containing FR at various concentrations, were placed in a sample cup with RPM set to be 300 (511/s) at room temperature. The reading was taken when it was stabilised. The test was conducted sequentially with using the aliquot that had the lowest FR concentration to minimise the error arising from cross-contamination. The dial reading at 300 RPM was the viscosity of the sample under standard Fann® 35 settings.

2.4 Core damage or regained perm experiments

Synthetic quartz cores with a diameter of ca. 0.98 in (2.5 cm) and a length of ca. 3.15 in (8.0 cm) were utilised for core damage assessment. A typical core has a porosity of ca. 20% and a permeability ranging from 40 mD to 200 mD. The permeability before damage (K_1) and after damage (K_2) were measured by letting N_2 flow in the inlet of the core holder at a flow rate below the critical flow rate to assure the applicability of Darcy's Law. The details of this process can be accessed from previous publications (Wu et al., 2017; Wu, 2019).

2.5 Elution/filtration measurements

Two slickwater samples (250 mL each) were prepared with using FR-2 and FR-B, respectively, before being poured into two parallel glass columns containing previously packed (with using water for assistance) 200-mesh proppants (200 g). The fluids were then allowed to flow out of the column with flow rate measured as drops/min. The flow rates were used to estimate the time for elution completion.

Alternatively, FR mixtures in fresh water or brines were poured onto filters with average pore size of 20 μm. Again, the flow rates were estimated as drops/min, and the counting was discontinued once the flow was regarded as 'stopped', meaning no visible drops coming out of filter paper within 5 min.

3 Results and discussions

3.1 Concepts clarification

Before proceeding to common practices of FR screening in the oil and gas industry, it is necessary to clarify a few concepts as they relate to discussions in this report. These concepts encompass 'friction', 'drag', 'shear' and 'turbulence' regarding the physics of the subject friction reduction; and 'solution', 'suspension' pertaining FR compatibility. Although the names of 'drag reducer' and 'FR' are adopted with a tendency of designating FR for aqueous whereas drag reducer for oil flow, they are essentially interchangeable. In the meanwhile, they are not meant to function in laminar flow reducing 'drag' or 'friction', a force acting opposite to the motion of a fluid layer with respect to surrounding matrix ('drag' and 'friction', Wikipedia). In this sense, shear is similar to 'drag' or 'friction' in nature. However, the energy inefficiency during slickwater fracturing, is not due to 'drag', 'friction' or 'shear'. Rather, it is predominately arising from the resistance by turbulence, which is a result of irregular fluctuations or mixing, in either oily or aqueous environment ('How Drag Reducing Agents Work', 2017; Oilfield Glossary, 2018). In contrary to well-understood friction reduction scenario such as lubrication, turbulence taming by falsely called friction reducer or FR in this context, remains a myth of classical physics (Eames and Flor, 2011). Since turbulence and turbulence taming (*aka* 'friction reduction' per se in this report) comes to play only when fluid deviates from laminar (where 'friction', 'drag' or 'shear' dominates) to turbulent flow with a dimensionless parameter Reynolds number *i.e.* Re# increases above a certain threshold, 'turbulence depressant' may be a more accurate term. Nonetheless, the customary appellation friction reducer *aka* FR is continuedly adopted in this report to ascertain consistency and to avoid confusion.

The definition of compatibility should be clarified as well. When stating substances are compatible in a common solvent, the formation of a 'solution' is required. A 'solution' is defined as a homogenous liquid with solutes fully mixed with solvent at molecular level (Definition of Solution, IUPAC). Thus, the compatibility of an FR is frequently poorly judged. It is viewed as compatible with water, even when a 'suspension' is observed, as long as there is no obvious precipitation. A 'suspension' is defined as a liquid in which undissolved solid particles are dispersed.

3.2 FR selection – common practices

Typical FR selection includes a brief compatibility evaluation along with friction flow loop testing. Usually, one looks into the compatibility of a few FR candidates with water and optionally other additives such as surfactant, clay stabiliser and biocide. FR compatibility with brines is considered only when produced water is utilised as carrier fluid. As was stated, an FR is regarded as compatible with water, even when a 'suspension' is observed, as long as there is no obvious precipitation. Main efforts are spent on identifying an FR with high percentage friction reduction (abbreviated as 'FR%') to assure fracking feasibility, *i.e.* pumping all chosen chemicals downhole. Little attention was given to understanding how the presence of insoluble particles might alter fracking robustness and to what degree they might damage the reservoir. Moreover, the roles of foreign species generated during pumping and intrinsic mineral ions in connate water on fracking are scarcely accounted. Therefore, FR compatibility needs to be re-visited with more depth and scrutiny, as well as other controversial issues such as fluid viscosity and largely unexplored area of formation damage.

3.3 FR selection for fracking robustness & subsequent recommendations

In this section, attempt is made to discuss:

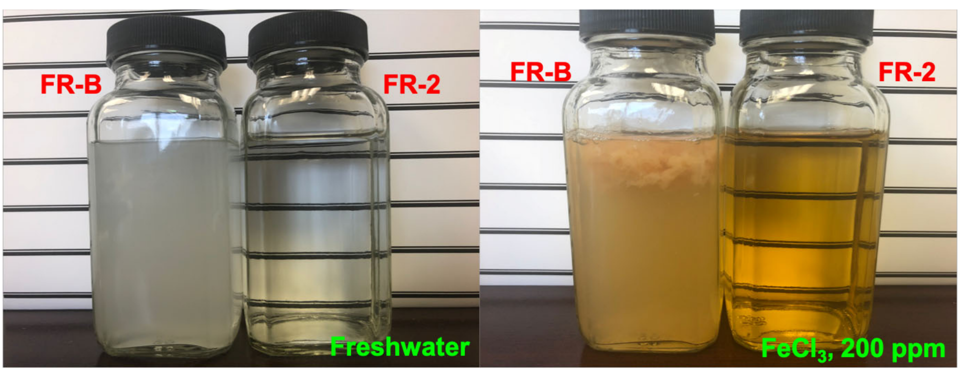
1 to what degree FR compatibility issues must be attended

2 metal ion for gauging adequate FR compatibility

3 comparative FR% by flow loop.

Other issues such as Re# vs. shear rate as it relates to laboratory artifacts, fluid viscosity as it relates to proppants carrying, and pumping pressure arising from fluid penetrating into reservoir, are also to be addressed.

Figure 1 Compatibility of FR-B & FR-2 with fresh water and $FeCl_3$ at 200 ppm (25°C; 1.0 GPT or 1,000 ppm), (a) freshwater (b) $FeCl_3$, 200 ppm (see online version for colours)



(a) (b)

Note: Good compatibility is characterised by visible background stripes through front view.

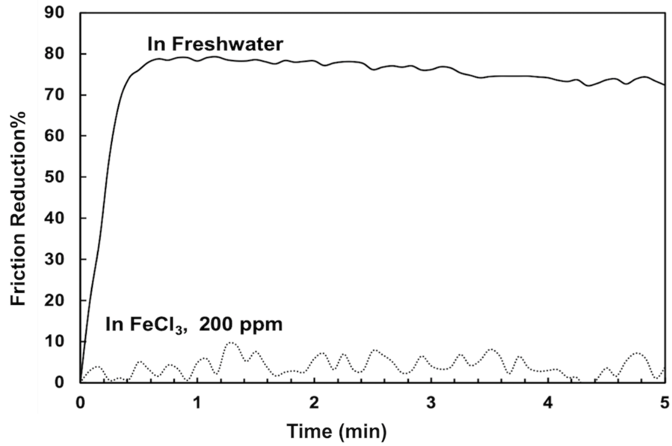
When designing fracking fluid, the first criterion should be whether the candidate FR renders transparent solution in water, rather than a suspension. As can be seen in Figure 1(a), FR-B, a common commercial FR, leads to a suspension, which remains cloudy even after sitting at room temperature for months. In contrast, FR-2 dissolves quickly into water under agitation [Figure 1(a)]. A clear, transparent solution was formed in less than 30 secs. suggesting a complete dissolution. As was stated above, an FR leading to a suspension rather than a solution should be automatically disqualified, as no one wants to take the risk of damaging their well, regardless of the FR% from subsequent flow loop experiment.

Next, we investigate how the target FR needs to be resistant against brines, as fracking robustness is directly linked to brine resistance. Three categories of FRs are available according to brine tolerance, namely, freshwater, low-brine and high-brine. As one may imagine, the cost of an FR increases with its brine compatibility. Thus, when one is utilising freshwater for fracking, he tends to pick a low-cost freshwater FR. However, one should perhaps take a pause before finalising his decision. Although freshwater is used at the wellhead, it eventually becomes salty once getting downhole and penetrating into the formation. The reasons are multiple folds. One is that hydrochloric acid (HCl) is almost always being applied during a frack job. HCl reacts with calcite to initialise rock breaking with the release of massive amount of calcium chloride ($CaCl_2$). Moreover, HCl reacts with carbon steel to produce iron ion. Thus, whenever HCl is applied in a frack job, the presences of calcium and iron ions are inevitable. These ions may hinder fracking operation with the extents subject to further investigation. Moreover, they are expected to be squeezed one way into the formation, where they function as muster points for FR molecules with poor iron resistance to aggregate. The resultant aggregates clog up precious flow channels, leading to maximised magnitude of formation damage and thus minimised production. After all, formation water is intrinsically salty with various abundances of metal ions such as ferric, calcium and magnesium. Therefore, brine tolerance of an FR has to be attended even when using freshwater.

One key question to ask is what brine should be used to gauge the FR compatibility. We recommend ferric chloride ($FeCl_3$) at a concentration between 100 and 300 ppm, as it was proven to be the most troublesome metal ion to FR. The presence of iron ion, in the form of ferric, leads to the formation of notorious ‘gummy bears’, the solution of which is expected to unlock greater shale production (Dulin et al., 2015; Wu et al., 2017; Hazra et al., 2020; Rassenfoss, 2020). Based upon massive experiments, it appears that once an FR is compatible with ferric, it works with all other common oilfield brines, but not the other way around. One may argue that they don’t need worry about iron as there is no iron in their produced water. However, the absence of iron in produced water does not mean that there is no iron in their reservoir. In fact, it would be the opposite. As was described above, iron-induced solids, either in the tubulars or in the reservoir, undergo one-way traffic after being squeezed into the formation. Thus, these iron ions, entrapped in rubbery mini-plugs or globs basically never flow back to surface and therefore won’t be detected in produced water. Thus, one still has to look into iron resistance of FR even when no iron is detected in their produced water. One caution is that although FR% is frequently presented as a result in the presence of high TDS brine (TDS: total dissolved solids), the subject brine often contains primarily monovalent metal ion such as sodium and potassium with the absence of the most troublesome iron ion in the form of ferric [Fe(III)]. This kind of high-TDS brine poses very little stress over the performance of an FR and therefore the thus-chosen FR won’t render broad enough fracking robustness.

As can be seen from Figure 1(b), by introducing $FeCl_3$ (200 ppm) to FR mixtures, massive solids were induced in the case of FR-B, whereas FR-2 remains clear. Separation of these solids via filtration shows that the solids content from FR-B mixture was ca. 5.0 v/v%, although only 0.1 v/v% was initially added. This was a 50-folds increase in volume. For a typical 20-stage horizontal well with each stage using 6,000 bbl. (954 m^3) of water at a FR dosage 1.0 GPT (1,000 ppm), approximately 6,000 bbl. (954 m^3, or 954 metric tons or 2.1 million lbs. by assuming the solids density be 1.0 g/mL) of solids are to be generated in-situ downhole in the formation. These rubbery globs block up the flow channel, negatively impacting both the fracking robustness and production enhancement. Therefore, whenever an FR precipitates in the presence of $FeCl_3$, this FR should be immediately disqualified.

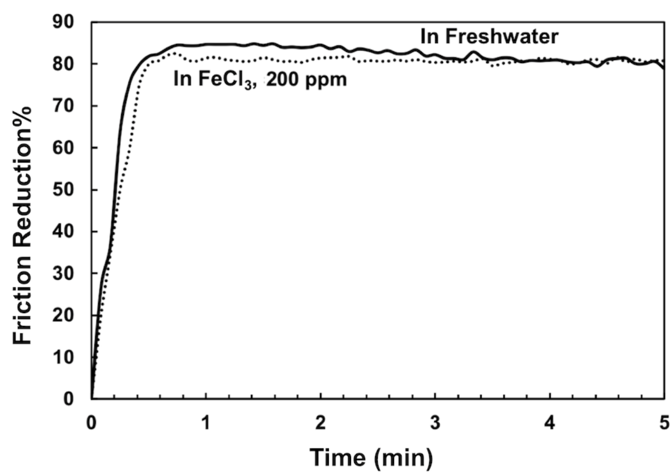
Figure 2 Friction reduction of FR-B (1.0 GPT or 1,000 ppm) in freshwater, and $FeCl_3$ (200 ppm)



Note: 25°C, solid line: in freshwater, dotted line: in $FeCl_3$

Besides FR's compatibility, one traditionally evaluates its extents of friction reduction in freshwater or produced water. Since ferric is an inevitable presence in reservoir and is the most troublesome ion, the tolerance with which ensures the greatest spectrum of fracking robustness, a recommendation is made for evaluating FR% in both freshwater and 200 ppm $FeCl_3$. As can be seen from Figure 2, at a dosage of 1.0 GPT (1,000 ppm), FR-B led to a friction reduction of ca. 80%, with the tailing friction reduction at 5 min above 75%. However, when merely 200 ppm $FeCl_3$ was introduced, massive solids were observed (Figure 1), and the FR% became essentially zero (Figure 2). It is recommended that once an FR failed iron compatibility test, it should be discontinued for FR% evaluation to avoid damaging friction flow loop. In contrast, FR-2 showed untamed FR% in the presence of ferric (Figure 3).

Figure 3 Friction reduction of FR-2 (1.0 GPT or 1,000 ppm) in freshwater, and $FeCl_3$ (200 ppm)



Note: 25°C, solid line: in freshwater, dotted line: in $FeCl_3$

3.4 FR selection – Re# vs. shear rate

It is well known that, in the lab, FR% is always dependent upon the specs of flow loop. Typically, Re# is a tiny fraction of that in the field and shear rate is folds greater. For example, according to equations (3) and (4), where Q is the volumetric flow rate, D is interior diameter and ν is kinematic viscosity (e.g., 1.0701mm^2/s), for a loop with an I.D. of 0.394 inch (10 mm), when flow rate is merely 2.6 gal/min (10 L/min), shear rate of 1698.5/s is already substantially higher than that (1,447.3/s) in a 4.65 in (118 mm) tubular at a pumping rate of 88 bbl./min (14 m^3/min). In contrast, Re# in the lab is only 19840.6 (0.84% of that in the field!), whereas that in the field is as high as 2,353,969. The reason for this discrepancy is that one cannot literally replicate field conditions in the lab. In order to increase Re# in the lab, one has to decrease the I.D. of the flow loop, as Re# is inversely proportional to this parameter. However, with the increase of Re#, shear rate is amplified even more, as shear rate is inversely proportional to the cube of I.D. In other words, if one reduces loop I.D. by ten folds, Re# ramps up by 10 times, whereas shear rate skyrockets by 1,000 multitudes. Moreover, shear, as a primary factor in laminar flow, is more dominant in small loop (e.g., 0.394 in or 10 mm I.D.) due to relatively thicker fluid/pipe interface, which becomes near negligible in a much larger pipe (e.g., 4.65 in or 108 mm I.D.). These substantial discrepancies compel artifacts in the lab. Therefore, scrutiny has to be in place in order to conduct meaningful experiments identifying a best FR for field applications.

$$Re\# = \frac{4Q}{\pi D v} \tag{3}$$

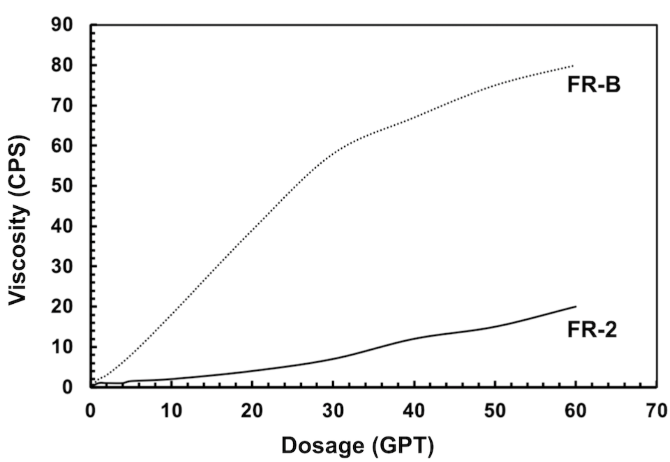
$$Shear\ Rate = \frac{32Q}{\pi D^3} \tag{4}$$

For a flow loop with fixed I.D., one may scan the FR% of an FR in freshwater by tuning flow rates. The max. FR% obtained with respect to flow rate, and regardless of the tailing FR%, is expected to sustain under field application, where the shear rate is merely a small portion of that in the lab. This is to avoid falsely disqualifying an FR with using excessively represented shear in the lab. For example, an inverse emulsion (‘w/o’) FR is known to have FR molecules protected by oil wrap under high shear environments. Therefore, it exhibits shear resistance substantially greater than what is required in the field. On the other hand, a ‘w/o’ FR forms cloudy suspension dominated by incompatible particles with unknown structures and complexities. These particles were shown to be extremely damaging to reservoir. In the meantime, a non-damaging clear FR may be wrongfully disqualified merely because of subjecting to a higher than necessary shear that is artificially created in the lab. Since all the commercial FRs are assessed extensively in freshwater before they are provided to end-users for evaluation, the step by using flow loop may be simply skipped for a quick initial assessment. The friction flow loop assessments may be resumed once one has completed essential preliminary screening and still has options.

3.5 FR selection – high-viscosity vs. low-viscosity

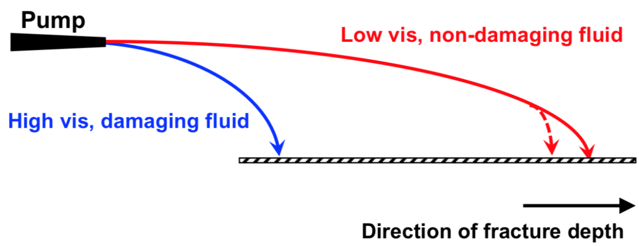
One other important issue frequently asked is what viscosity is optimal for fracking. Viscosity (vis for short) is such an important factor in that it is relevant to not only static proppant carrying, but also dynamic. More importantly, it is directly linked to formation damage, *i.e.* production enhancement. Currently, there are contradictory opinions and practices over FR selectin with regard to viscosity. As can be seen from Figure 4, FR-2 leads to significantly lower viscosity than FR-B at the same dosage. Although proppants barely settle before fluid front hits final destination, high-vis fluid does not travel far. On the other hand, A low-viscosity slickwater, although not as effective as high-viscosity counterpart in terms of static carrying, meaning proppants drops before fluid front hitting final destination, it propels farther dynamically (Figure 5). For an intuitive understanding of this scenario, one may choose sandstorm (also called dust storm or haboob) as an analogy. A sandstorm travels at 35–100 km/h (22–62 mph) (Haboob, Wikipedia), where air, with a dynamic viscosity of merely 0.01813 cps at 20ºC (Air-Dynamic and Kinematic Viscosity, The Engineering ToolBox), carries sands with a size up to 1 mm or 18 mesh with ease (Sandstorm, Weather Wiz Kids). During hydraulic fracturing, pumping speed can be as high as greater than 66 km/h or 41 mph (e.g., 75 barrels per min through 4-inch I.D. casing). Thus, this fluid (i.e., water herein) with a dynamic viscosity of 1.0 cps at 20ºC, which is ca. 55 folds that of air at the same temperature, would carry smaller sands such as 40/70 mesh (0.21–0.42 mm; vs. 1 mm by sandstorm) with no problems, at greater speed (41 vs. 22 mph), without additional viscosity enhancement. Thus, when one combines static and dynamic carrying, a low-viscosity fluid becomes an obvious choice. This is especially true when one takes the damaging nature of a fluid into account. One reminder is that the major drivers for switching from gels to slickwater were enhanced pumpability and foreseen low formation damage arising from low slickwater viscosity. Therefore, the practice of continuing going after high-viscosity fluid only appears to be against both original motives and proven benefits.

Figure 4 Viscosity profiles of FR-2 vs. FR-B at various concentrations (1 GPT = 1,000 ppm) in water (25°C)



Note: Solid line: FR-2, dotted line: FR-B

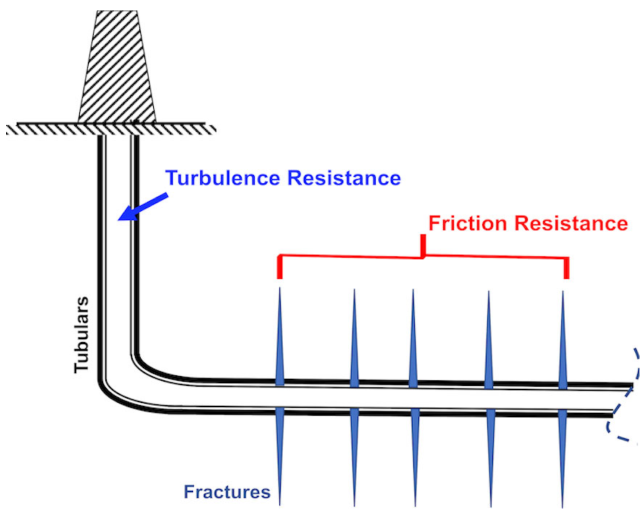
Figure 5 Illustrative sand-carrying by low-vis and high-vis fluid through trajectory shooting (see online version for colours)



Note: Low-vis/non-damaging, proppants travel far, but drop before hitting final destination; high-vis/damaging, proppants travel short but drop simultaneously with fluid

Fluid viscosity affects wellhead pumping pressure, too, when it penetrates into porous media of a reservoir. When a high-vis fluid is pumped, it compels greater friction resistance in fractures and thus increases pumping pressure. On the other hand, when a low-vis fluid is pumped, the elevated wellhead pressure is expected to be a minimum. It should be noted that the actual wellhead pressure is a function of both tamed turbulence resistance and reduced friction in the reservoir (Figure 6).

Figure 6 Illustrative scenario of fluid going through casing and penetrating into reservoir (see online version for colours)



Note: Casing: turbulence resistance dominant; fractures: friction resistance dominant

3.6 FR selection – formation damage

Although formation damage by slickwater should have been the focal point, it remains poorly investigated as of today. Studies have shown that after fracturing, the overall recovery of shale gas and oil was merely 5–7% (Jacobs, 2016). Reservoir damage by fracturing fluid remains a most probable factor to this industrial status quo, besides the intrinsic tightness of the reservoirs themselves.

Table 1 Core flood, regained perm by FR-B and FR-2

Friction reducer	*K_1 (mD)*	*K_2 (mD)*	*Regained perm%*
FR-B	166.3	0.5	0.3
FR-2	147.7	146.5	99.2

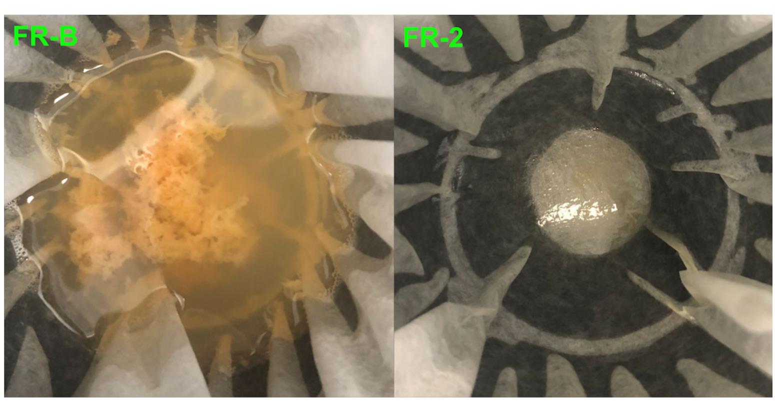
Table 1 summarises the regained perm by FR-B and FR-2. As can be seen, the regained perm for FR-B was 0.3%, whereas that for FR-2 was 99.2%. Core damage experiments may appear to be tedious and sometimes unrealistic to conduct under some occasions. Therefore, flow experiments through proppants pack or filter paper may be carried out as simplified alternatives. As was described in the experimental section, elution time through proppants pack was 68 min for FR-2 (1.0 GPT or 1,000 ppm), which is on par with that for freshwater. In contrast, it would take FR-B more than two years under the same conditions. Parallelly, when the same fluids were subject to filtration through filter paper with average pore size of ca. 20 µm, it took FR-B over 3 min, whereas FR-2 less than 30 sec, which is on par with that for freshwater (Table 2). Once 200 ppm $FeCl_3$ was introduced to each FR mixture, respectively, FR-B never came out of the filter paper, Massive solids left on the filter paper clogging up the pores and hence prohibiting continued flow (Figure 7). In contrast, it took FR-2 approximately 60 secs to finish eluting.

Table 2 Flow through filter paper (pore size of 20 µm) by FR-B & FR-2, over time

Sample	*3min*	*5min*	*10min*	*20 min*	*Leftover*
Water	over; < 30 s	--	--	--	No
FR-B	stream	0.8 drops/s	0.4 drops/s	0.0167 drops/s	trace
FR-2	over; < 30 s	--	--	--	No
FR-B ($FeCl_3$)	10 drops/s	0.6 drops/s	0.3 drops/s	0.033 drops/s	82 mL
FR-2 ($FeCl_3$)	over; ca. 60 s	--	--	--	No

Note: FR Dosage: 1.0 GPT (1,000 ppm); $FeCl_3$: 200 ppm

Figure 7 Images of leftovers on 20-micron filter paper after filtration (see online version for colours)

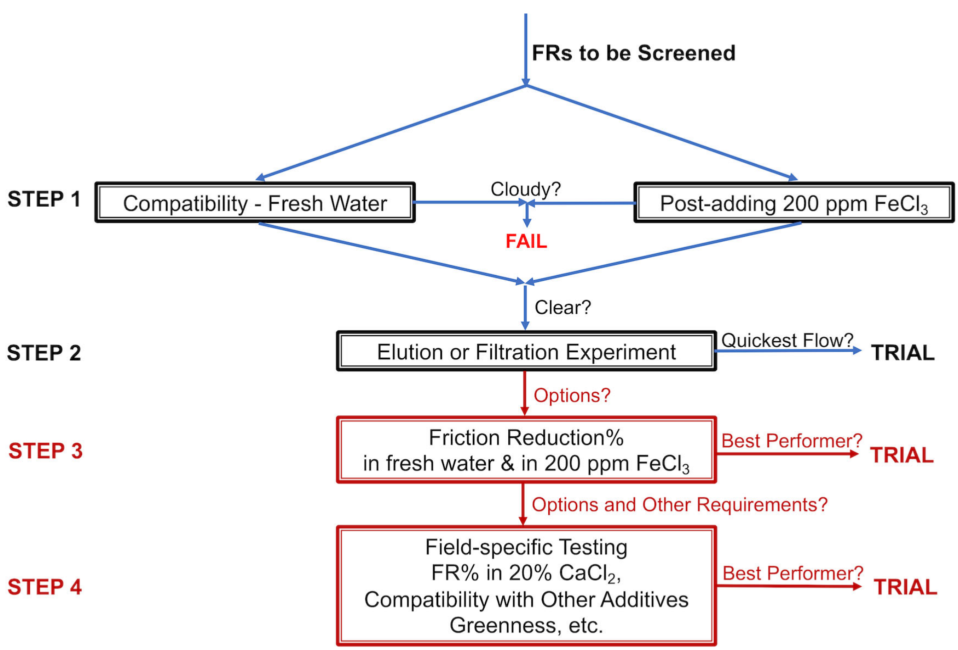


Note: Initial concentrations: FR-B & FR-2: 1.0 GPT (1,000 ppm), $FeCl_3$: 200 ppm

3.7 Simplified program for FR selection

One main goal of this report is to provide a simplified but meaningful guide for FR screening to ensure both fracking robustness and production maximisation. As compatibility dictates both of these two aspects, it is the first prerequisite. The use of freshwater and $FeCl_3$ at 200 ppm is recommended. By assuming all the commercial FRs are decent in FR% in freshwater, it is a 'pass' to all candidate FRs if they lead to a clear solution in both freshwater and iron (200 ppm). Subsequently, one ought to evaluate how quickly these FRs, in the presence of $FeCl_3$ at 200 ppm, flow through porous media such as a filter paper. FR% assessments with a flow loop and field-specific evaluations, such as reservoir temperature, compatibility with other additives including biocide or surfactant, environmentally friendliness, activation under low T and high TDS, should only be carried out if one is left with multiple options after compatibility and flow tests. One note is that although FRs are collectively classified as cationic, anionic and non-ionic, there are variations arising from entire formulations and manufacturing processes, which are normally kept secret by suppliers. For example, although a 'cationic' FR may be perceived as a better performer in high saline fluids, not all cationic FRs were made the same, with some found to be incompatible with clay and flow back surfactants. Viscosity was another highly debated factor. Whilst higher viscosity is favoured from static carrying perspective, e.g. to the level accomplished by gels (Dahlgren et al., 2018a, 2018b; Aften, 2018; Ba Geri et al., 2019a, 2019b; Jacobs, 2019; Guar Resources, 2020), it is not favoured from pumpability and formation damage aspects, as was illustrated previously. Again, all these belong to field or operator specific testing, to be addressed only after an FR has passed the STEP 1 & 2 of the simplified program and one still has options (Figure 8).

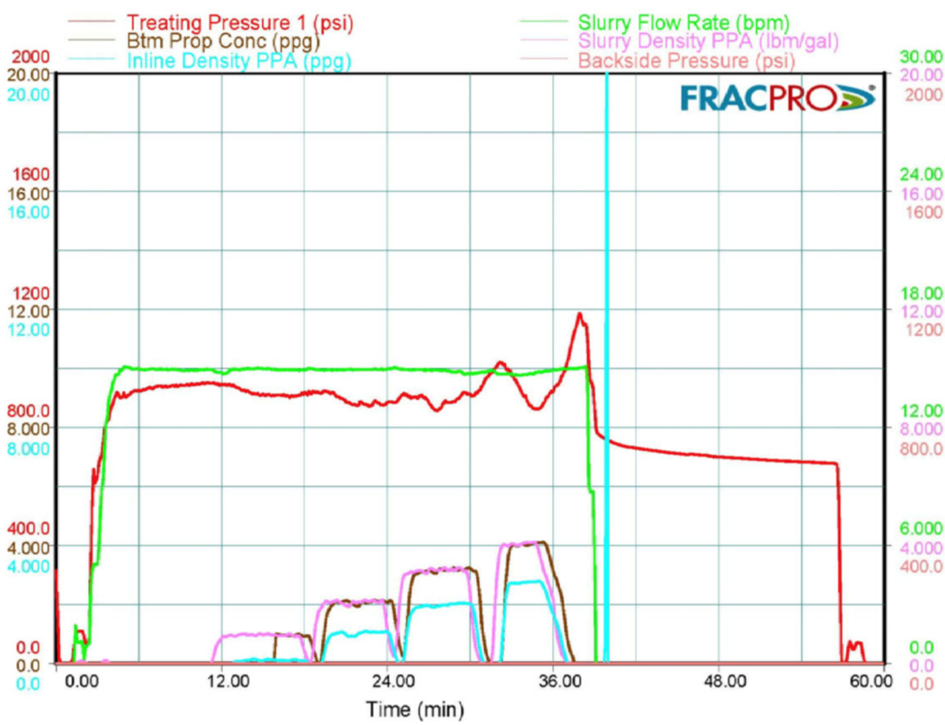
Figure 8 Flow chart for FR selection: black indicates required steps whereas brownish represents optional steps (see online version for colours)



3.8 *Field results corroborating simplified FR selection program*

As a truly compatible FR in both fresh water and $FeCl_3$ and a winner of quickest flow, FR-2 was reported previously being 10% more effective at taming pumping pressure, by conducting shoulder-to-shoulder comparison on a horizontal well (see Figure 10 of Wu et al., 2017). In one other case with using FR-2 only (viscosity: < 3 cps), 27,000 lbs. (ca. 12 metric tons) of brown sands (20/40 mesh, specific gravity SG: 2.65) was pumped downhole in Texas (sandstone/Olmos formation, Bear Creek field in Medina County) at a pumping rate of 15 barrels per minute (ca. 2.4 m^3 per min) in 18,696 gallons of fluid (ca. 445 bbl. or 71 m^3). The fluid was pumped through 4-1/2" (114.3 mm) casing with proppants rate increasing stepwise from 1 to 4 PPG (120–479 kg/m^3; PPG stands for pounds per gallon). The pumping pressure was quite constant with an average of ca. 950 psi or 6.55 MPa, which is about 50% lower than expected pressure. Moreover, the increase of proppants concentration led to no pressure jump (Figure 9). Most importantly, this subject well was shown to be 10 folds more productive than neighbouring wells fracked with regular slickwaters. In yet another field case, iron-resistant and quickest-flow FR-2 led to more than 6 folds oil enhancement than neighbouring wells after stimulation. The superb iron resistance and fluidity of FR-2 are undoubtedly playing the primary roles, leading to ease of reservoir penetration and flow path cleansing. The field results in terms of pressure taming and production enhancement, in turn, proved the validity of the simplified FR selection guide described previously.

Figure 9 Fracking profile by using FR-2 exclusively (see online version for colours)



Notes: Formation: sandstone; well depth: 2,488 ft. (ca. 758 m); casing: 4-1/2" (114.3 mm); red line: pumping pressure; pink line: proppants concentration.

4 Conclusions

An overview of practices regarding FR selection for slickwater fracturing is described. By walking through conflicting opinions and comparative experimentation to rationalised recommendation, requirements for enabling maximised fracking robustness and production enhancement are presented, followed by a simplified guide for FR selection with two most critical aspects to be attended, namely,

1 compatibility with fresh water and ferric

2 quickest flow going through porous media.

Although this guide is subject to further improvement and continued verification, field results appear to fully corroborate its validity.

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