Enter: SPE International Hydraulic Fracturing Technology Conference and Exhibition

Enter: SPE-215718-MS

Novel, Innovative Process To Improve Proppant Distribution And Improve Productivity In Hydraulically Fractured Unconventional Reservoir

Enter: Leopoldo Sierra[1], Larry Eoff[2], and Terry Palisch[3]

[1]StrataGen, Houston, Texas, USA
[2]Halliburton,Houston, Texas, USA
[3]CARBO Ceramics, Richardson, Texas, USA

Abstract

In fracturing treatments performed in unconventional reservoirs, propping agents are normally placed in the generated fractures using low viscosity fracturing fluids and friction reducers. It is generally accepted that a majority of the propping agents settle closer to the wellbore due to the poor transport characteristics of these thin fluids, limiting the propped area to the near wellbore region. This preferential settling can leave a majority of the generated fracture unpropped, and can result in:

- Reduced effective fracture-reservoir contact
- Low productivity and recovery of the stimulated well or reservoir
- Generation of long un-propped fractures
- Inefficient usage of the carrying fluids and chemicals

Extensive lab testing was performed to demonstrate the impact of variable viscosity on proppant transport and deposition. Fluids were built that covered a range of realistic slickwater viscosities and were then run through a slot with various proppant types and loadings, to observe the changes in deposition. This included the novel process of changing the viscosity within the same test run to simulate changes during an individual treatment.

The new process resulted in a substantially improved placement and distribution of typical conventional propping agents, including natural sand and ceramic proppant, and the effective placement of the proppants further away from the wellbore creating a longer propped and more conductive fracture.

While designed for unconventional reservoir stimulations, the novel process can also be utilized in fracture stimulations of tight or conventional reservoirs, and results in:

- Assured connectivity between the fracture and wellbore
- Maximized propped fracture length and height
- Maximized reservoir contact
- Engineered placement of the proppant in fracture or complexity as required
- Reduced use of water to create a similar or longer propped fracture length

Considering the improved proppant distribution in many simulated cases, this paper will review the development of the new process, present the results, and show the benefits to the user.

The new proposed process to improve proppant distribution will assure better productivity and higher hydrocarbon recovery factors in hydraulically fractured unconventional reservoirs. It will be beneficial for completions and reservoir engineers who wish to improve the drainage area and ultimate recovery in their assets.

Introduction

Hydraulic fracturing is a crucial stimulation process to assure productivity and maximize recovery or economics in unconventional hydrocarbon producing reservoirs, and an equally important process for the same purpose in tight-oil or -gas producing reservoirs. It is also required to improve productivity of wells containing completion damage, as well as for sand production control purposes and for asphaltene deposition control in conventional reservoirs. During the hydraulic fracturing process, proppant is injected to prevent fractures from closing and provide a high conductivity flow channel for oil and gas to flow (Economides and Nolte, 1989; Osiptsov, 2017). Recent research has shown that the proppant distribution is crucial for the well productivity (Cipolla et al., 2008).

Proppant transport and placement inside the hydraulic fractures are controlled by the fracture geometry, the rheology of the fracturing fluids, pumping schedule, and proppant particle shape, size and density. Proppant transport will impact both the propped fracture geometry as well as the conductivity of the fracture (Palisch, et al 2008). Extensive work has explored the complex interactive processes involved in proppant transport and placement, including Dontsov and Peirce (2015).

One common way to improve the proppant transport and placement inside the generated fracture is using conventional fracturing fluids such as high viscosity or crosslinked fluids, particularly in conventional reservoirs. However this alternative is not viable in unconventional reservoirs where due to the low (or ultra-low) permeability conditions, reduced fluid leak-off and long fracture closure time, a low viscosity fluid, more commonly slickwater, is used to transport the proppant from surface to downhole. Although the low viscosity of the carrying fluid permits the generation of fracture complexity in cases where the hydraulic fracture is placed in brittle formations, the proppant settling due to the typical Stoke’s law is significant, resulting in the proppant settling along the lower section of the generated fracture (**Figures 1 and 2**).

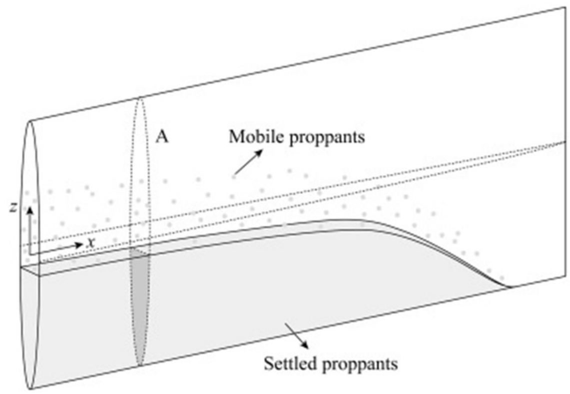

Figure1 – Proppant or natural sand settling along the lower section of the hydraulic fracture(Wang et al. 2018)

The proppant settling profile shown in Figs.1 and 2 could be associated to the completion cases where the wellbore landed away from the lower section of the stimulated horizon. However the settling profile and its effect over the well productivity as documented by Sierra et al. (2014) for the cases where the wellbore navigates is landed in the lower section of the stimulated horizon, will primarily generate a proppant dome dune located away from the wellbore. This could result in poor fracture conductivity or fracture closure near the wellbore.

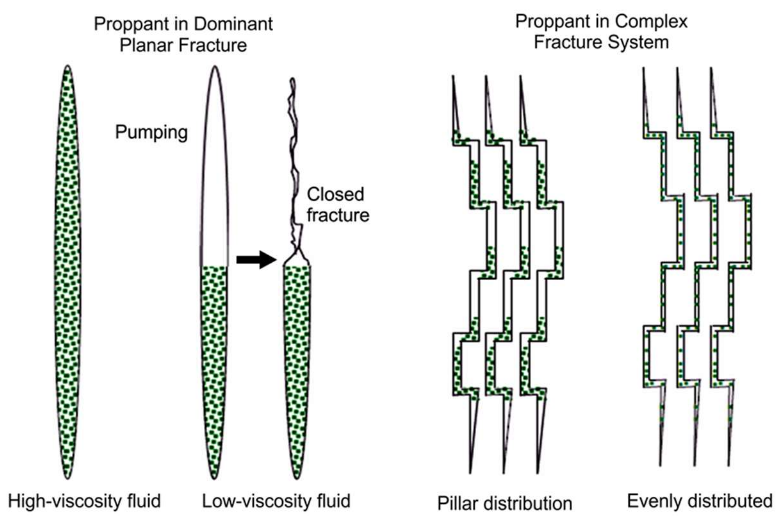

Figure 2 – Theoretical proppant distribution and settling schematics in Unconventional Reservoirs (Cipolla et at. 2008)

The propping agents bank distribution, length and height is highly affected by the settling effect especially when One Low Viscosity carrying (OLV) fluid system is used to stimulate unconventional reservoirs. For the cases where OLV slick water is used for proppant placement, the proppant settled bank will start growing progressively from the wellbore to the fracture tip as shown in Fig.1. This means that the first proppant pumped during the fracturing process will primarily be deposited near the wellbore. The first proppant bank preferential colocation around the wellbore will experience the highest closure stresses and highest fluid velocities generated during the production period and will therefore have a large impact on well productivity, hydrocarbon recovery and economics.

To minimize the negative effect of the localized proppant settling effect over the generated propped fracture geometry, conductivity, propped length, etc. numerous lab evaluations were performed and documented in US Patent No. 10,808,515 B1. Based on the results, the authors propose the use of a variable or engineered slick water fluid viscosity system to place different sizes or quality proppants close to, or further away from the wellbore, to build the proppant bank as required to:

- Engineer the proppant bank geometry
- Place better quality proppants as desired around the wellbore or any section of the propped bank
- Increase the effective fracture length
- Increase the proppant bank conductivity farther from the wellbore
- Assure the well productivity
- Increase hydrocarbon recovery factor (RF), etc.

New proppant distribution lab experiments: Design, evaluation criteria, and results

Experimental Set Up

Proppant distribution was tested utilizing a glass slot whereby a proppant slurry is pumped through the slot and then determining the amount of settling occurring in the slot. The set up is shown in **Figure 3**.

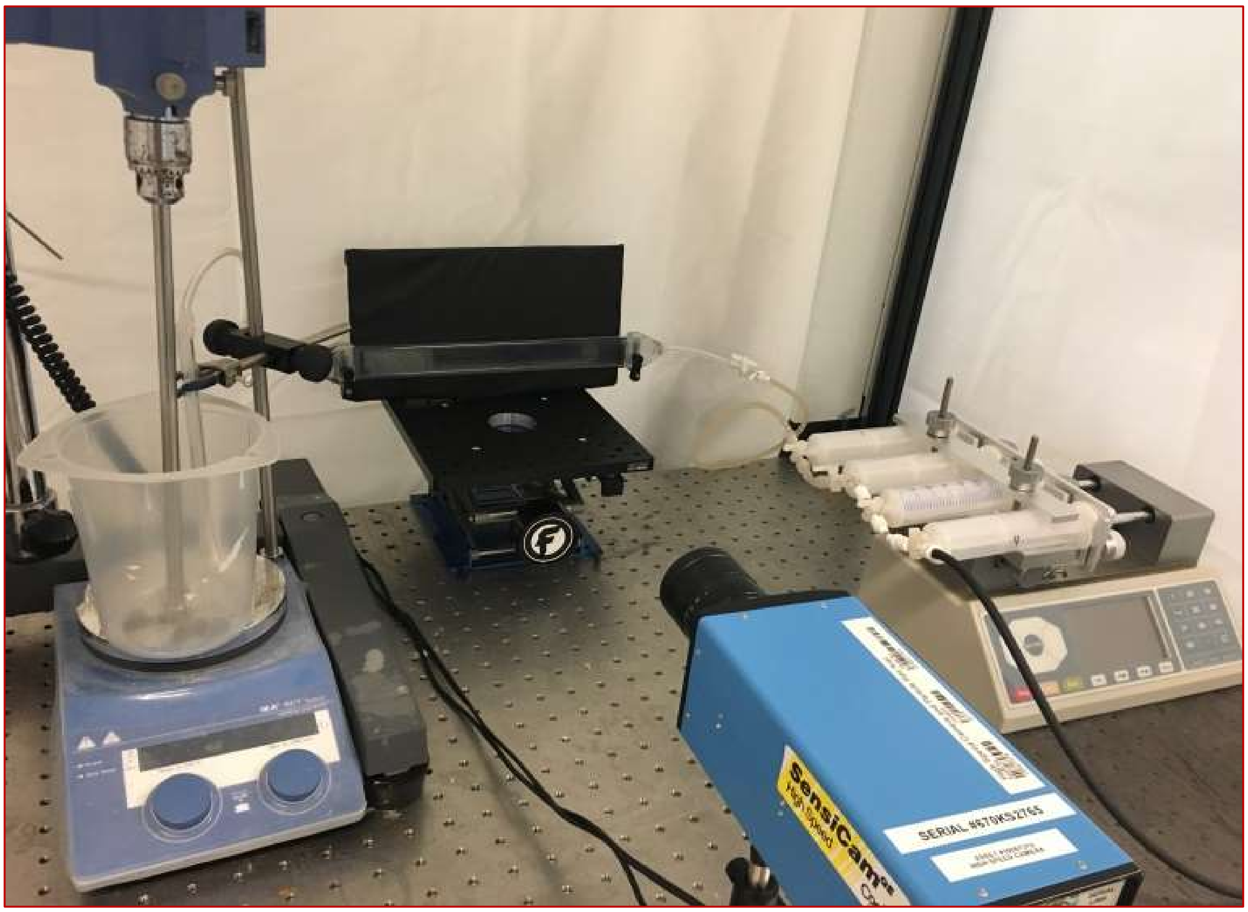

Figure 3—Slot Flow Set Up

The proppant slurry is placed in the beaker on the left side and stirred with an overhead stirrer to maintain proppant suspension. The slurry is pulled into the glass slot via vacuum supplied by the syringe pump shown on the right side. The process is captured with the camera in the middle and the resulting images are processed to determine the amount of proppant deposited in the slot. A value designated Proppant Distribution Index (PDI) was the result of this process, with normalized values ranging from 0 to 1, whereby 0 represents complete settling of the sand and 1 represents no settling (all proppant carried through the slot to the syringes). **Figure 4** illustrates the amount of settling for various PDI values. As shown, for a PDI of 0.1 significant settling has occurred at the left side of the slot, which is where the proppant slurry enters. As the PDI increases less proppant settles next to the entry point, resulting in less proppant settled in the slot and more carried out to the syringe pump.

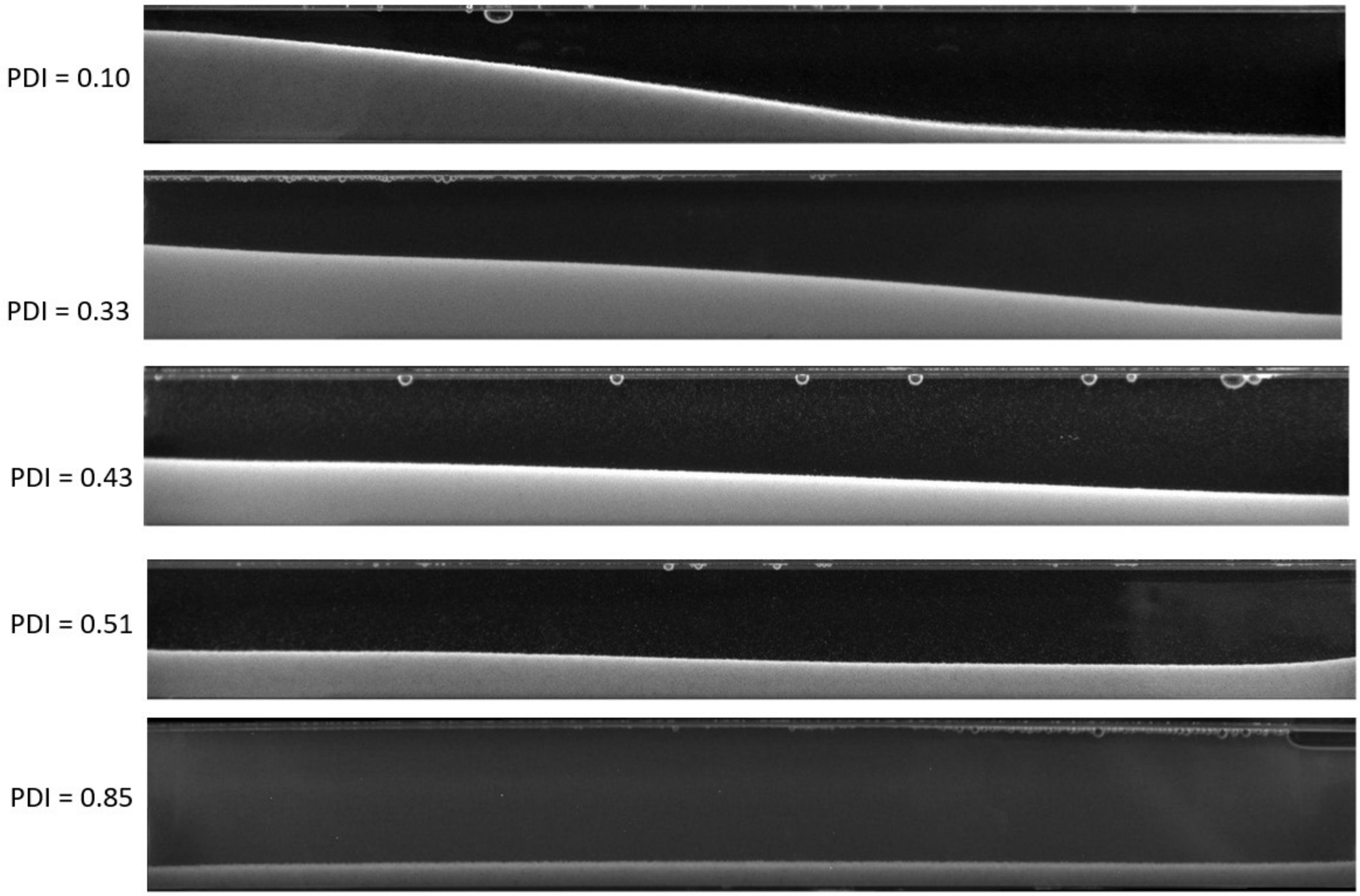

Figure 4— Example PDI settling levels

Experimental Results

Various friction reducers were tested in the slot flow apparatus, comparing loading, viscosity, and type of friction reducer. **Figure 5** shows a plot of PDI vs viscosity for one friction reducer (FR1), where the change in viscosity is due to variations in concentration of FR1. **Figure 6** shows the slot at the end of the test with 0.5 gal/Mgal FR1, which had a viscosity of 6.4 cp. **Figure 7** shows the slot at the end of the test with 1.5 gal/Mgal FR1, which had a viscosity of 26.7 cp. Numerous tests were run with different FR's, all confirming similar behavior – fluid viscosity can be used to control proppant placement.

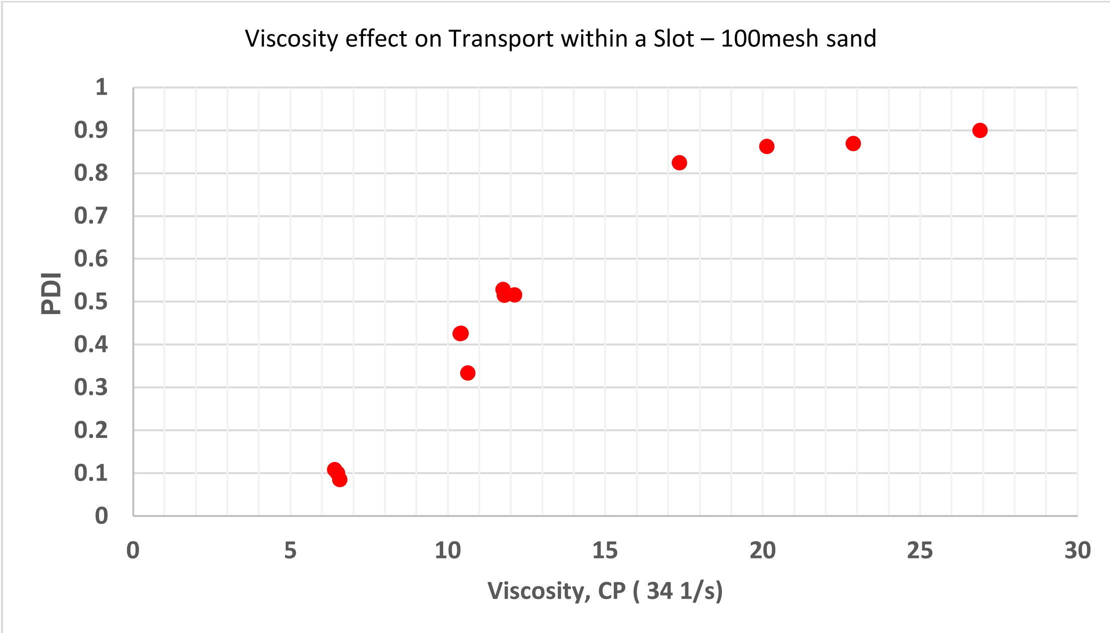

Figure 5— PDI values for FR1 at different concentrations/viscosities

Figure 6— Slot results for 0.5 gal/Mgal FR1, 6.4 cp

Figure 7— Slot results for 1.5 gal/Mgal FR1, 26.9 cp

Innovative proppant distribution benefits for maximizing productivity in unconventional reservoirs (UCRs)

As documented previously (Sierra 2014), stimulated well performance after placing single type (One type) proppant in the generated fractures using a single low viscosity (one low viscosity) fluid will be highly dependent on many factors, including the proppant distribution along the generated fracture, the effective propped height, effective propped length, propped fracture conductivity, reservoir permeability, the fracture conductivity of the non-propped section of the generated fracture once the proppant settles and the wellbore landing level along the prospective completed formation.

In addition to the previously listed negative effects as is shown in Figure 8 when the conductivity for the non-propped section of the generated fracture is zero; the excessive settling can drastically affect the stimulated well productivity and the recovery factor if the fracture spacing is not corrected to reduce this effect. For example as shown in Figure 8 to maximize the gas recovery in a well where the wellbore is landed in the upper portion of the prospective formation, the fracture spacing needs to be reduced to 70% if the propped height or the effective fracture height ratio is 0.4 or 40%. The effective fracture ratio as described in previous paper is the ratio of the propped height-to-pay thickness.

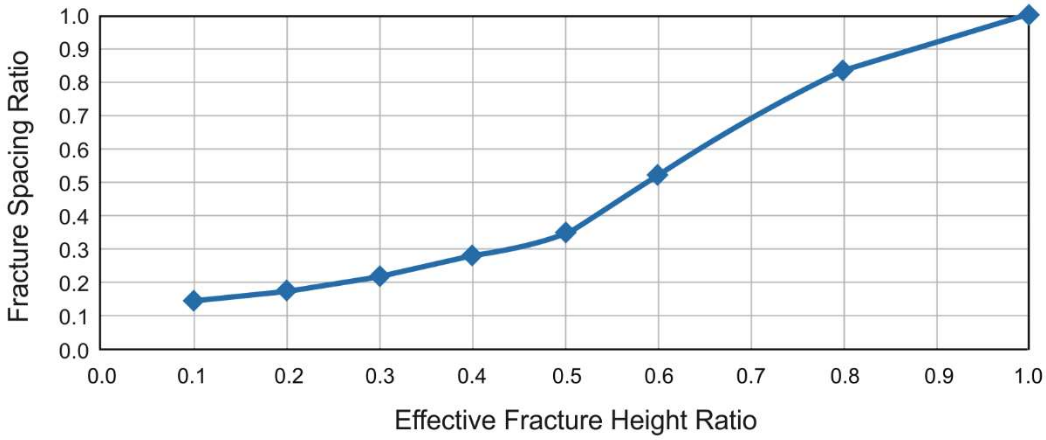

Fig. 8—Optimum fracture spacing ratio vs. effective fracture height ratio.

As was mentioned before the negative effect of the proppant settling will also depend on the reservoir permeability and wellbore landing interval as shown in Table 1 for three ranges of reservoir permeability and landing zones.

COMPARATIVE RF AND PRODUCTIVITY DROP FOR 10-nd PERMEABILITY RESERVOIR									
10-nd Permeability Case: 10-Year RF					10-nd Permeability Case: Productivity Drop				
Completion Point	Uniform Proppant Distribution	20% Settling	40% Settling	80% Settling	Completion Point	Uniform Proppant Distribution	20% Settling (%)	40% Settling (%)	80% Settling (%)
Top layer	21.34	18.94	17.57	16.82	Top layer	—	-11.2	-17.7	-21.2
Middle layer	21.36	21.37	21.37	18.19	Middle layer	—	0.0	0.0	-14.8
Bottom layer	21.41	21.43	21.36	21.04	Bottom layer	—	0.1	-0.2	-1.7

COMPARATIVE RF AND PRODUCTIVITY DROP FOR 100-nd PERMEABILITY RESERVOIR									
100-nd Permeability Case: 10-Year RF					100-nd Permeability Case: Productivity Drop				
Completion Point	Uniform Proppant Distribution	20% Settling	40% Settling	80% Settling	Completion Point	Uniform Proppant Distribution	20% Settling (%)	40% Settling (%)	80% Settling (%)
Top layer	67.32	47.93	41.15	36.12	Top layer	—	-28.8	-38.9	-46.3
Middle layer	67.36	67.4	66.9	43.87	Middle layer	—	0.1	-0.7	-34.9
Bottom layer	67.34	67.64	66.9	63.19	Bottom layer	—	0.4	-0.7	-6.2

COMPARATIVE RF AND PRODUCTIVITY DROP FOR 1,000-nd PERMEABILITY RESERVOIR									
1000-nd Permeability Case: 10-Year RF					1,000-nd Permeability Case: Productivity Drop				
Completion Point	Uniform Proppant Distribution	20% Settling	40% Settling	80% Settling	Completion Point	Uniform Proppant Distribution	20% Settling (%)	40% Settling (%)	80% Settling (%)
Top layer	67.52	30.73	23.93	26.06	Top layer	—	-54.5	-64.6	-61.4
Middle layer	67.52	67.53	66.19	28.55	Middle layer	—	0.0	-2.0	-57.7
Bottom layer	67.58	67.42	66.31	58.15	Bottom layer	—	-0.2	-1.9	-14.0

Table 1 – Comparative RF and Productivity drop for diferentes different reservoir Permeability and Landing levels (Sierra 2014)

For the RF's comparison shown in Table 1 a propped fracture model was set up considering a rectangular type of tapered proppant pack as shown in Figure 9, considering the propped fracture width changed from 0.1 to 0 inches and conductivity decreased from 108 to 0 md-ft, with both changes every 12.5 ft and using the same proppant. In addition to the width and conductivity, the effective stress over the proppant bed conductivity due to the depletion effect was considered.

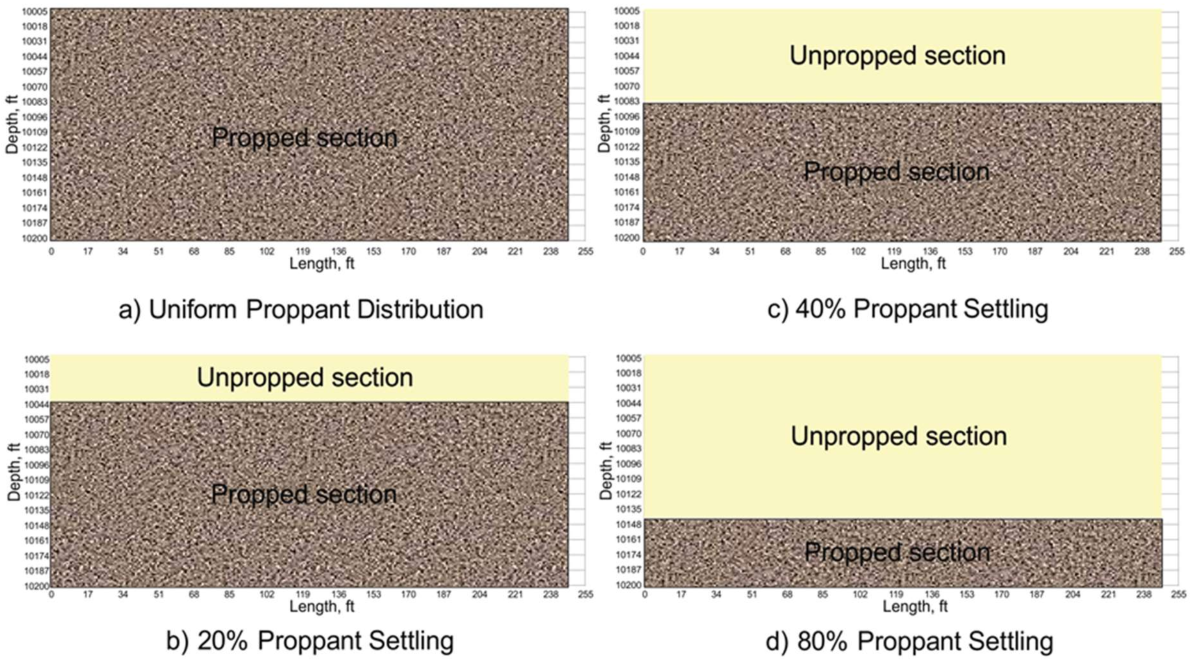

Figure 9—Optimum fracture spacing ratio vs. effective fracture height ratio model setup.

Although all the previous assumptions were enough to probe the negative effect of the non-engineered proppant distribution over the productivity and/or RF's in unconventional reservoirs, the rectangular shape of the propped fracture and the use of a single type of proppant is still not a close representation of the propped fracture geometry observed at the lab level, where primarily a long-base triangular type of proppant bed is observed. For the new innovative proppant distribution discussed in this paper, the process considers the use of different viscosities of carrying fluids and different types of proppant to engineer the propped fracture geometry and conductivity as shown in **Figure 9**.

Simulated benefits of the innovative process

Based in the lab test observations documented in the US Patent No. 10,808,515 B1 the following consideration have been made for the reservoir properties, fluid systems and propped bed geometry to demonstrate the inherent benefits of the novel method to improve the proppant distribution inside the induced fractures.

- **Reservoir.** Reservoir size, layering and reservoir permeability as shown in Table 2 have been utilized to setup the reservoir model for performing the comparative production forecasting.

Reservoir		
Formation top (ft)		8000
Formation Bottom (ft)		8200
Horizontal Permeability (nD)		300
Vertical Permeability (nD)		30
Layers from 8000-8080 ft		4 x 20 ft
Layers from 8080-8088 ft		1 x 8 ft
Layers from 8088-8100 ft		6 x 2 ft
Layers from 8088-8100 ft		20 x 5 ft
Horizontal well navigation depth		8100 ft
Reservoir size for simulations	Width (ft)	100
	Length (ft)	1000
	Thickness (ft)	200

Table 2 – Reservoir properties considered for the comparative simulations

- **Fluid systems:** Gas and oil fluid system have been considered for the comparative production performance evaluation. For both fluid systems the general fluid properties at the reference pressure, as well as the relative permeability is shown in **Figures 10 and 11**.

Fluid Type	Gas
Gas sg	0.65
Reference Pressure (psi)	4928
Initial Viscosity (cPo)	0.023
Temperature (oF)	250

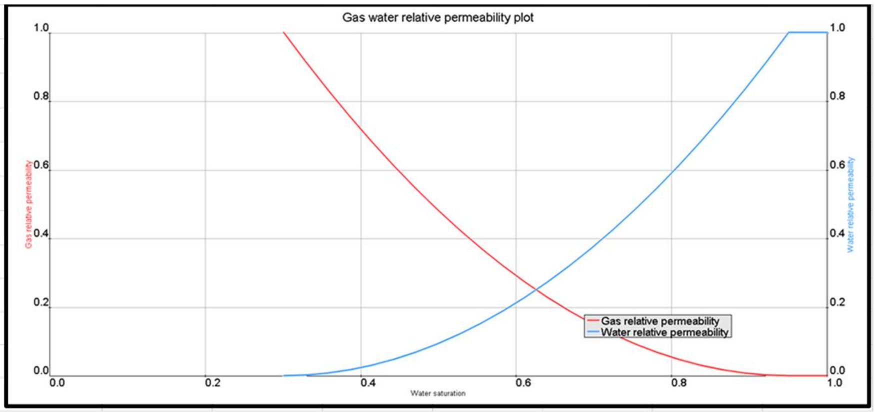

Figure 10—Model relative permeability curves gas & water.

Fluid Type	Oil
API	45
Reference Pressure (psi)	4958
Initial Viscosity (cPo)	0.22
Gas in Solution (Rs, scf/Bbl)	1170
Volume Factor (Bo)	1.7
Temperature (oF)	250

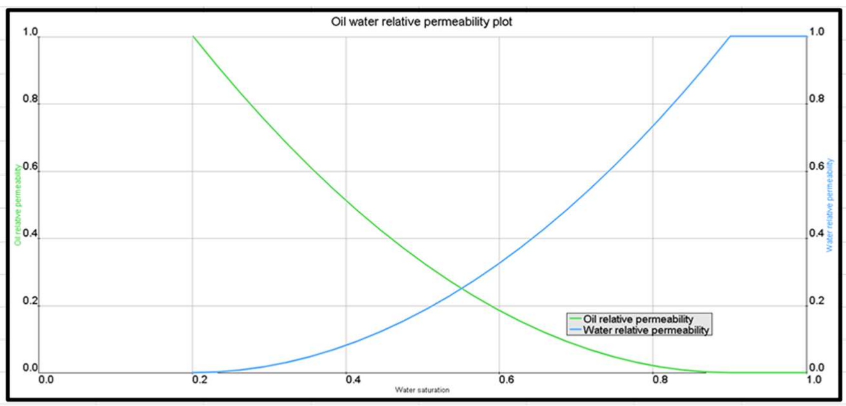

Figure 11—Model relative permeability curves for oil & water.

- **Fracture geometry and proppant distribution scenarios considered for the simulations.** Three specific propped fracture geometries with tapered fracture width from wellbore (0.3 in) to fracture tip (0.002 in) were considered for the comparative production performance for both gas and oil production reservoirs for which properties are described in a previous section. Two types of proppants were evaluated as the main proppant for the generated fracture - 30/60 mesh intermediate density ceramic (IDC) as well as a 40/70 mesh white sand.

  The initial conductivity of each section of the fracture and cases have been calculated based on the reported API conductivity of the proppant at stresses ranging from 0 to 12000 psi. This considers the variable effective stress effect over the fracture conductivity during the production period. Additionally, conductivity impacts due to the reservoir temperature, variation of the fracture width, typical fracturing fluid damage and turbulence (non-Darcy) effect have also been considered for all the simulations.

  Figure 12 shows the details of the final propped fracture profile generated using the novel innovative process to improve proppant distribution presented in the paper. The blue colored section represents four fractures where the proppant bed is generated using a low viscosity (2 cPo) carrying fluid having a high settling effect. The high settling effect results in the preferential location of the proppant near the wellbore for the first step and its subsequent location above the proppant bed placed in the lower section of the fracture using a higher viscosity fluid as observed in the corresponding figure. The low viscosity fluid system as described in the lab testing section is generated adding a commercial friction reducer to the water.

The other colored sections correspond to additional propped fracture geometry generated where the same type of proppant is deposited on top of each previous propped fracture, by being transported further into the fracture when a higher viscosity (10 cPo) carrying fluid system is used. The lab tests show the higher fluid viscosity is responsible for the farther travel of the proppant and it's the preferential location tendency of the lower section of the created fracture. Again, the higher viscosity fluid system is generated by adding another commercial friction reducer to the water.

As documented in the lab testing section, the alternate use of two fluid viscosities to carry the proppant into the fracture will promote the more effective vertical and lateral coverage of the created fracture. The improved vertical and lateral coverage of the generated fracture as shown in the simulations will promote the more effective drainage of the hydrocarbons, especially in UR's.

The comparative production simulations consider seven fractures profiles for each simulated case where the geometry, position, type of proppant and connectivity with the wellbore effects are also considered.

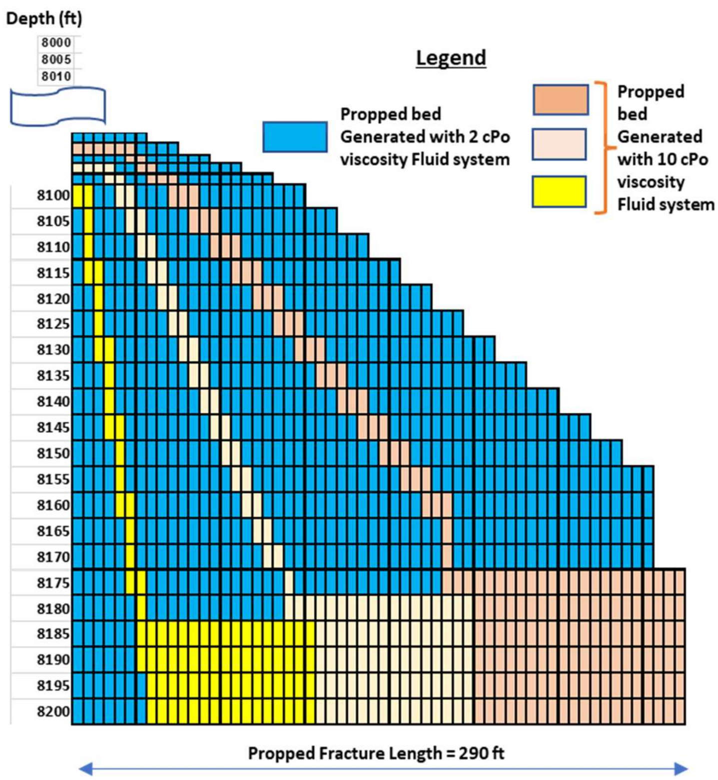

Figure 12 — This figure shows the impact on propped fracture length and height with each subsequent stage deploying higher viscosity frac fluid.

For the first case (Case 1) as shown in **Figure 13**, the previously described innovative process was used to place 30/60 IDC in the fracture but using two different viscosity carrying fluid systems alternatively as described before. For this specific case, the horizontal wellbore is placed in the middle of the 200 ft of prospective low permeability formation. The propped bed of 290 ft half-length is placed below the landing depth of the wellbore located at 8100 ft.

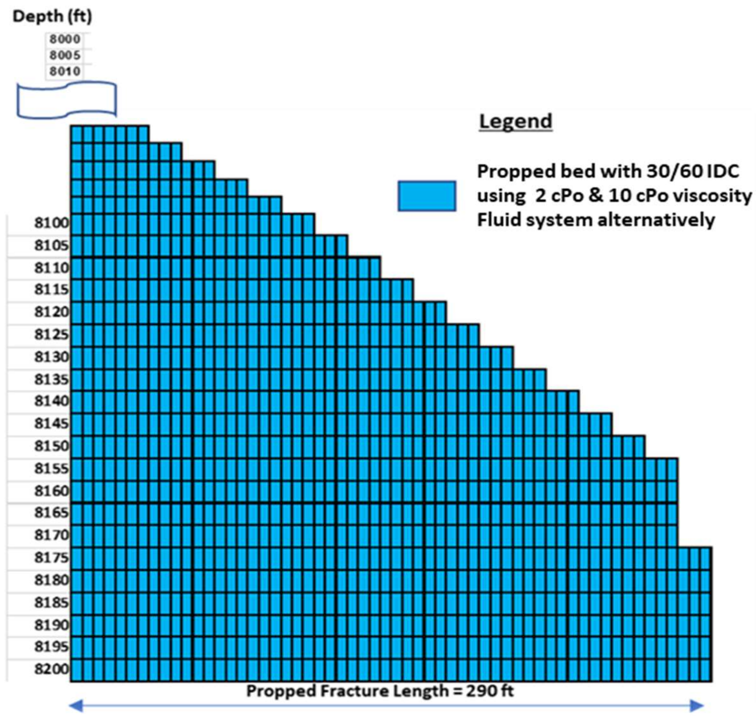

Figure 13 — Propped fracture geometry using 30/60 mesh IDC proppant and the innovative packing process

For the second case (Case 2) as shown in **Figure 14**, the previously described innovative process was used to place 40/70 mesh white sand in the fracture, again alternating two different viscosity carrying fluid systems. For this additional case, the horizontal wellbore is also placed in the middle of the 200 ft of prospective low permeability formation. The propped bed of 290 ft half-length is placed below the landing depth of the wellbore located at 8100 ft.

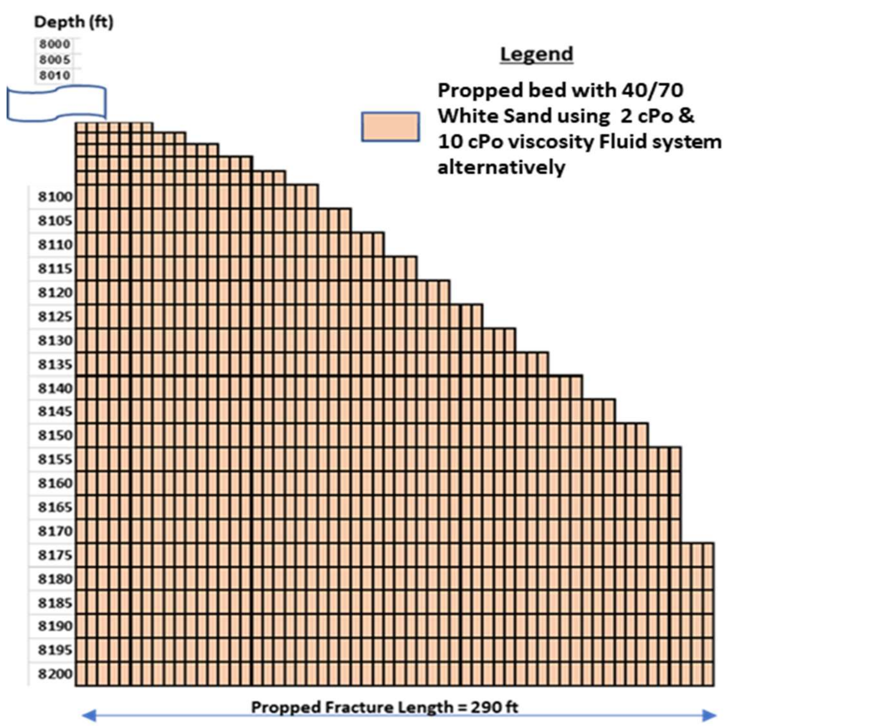

Figure 14 — Propped fracture geometry using 40/70 mesh Jordan Sand and the novel innovative packing process.

For the third case (Case 3) as shown in **Figure 15**, a conventional single viscosity carrying fluid system and 40/70 white sand having a propped fracture geometry with a limited connectivity near the wellbore area is considered to simulate the hydrocarbon productivity. For this additional case, the horizontal wellbore is placed also in the middle of the 200 ft of prospective low permeability formation. The propped half-length of 470 ft is located mainly in the lower section of the fracture.

To be able to perform a fair comparison between the 3 cases, a longer propped fracture length (470 ft) is used to set up the fracture model for the last case. The propped length for the third case has been estimated considering similar fracture volumes associated to the first and second cases. Using this volumetric correction, the reservoir volume used for all the simulated cases was: 1000 ft (Total length) x 200 ft (Thickness) x 100 ft Total width).

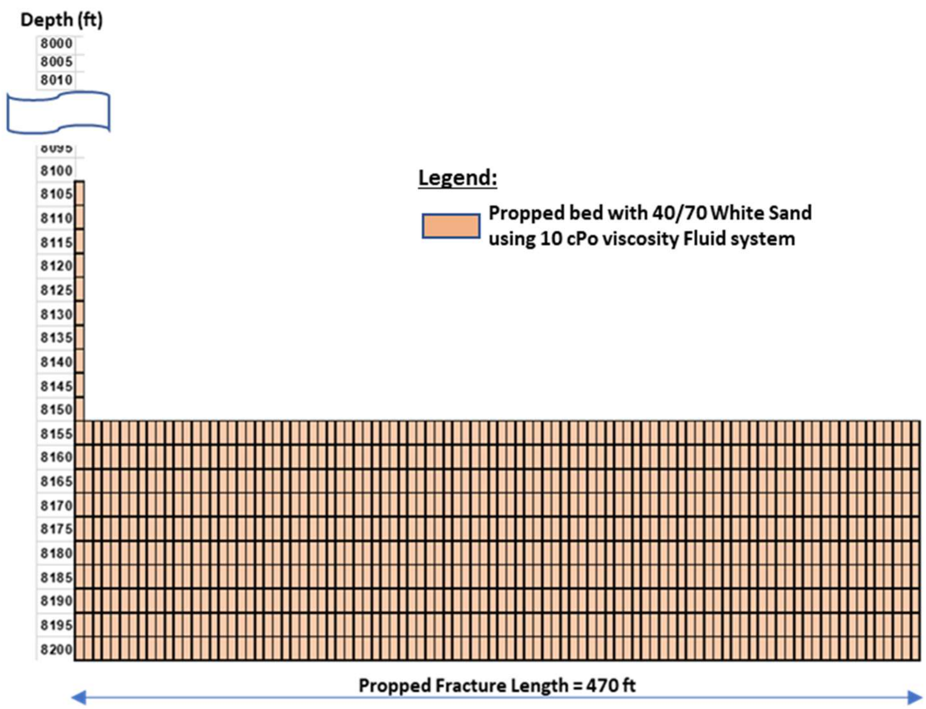

Figure 15 — Propped fracture geometry using 40/70 mesh Jordan Sand and a standard single viscosity fluid.

- **Comparative production simulations for innovative proppant distribution and conventional methods**

  The comparative production simulations resulting from the use of the proposed proppant distribution and the conventional methods have been performed for typical gas and oil producing reservoirs. The detailed reservoir, fluids and relative permeabilities is presented in previous section of the paper. For both fluid systems the same fracture geometry, tapered fracture width and conductivities have been used.

  The comparative cumulative gas production for the 3 cases as presented in **Figure 16** shows increased well productivity and RF's when the novel proppant distribution method (Case 1 & Case 2) is used instead of the conventional method (Case-3).

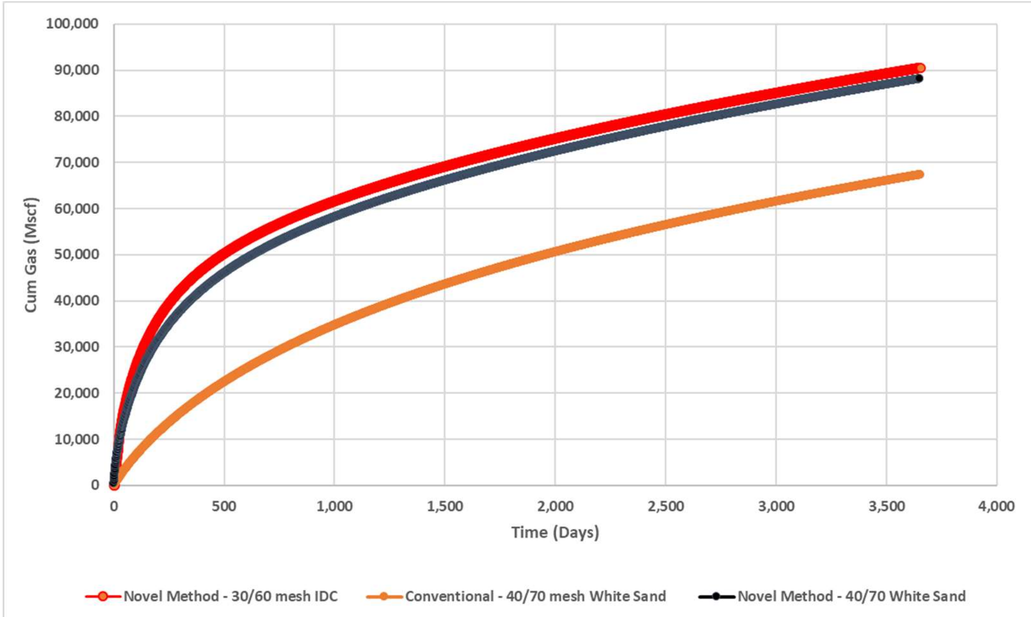

Figure 16— Cumulative gas production comparison between the three cases.

The simulated cumulative gas production for novel placement case 1 and case 2 are 34% and 30% higher respectively than the corresponding conventional method of case 3.

Similarly, **Figure 17** illustrates the same three simulated cases but for cumulative oil production. Deploying the novel method yields 36% and 32% higher than the corresponding conventional method for 30/60 IDC and 40/70 white sand respectively.

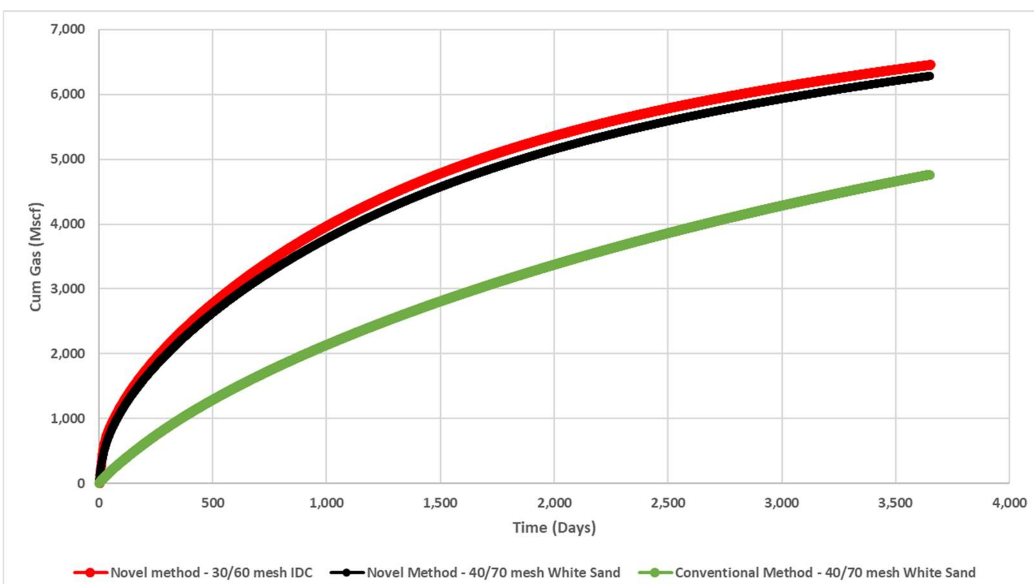

Figure 17— Cumulative oil production comparison between the three cases.

.

For additional reference this paper also includes in **Figures 18 and 19** the simulated sequential variations of the fracture conductivities and reservoir pressure for the Case 1, gas production case. Similar plots for the other cases were created as a part of each case simulation but they are not included in the paper.

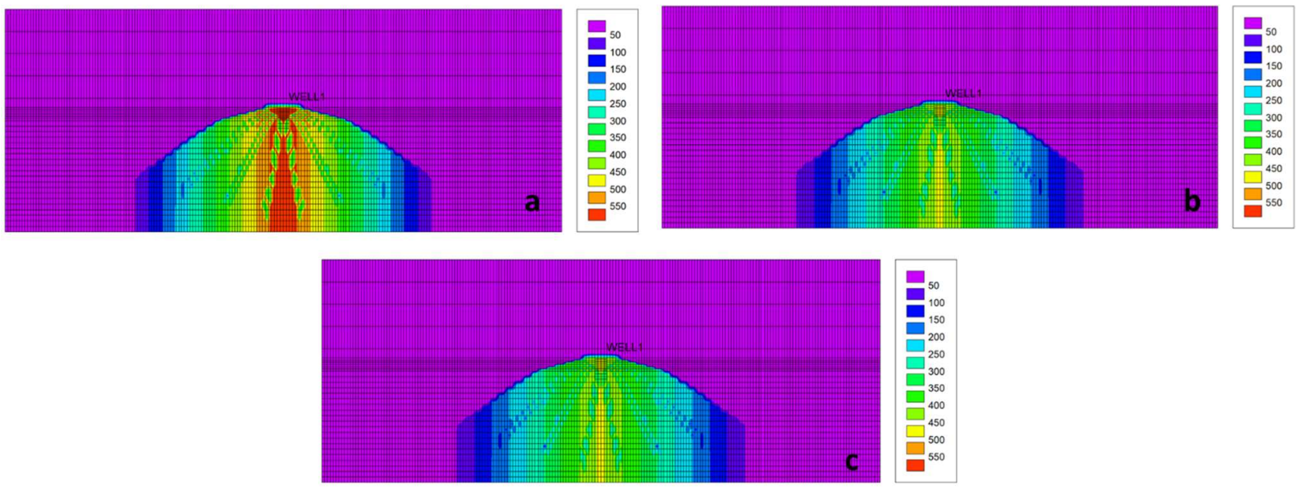

Figure 18— Novel method, Case-1, Gas producer, X-Z plane fracture conductivity time variation, 30/60 IDC Proppant. a) Initial conductivity, b) Conductivity at 1000 days and c) Conductivity at 3650 days

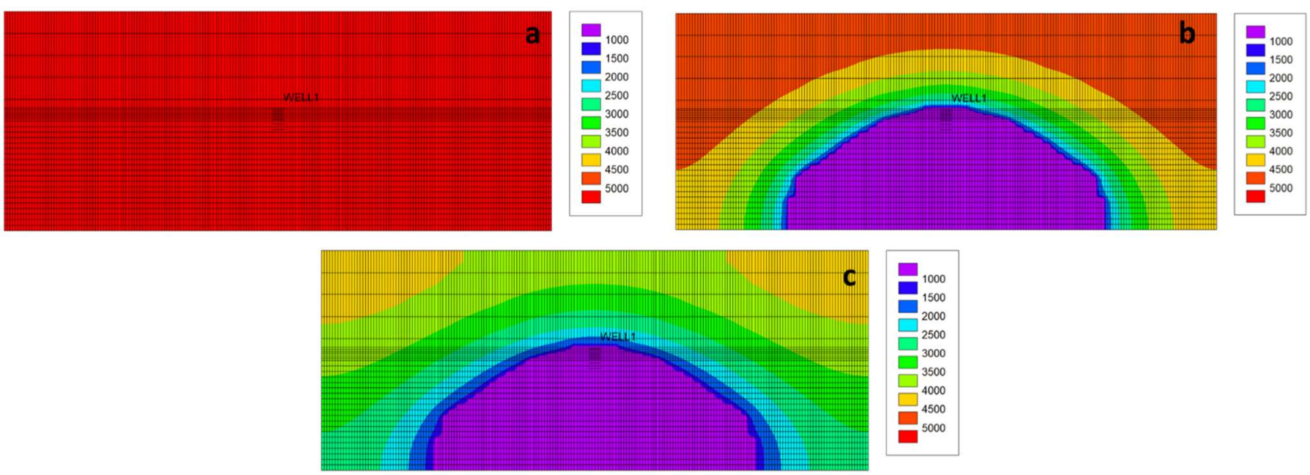

Figure 19— Novel method, Case-1, Gas producer, X-Z Plane Reservoir pressure time variation, 30/60 IDC Proppant. a) Initial pressure, b) Pressure at 1000 days and c) Pressure at 3650 days

Additional benefits or applications of the innovative proppant distribution improvement proposal

One inherent direct benefit of the proposed novel method is the generation of a bigger and more effective propped fracture using less carrying fluid volume compared with the conventional method, which translates into using less water.

Additionally the novel method can be used to stimulate and create conductive propped fractures in conventional reservoirs where different types of proppants can be placed selectively in specific areas of the generated fracture to improve the final well productivity. For example, a combination of non-coated and resin coated proppant on-the-fly or a combination of low- and high-quality proppants can be placed in the fracture to improve its conductivity or the downhole stability.

Conclusions

1. A proposed novel process improves vertical and lateral proppant distribution in fractures performed in unconventional gas- or oil-producing reservoirs.

2. Simulation results confirm the benefit of the novel proposed method to improve the gas-or oil-wells productivity and recovery factors.
3. The proposed method can be used in unconventional or conventional reservoir fracture stimulation purposes.

Acknowledgement

The authors acknowledge the support received from StrataGen, Halliburton and CARBO Ceramics management to prepare and present this paper.

Nomenclature

OLV	One Low Viscosity
RF	Recovery factor
sg	Specific gravity
ft	feet
in	Inches
Mgal	1000 gallons
Mscf	Thousand standard cubic feet
cPo	Viscosity, Centipoises
UR's	Unconventional reservoirs
IDC	Intermediate density proppant
Cum	Cumulative
RF	Recovery factor
nd	Nano-Darcy, permeability
PDI	Proppant distribution index
FR	Friction reducer

References

- Cipolla, C. L., Lolon, E., Mayerhofer. Michael J., Resolving Created, Propped, and Effective Hydraulic-Fracture Length. January 2008, SPE Production & Operations 24(4)
- Dontsov E.V., Peirce A.P. Incorporating Viscous, Toughness, and Intermediate Regimes of Propagation into Enhanced Pseudo-3D Model. Paper presented at the 49th U.S. Rock Mechanics/Geomechanics Symposium, San Francisco, California, June 2015. Paper Number: ARMA-2015-297
- Economides, Michael J.; Thomas, Ron L.,1989. Well Analysis Before and After Fracture Stimulation. SPE Paper 20153-MS. Prepared and presented at the SPE Centennial Symposium at New Mexico Tech, Socorro, New Mexico
- Economides Michael J. and Nolte Kenneth G. “Reservoir Stimulation” 3rd edition, published by John Wiley & Sons Ltd. Baffins Lane, Chichester, England.
- Osiptsov , A. A. (2017). Fluid mechanics of hydraulic fracturing: a review . Journal of Petroleum Science and Engineering 156 , 513 - 535
- Palisch, T. T., Vincent, M.C., et al, 2008. Slickwater Fracturing – Food for Thought. SPE Paper 115766-MS. Prepared and presented at the SPE Annual Technical Conference and Exhibition, Denver CO, 21-24 September
- Sierra L., Sahai R., Mayerhofer M., 2014. Quantification of Proppant Distribution Effect on Well Productivity and Recovery Factor of Hydraulically Fractured Unconventional Reservoirs, SPE paper 171595-MS. Prepared for presentation at the SPE/CSUR Unconventional Resources Conference—Canada held in Calgary, Alberta, Canada, 30 September–2 October 2014
- Sierra L., Eoff L., 2020. Propped Fracture Geometry with Continuous Flow. US Patent No. 10,808,515 B1
- Wang J., Elsworth D., Denison M. K., 2018. Propagation, proppant transport and the evolution of transport properties of hydraulic fractures. Article in Journal of Fluid Mechanics