ANALYSIS AND DIAGNOSTIC OF PROPPANT FLOWBACK IN THE ORITO FIELD, COLOMBIA

A. VARELA*, N. SAAVEDRA

Ecopetrol - Instituto Colombiano del Petróleo, A.A. 4185 Bucaramanga, Santander, Colombia
E-mail: rvarela@ecopetrol.com.co; E-mail: nsaavedr@ecopetrol.com.co

Hydraulic fracturing is a conventional practice for production enhancement in low production and damaged wells. Proppant flowback has been a concern in hydraulic fracturing since proppant began to be used as fracture supporting material. In order to prevent the usual proppant flowback problems, some wells in the Orito field were fractured using curable resin coated proppant (RCP). However, flowback production of proppant from some hydraulically fractured wells has caused some serious operational problems, demanding additional analysis of the problem and field handling procedures. This paper describes the laboratory tests and field considerations to design the tests, taken into account to analyze and diagnose the proppant flowback problem in the Orito field. Two types of tests were performed i.e., displacement and flowback.

El fracturamiento hidraúlico es una práctica convencional para el mejoramiento de producción en pozos de baja productividad y en pozos con daño. El retorno de proppant ha sido un tema de interés en fracturamiento hidraúlico desde que el proppant empezó a usarse como material de soporte de fractura. Con el fin de prevenir los problemas usuales de retorno de proppant, algunos pozos del campo Orito fueron fracturados utilizando proppant con resina curable (RCP). Sin embargo, retorno de proppant de algunos pozos fracturados hidraulicamente ha causado serios problemas operacionales, requiriendo algunos análisis adicionales del problema y ciertos procedimientos de manejo. Este artículo describe las pruebas de laboratorio y las consideraciones de campo tenidas en cuenta en el diseño de las pruebas, para el análisis y él diagnostico del problema de retorno de proppant en el campo Orito. Se realizaron pruebas de desplazamiento y de retorno de proppant.

Keywords: *hydraulic fracturing, proppant flowback, resin coated proppant (RCP).*

* *Corresponding author*

INTRODUCTION

Proppant flowback is a well-known problem related to hydraulic fracturing for more than two decades. The final goal in hydraulic fracturing is to create a highly conductive path for enchanced hydrocarbon production. This is achieved by preventing the fracture closure at the end of the job by using of a holding-up agent, like proppant. More than 15% of the proppant initially pumped can be returned after a treatment.

In fracturing operations, proppant is carried into fractures created when enough hydraulic pressure is applied to the rock strata to create a fracture. Proppant suspended in a viscosified fracturing fluid is placed into the fractures as they are initiated and extended with sustained pumping. Once pumping pressure is released, the proppant remains in the fractures holding the rock faces in an open position and in turn creating a better path for the flow of formation fluids into the wellbore. However, variations in the in-situ stress and the rock's mechanical properties usually lead to a uneven fracture closure.

Proppant flowback from propped hydraulic fractures causes tubing erosion, disposal inconveniencies and some other additional operational problems during the production life of a well. Higher proppant volumes are produced during the clean-up after a fracturing treatment and equipment is then available to handle the material produced to surface.

Two types of proppant flowback have been identified in the oil industry. The first occurs during the well clean-up phase just after the fracturing job, and the second after a long period of proppant free production. The first type is believed to be caused by a weak build of the proppant pack. The second type it usually happens due to stress cycling on the proppant pack (Figure 1).

Considerable work has been done in the industry to prevent, explain and control the proppant flowback problem.

INDUSTRY EXPERIENCE

Usual industry procedures to control flowback production of proppant are (Nguyen *et al.,* 1996; Martins *et al.,* 1992):

- Injecting a soluble resin to consolidate the proppant or supporting material in-situ.
- Installing a screen in the production string.
- Coating the proppant with a resin on site, In-fly technique.
- Using a resin-coated proppant (RCP) with a curable resin.

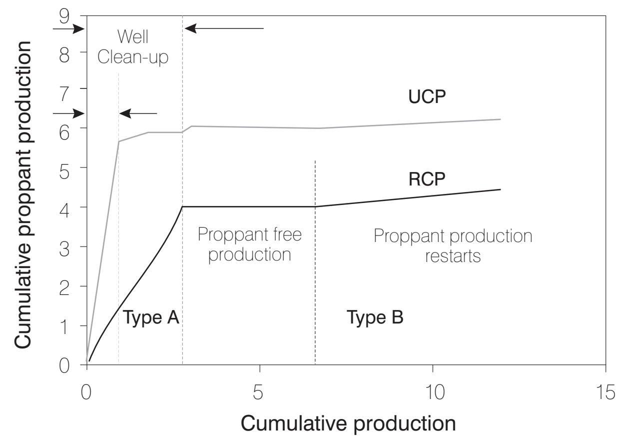

Figure 1. Typical proppant back production diagram

Regardless of the procedure used, high proppant volumes are usually back produced just after a well has been hydraulically fractured. An initial high production rate is followed by a long tail production (Figure 1). The proppant that is back produced while cleaning-up a well (Type A) can be divided into proppant that remained in the well and proppant from the created fracture. The latter possibly comes from the RCP pack, which did not develop enough consolidation strength. Its behavior is similar to that of an uncoated proppant (UCP). Common causes for this type of back production are insufficient grain-to-grain contact, low reservoir temperature, not enough resin reactivity, incompatibility with the fracturing fluids, and erosion of the resin from the base proppant (Barree *et al.,* 1995). Also shown in Figure 1 is a zone of proppant free production or production with no significant volumes of proppant on surface, but then the well begins to produce proppant again (Type B). Type B flowback production is usually due to stress cycling. The latter term refers to the stress the proppant pack has to sustain each time the well is shut down and put back on production. The applied stress increases as the drawdown is increased.

FIELD BACKGROUND

The Orito field is located in the Putumayo Basin of

Southern Colombia. The main producing interval is the Caballos formation. The first wells in the area were put on production in 1969; there are 83 wells with production data. Of these wells, 32 have been stimulated with 49 fracture treatments. A hydraulic fracture treatment was performed in the Caballos sand interval of the wells Acae-10 and Acae-11 on December 1997. The Acae-10 well had been recompleted to the Middle Caballos Sand in July 1996. The original completion in a lower Caballos section was abandoned due to excessive water production. Perforations in the recompleted interval were from 3,213 to 3,222m. (10,540 to 10,570 ft). The Acae-11 well was also completed in the middle Caballos sand with perforations from 3,242m to 3,256m. (10,638 to 10,684 ft). In both wells a mini-frac was performed prior to the main fracture treatment to determine critical fracture parameters i.e. total leakoff coefficient, instantaneous shut-in pressure, closure pressure, etc., necessary for 3D fracturing modeling. These results were then used to develop an optimized treatment design. The main fracture treatment was pumped according to the revised design schedule. In order to accurately predict the fracture geometry, it is critical to determine the in-situ stress profiles and mechanical properties (Young´s modulus and Poisson´s ratio) for the pay interval and the surrounding litologies that will be encountered by the fracture. The mechanical properties were determined by indirect measurement with an ultrasonic pulse from well logs. Once the Poisson's ratio is determined, it can be used to calculate the minimum in-situ stress gradient based on the following equation (Thiercelin and Plumb, 1991).

$$\sigma_{min} = \frac{v}{1-v}\left(\sigma_{ob} - \sigma_p\right) + \sigma_p \qquad (1)$$

Where,

σ_{min} = minimum in-situ stress, [psi/ft] / [Kpa/m]
v = Poisson's ratio [dimensionless]
σ_{ob} = Overburden stress, [psi/ft]/ [Kpa/m]
σ_p = Pore pressure gradient., [psi/ft] / [Kpa/m]

The in-situ stresses and the rock mechanical properties were used in the design of the proppant flowback tests, explained later on.

The material pumped to support the fractures was a RCP, and more specifically 20/40 resin coated ceramic proppant. This material was pumped as a mean to avoid the well-known proppant return problem (Almond *et al.,* 1995). Previous to the fracturing jobs, the wells were producing under artificial lift. The production rates increased as expected after the fracturing jobs. However, there were several replacements in the electric submersible pumping (ESP) units used as artificial lift system. The ESP units got stuck due to intrusions of proppant in the impellers, when the wells were shut down for work over. It is worth mentioning that the initial back production of proppant (Type A), in both wells was not excessive; it was within the expected ranges for treatments with similar characteristics (Cudney *et al.,* 1997).

EXPERIMENTAL PROCEDURES

In order to resemble the problems encountered in the field, two tests were performed i.e., displacement tests and proppant flow back tests. The data reported below should be taken as illustrative, since many factors come into play in the lab results, especially the source of the resin in the proppant.

Displacement Tests

The proppant pumped into the wells was supposed to be closure and temperature bonding curable. A closure stress of 1000 psi and a temperature of 200 °F 366 K (92 °C) were given as the curable conditions for the proppant to develop bonding between grains, for a period no lesser than 12 hours. Knowing the previous curing conditions, five core samples 3" long and 1.5" in diameter were mixed with the base fracturing fluid, then packed in a rubber sleeve and finally submitted to hydrostatic load above 1,000 psi and temperatures above 200 °F 366 K (92 °C) for at least 12 hours. There was no good adhesion between grains in any core.

The purpose of this test was to establish critical flow rates for the proppant back production in the worst scenario. That is, when there is no closure pressure applied on the packed beds; like proppant pockets, conglomerates of proppant in the vicinity of perforations and unconsolidated proppant at the upper layer of the proppant pack. In Figure 2 the experimental setup is shown. The equipment utilized for the displacement of fluids through the proppant cores was the AFS 200, equipment available at the Instituto Colombiano del Petróleo (ICP). The equipment is used in formation damage tests through direct and inverse flow of fluids like mud and acids. The tests were flow rate controlled.

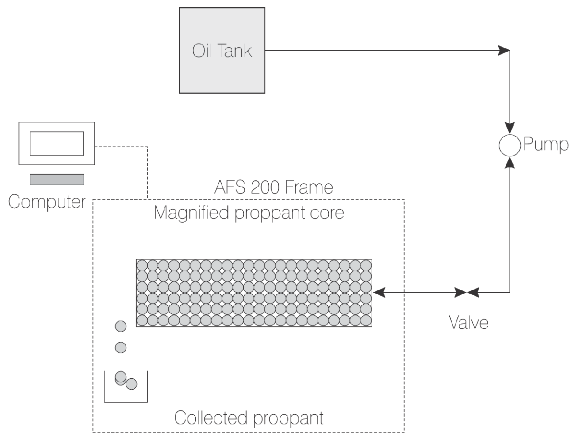

Figure 2. Experimental setup – Displacement tests.

The Lab-Field scaling can be described as follows. Based on mass conservation law, which states that fluid mass is always conserved, regardless of the medium complexity, flow orientation, and which fluid is flowing; it has been set:

$$Q = V \cdot A \tag{2}$$

For lab conditions:

$$V_L = k \frac{Q_L}{\pi \cdot r_L^2} \tag{3}$$

For field conditions:

$$V_F = k \frac{Q_F}{2\pi r_F \cdot h_F} \tag{4}$$

Equating the last two equations and solving for Q_F, it becomes:

$$V_L = k \frac{Q_L}{\pi \cdot r_L^2} \qquad V_F = k \frac{Q_F}{2\pi r_F \cdot h_F} \tag{5}$$

$$Q_F = k \frac{2 \cdot r_F \cdot h_F \cdot Q_L}{r_L^2} \tag{6}$$

Where[2],

r_F = wellbore radius [ft] / [m]
h_F = formation thickness [ft] / [m]
r_L = core radius [inch] / [m]
Q_L = Lab flow rate [cc/min] / [m^3/min]
Q_F = Field flow [bbl/day] / [m^3/day]
k = Units conversion factor.

Making the last equation dimensionally consistent and fixing the information for each well, the following scaling coefficient for Acae-10 is obtained:

$$Q_F = 7.31 \cdot Q_L \tag{7}$$

And for Acae-11:

$$Q_F = 9.71 \cdot Q_L \tag{8}$$

Cores 3.81 cm. (1.5 inches) in diameter and 15.24 cm (6 inches) long were used in the displacement tests. The cores were built inside a rubber sleeve; the proppant was mixed with the base fracturing fluid (borate fracturing fluid) and cured under simulated reservoir conditions of pressure and temperature (Kim *et al.,* 1985). The cure temperature refers to the temperature necessary to make the resin coating the proppant grains to react keeping the proppant grains together; in order to create a better flow path through the proppant pack. Despite making the cores under the conditions mentioned above, the cohesion strength of the proppant grains was still extremely low. Four displacements were carried out through the proppant cores. Table 1 shows the results obtained in one of the displacements. Figures 3 and 4 illustrate the results in the lab and then scaled to field conditions. The injection rate was progressively increased until proppant was produced at the end of the core. This critical rate was 60 cc/min in the lab. Scaling up to field conditions that would be 439 bbl/day for Acae-10 well and 582 bbl/day for Acae-11 well.

Proppant Flowback Tests

The flowback potential of the 20/40 resin coated proppant (RCP) was evaluated in a modified API conductivity cell (Penny, 1987). Proppant concentrations of 3.9 Kg/m^2 (0.8 lb/ft^2) and 7.3 Kg/m^2 (1.5 lb/ft^2) slurried with the borate fracturing fluid were used to conduct the tests. The evaluations were performed at 250 °F and 4,000 psi, as a mean to resemble reservoir conditions. The testing procedure was as follows:

- Place 65.4 cm^2 (10-inch^2), standard tests Ohio sandstone in the conductivity flowback cell. The cell has been designed with a removable insert at the flow exit that will make it a 1.27-cm (0.5-inch) opening (perforation simulation).

Table1. A lab displacement results.

Lab rate [cc/min]	Field rate [bbl/day]	Proppant back [grs]	Oil injected [cc]	Proppant [ppm]	[ppm] Cumulative	Field conc. [lbm/bbl]
0.1	1	0	15	0	0	0
0.2	1	0	16	0	0	0
0.3	2	0	20	0	0	0
0.4	3	0	20	0	0	0
0.5	4	0	40	0	0	0
1	7	0	40	0	0	0
2	15	0	55	0	0	0
4	29	0	70	0	0	0
8	59	0	80	0	0	0
16	117	0	90	0	0	0
32	234	0	200	0	0	0
60	439	1	590	1695	1695	0.6
120	877	0	600	0	1695	0.6

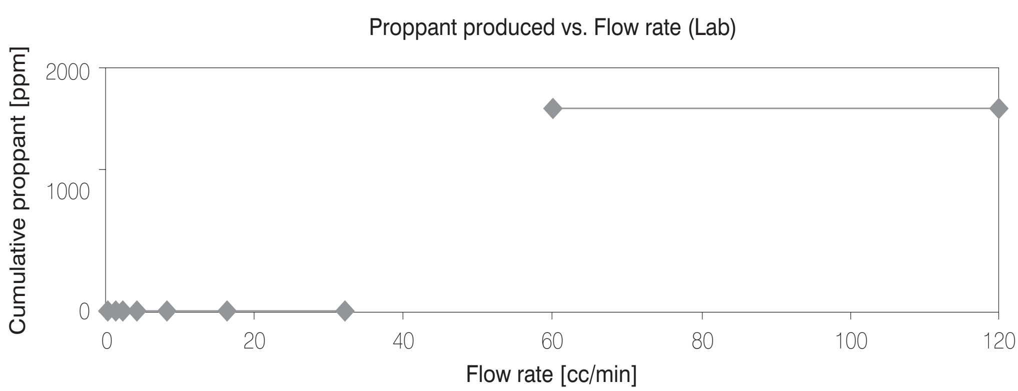

Figure 3. Lab critical flow rate.

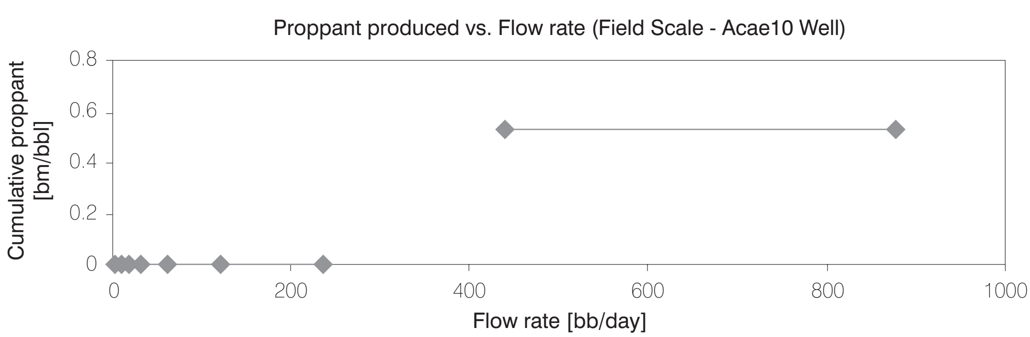

Figure 4. Critical flow rate- Field scaled.

- Mix 30 ml of the cross-linked borate fluid mixture with 48 grams of proppant (7.3 Kg/m^2 /1.5 lb/ft^2) or 25.6 grams (3.9 Kg/m^2 /0.8 lb/ft^2).
- Place proppant slurry in the cell and increase closure to $6.8 \cdot 10^5$ Pa (100 psi) and the temperature to 92 °C (200 °F). Temperature estimated with cool down during fracture stimulation.
- When 92 °C (200 °F) is achieved in 30 minutes, begin static leakoff stage. Open leakoff lines and start ramping temperature and closure over 90 minutes incrementally to the final target temperature and closure of 119 °C (250 °F) and $2.75 \cdot 10^7$ Pa (4000 psi) closure stress.
- After 90 minutes, shut cell in for 12 hours for fracturing fluid break time and resin cure time.
- Following the shut-in period, a 2% KCl fluid was regained through the cell for about 5 pore volumes to represent fracturing fluid return cleanup of the proppant pack after the well is opened and before the oil begins producing.
- Then, flow the mineral oil. The initial flow rate was 25 ml/min until flowback occurs or the maximum target flow rate was obtained. Coils of tubing were placed in a series of two baths to target the bottom hole temperature.

The inputs that were monitored for flowback detection are as follows (Figures 5 and 6):

Closure Stress (psi); this parameter will give one or two very notable deflections, which indicate proppant flowback point. In other words, the applied closure stress will suddenly increase due to the reduction of proppant grains in the proppant pack.

LVDT (Linear Variable Differential Transformer); measuring change in proppant pack width in mm. Again, there will be a very notable deflection point if proppant flowbacks. The proppant pack width will decrease if proppant grains go out of the pack.

Two temperatures were recorded for calculation of instantaneous viscosity and to make sure the mineral oil was flowing at bottom hole temperature.

Pressure drop (psi/5") through the pack was recorded using two pressure transducers, covering 9 psi delta pressure range. A sudden deflection in the dp curve is expected if flowback occurs.

Three pumps were used to stage the increases of flow rate from 25 ml/min to 1000 ml/min. The exit flow rate was measured to confirm the set target rates of the pump or combinations of pumps in use.

The final proppant measured width for the 3.9 Kg/m^2 (0.80 lb/ft^2) proppant pack was 0.22 cm (0.088 inches) and 0.40 cm (0.158 inches) in the 7.3 Kg/m^2 (1.5 lb/ft^2) case. Flowback was not observed in any case (see Figures 5 and 6). Although there is a steady rise in closure stress, it can be related to the pressure drop increase inside the proppant pack as the flow rate is increasing. The LVDT width change transducer, has also shown a slight increase with flow rate and time. Figure 7 shows an example case where width of the proppant pack changes at the point of flowback.

RESULTS AND DISCUSION

According to the displacement tests, the critical flow rates to obtain back production are extremely low, due to the low cohesive strength developed in the proppant pack. The proppant manufacturer set 92 °C (200 °F) as the cure temperature and 1,000 psi as the cure pressure for the RCP proppant supplied. It was not possible to make the resin to cure (keep together) the proppant grains with the flame nor the oven. Therefore, a poor quality of the resin coating the proppant grains, can be inferred. In addition to temperature, hydrostatic pressure was put on the proppant cores and no cohesion was obtained. Thus it is easy to understand why proppant can be back produced from propped fractures. Fractures that were placed with pad volumes that are too large or with resins that have poor curing capacity; will create loose proppant packs from bottom to top of the fracture. Proppant on the top of the packing will be easily carried out the fracture to the wellbore by the reservoir fluids.

Despite the low flow critical rates, scaled up from the lab to field conditions, necessary to back produce the proppant, just a few proppant grains in the impellers have been enough to damage the ESP units, due to the high compressive resistance of the proppant grains, i.e., $6.8 \cdot 10^7$ Pa (10,000 psi). That is why, it has been recommended an artificial lift system with no mobile parts. The low amounts of proppant produced are kept in suspension while the ESP units are working; once the wells are shut in for work over the particles settle down in between the impellers and pump's wall due to gravity forces. When the wells are put back on production (stress cycling) the settled proppant particles

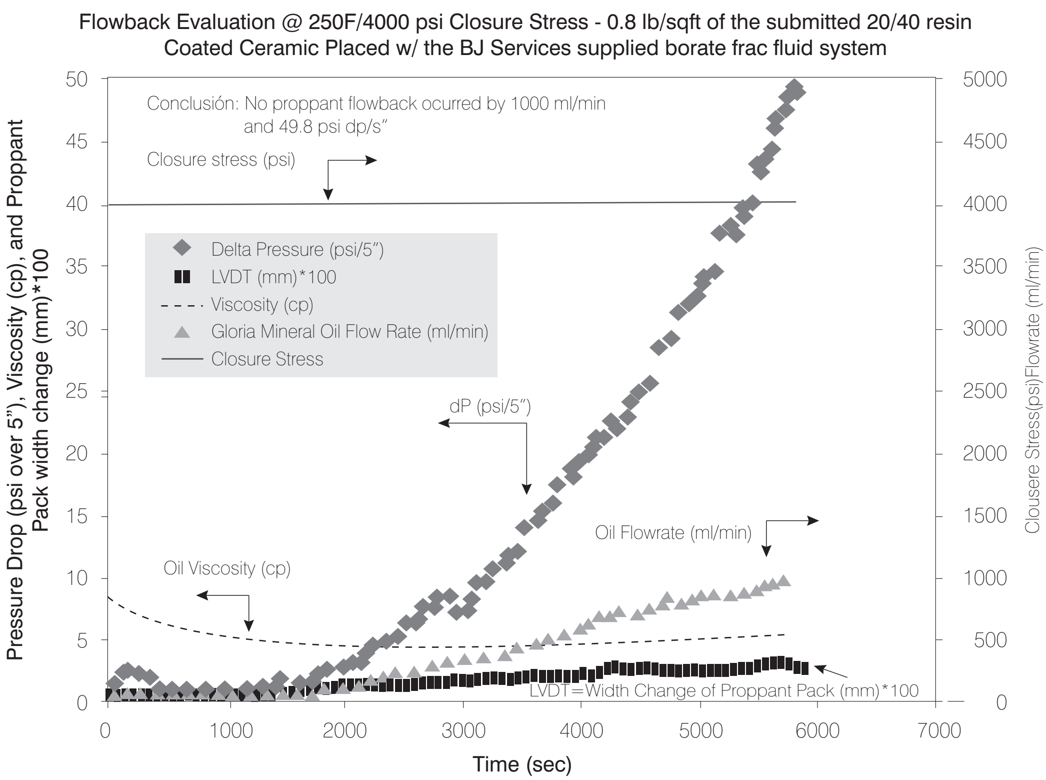

Figure 5. Flowback evaluation. 0.8 lb/ft^2, 20/40 RCP.

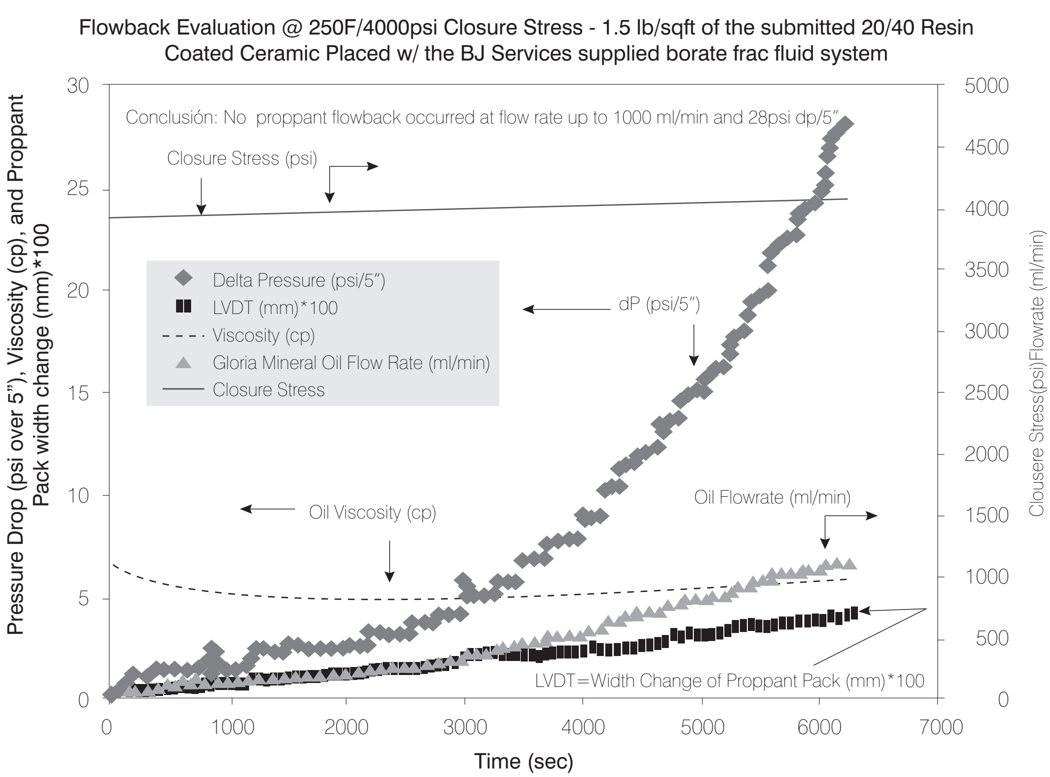

Figure 6. Flowback evaluation.1.5 lb/ft^2, 20/40 RCP.

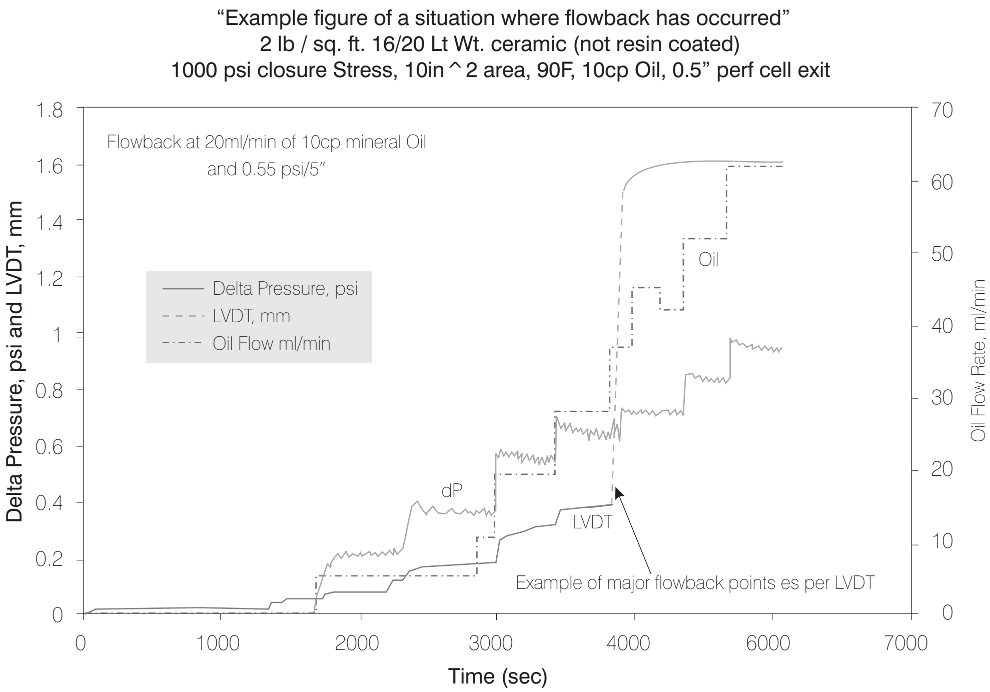

Figure 7. Example of proppant flowback detection in the API cell.

will stock the ESP impellers.

The proppant flowback tests show no back production of proppant. According to the estimated in situ stress gradients and rock mechanical properties, the fractures once created will have a high closure stress. This explains two facts. The first is that, the formation stresses are those which keep the proppant grains together; explaining the low amounts of proppant produced in the field regardless the poor resin quality. The second, being that no flowback was detected even with high flow rates during the tests. This is due to the uniform proppant packing in the cell, which will not be developed in a real fracture; where the fracturing fluid or the well fluids will encounter pockets of high proppant concentration. These pockets favor proppant transports even at low flow rates.

Figures 8 and 9 show an impeller damaged by the carbolite utilized in the Acaé-11 frac job. A crack was created on the impeller axes and a couple of notches.

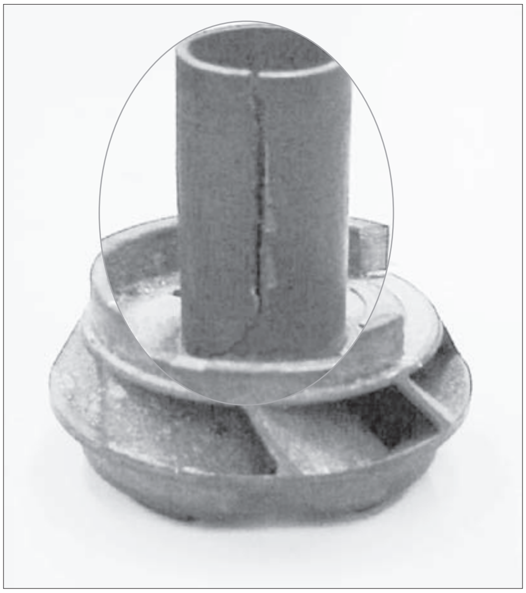

Figure 8. Impeller damaged by used carbolite (Acaé-11).

According to previous micrography analysis done by Benavides and Pachón (1998), quartz grains are embedded in the cementing material which includes ferrous oxides and silicate aluminum among others (Figure 10). From Figure 11, which corresponds to an spectrum, chromium and nickel have been provided by the impeller, those two elements were dragged by the carbolite grains. Figure 12 shows a micrography on a carbolite grain, which had lost its spherical shape and roundness due to the scratching with the pump walls.

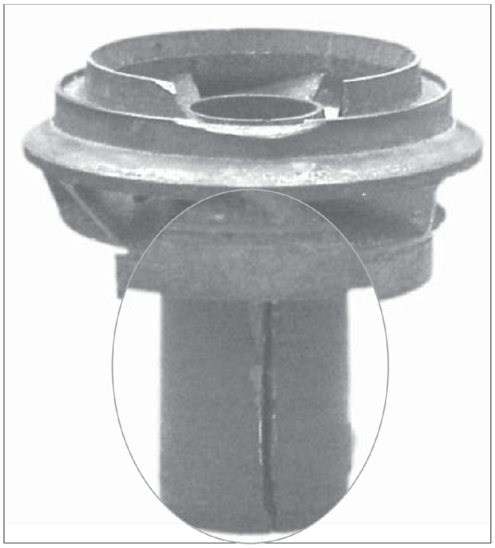

Figure 9. Notches created by the carbolite (Acaé-11)

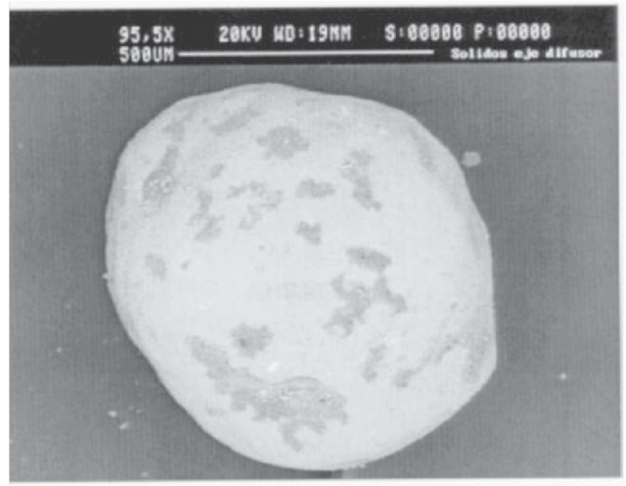

Figure 12. Micrography in an individual carbolite grain.

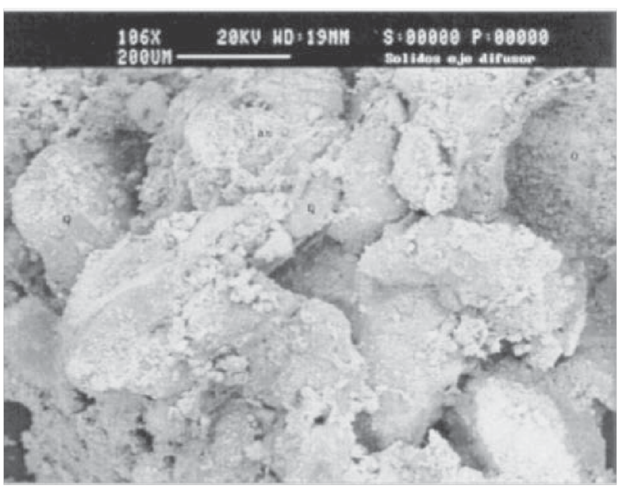

Figure 10. Micrography image, solid material in the impeller

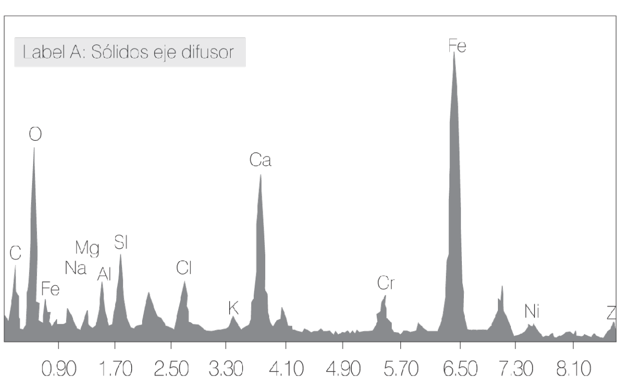

Figure 11. Spectrum of Carbolite grains.

CONCLUSIONS

Conclusions 5 through 8 are supported mainly by field personnel observations and are in accordance with the performed tests.

- Displacement tests performed in unconfined cores represent the worst scenario of well conditions in which there was no closure pressure applied on the packed beds.

- The resin coating the proppant did not work as expected. Although high confining pressures and high temperatures were used in the preparation of the cores; an extremely weak cohesive strength was developed among the proppant grains.

- In this case areas of high proppant concentration, i.e., above 7.3 Kg/m^2 (1.5 lb/ft^2) are zones prone to flowback.

- As the reservoir fluid (or fracturing fluid during cleanup) moves through the bed of proppant, it can, with enough velocity, pick up the upper layer of unconsolidated proppant, move it to the wellbore or settle it in some fracture cavities.

- The two typical causes of proppant flowback were identified. The first one, the failure of resin bonds between the proppant grains. The second one, stress cycling. The effective stress on the proppant pack is cycled each time the wells are shut down and then put back on production, or even when it is just beaned up or down.

- Cycling of well production due to the closing of the well down to work it over and then opening back up immediately to its previous choke setting, it certainly creates a rapid initial production rate which affects the proppant pack stability.
- High instantaneous flow rates upon the point of reopening could mobile small amounts of proppant, especially in areas of higher concentrations than 7.3 Kg/m^2 (1.5 lb/ft^2).
- During workover, brine water can accumulate in larger than average volumes, and then when the well is rapidly open, the initial two-phase flow of larger volumes of brine water with the oil can create proppant flowback at the interface.

ACKNOWLEDMENTS

The authors would like to express their thanks to the following people: Javier Nevito and Andrés Lopez from GSU, Nelson Aldana from KTP and Carlos Estrada from GYA; who contribute in analyzing other areas of the flowback problem which are not included in the present article.

REFERENCES

Almond, S.W., Penny, G.S. and Conway, M.W., 1995. "Factors affecting proppant flowback with resin coated proppants", *SPE* 30096.

Barree, R. D., Mukherjee, H., 1995. "Engineering criteria for fracture flowback procedures", *SPE* 29600.

Benavides, C. C., Pachón, Z., 1998. "Análisis composicional de sólidos encontrados en el impeler de la bomba electrosumergible de Acae 11". *ICP-KEX* (CR 212.411.5). Internal Publication.

Cudney, G., El-Moniem, H., 1997. "High permeability fracturing with a unique proppant flowback prevention technique", *SPE* 37733.

Kim, C. M., Losacano, J. A., 1985. "Fracture conductivity damage due to crosslinked gel residue and closure stress on propped 20/40 mesh sand", *SPE* 14436.

Martins, J. P., Abel, J. C., Dyke, C. G., Miche, C. M. and Steward, G., 1992. "Deviated well fracturing and proppant production control in the Pruhoe Bay Field", *SPE* 24858.

Nguyen, P. D., Weaver, J. D., Parker, M. A., King, D. G., Gillstrom, R. L., and Batenburg, D. W., 1996. "Proppant flowback control additives", *SPE* 36689.

Penny, G. S., 1987. "An evaluation of the effects of environmental conditions and fracturing fluids upon the long term conductivity of proppants", *SPE* 16900.

Thiercelin, M. J., Plumb, R. A., 1991. "A core-based prediction of lithologic stress contrasts in east Texas formations", *SPE* 21847.