SUCCESSFUL IMPLEMENTATION OF DISSOLVABLE FRAC PLUGS IN HORIZONTAL VACA MUERTA SHALE WELL IN ARGENTINA

Esteban Ariel Pach, Martin Fernandez Costagliola, Russell Wittig, Yvan Simmons, Halliburton,
EstebanAriel.Pach@halliburton.com

Synopsis

The Vaca Muerta shale in Argentina is a growing focus area for unconventional resource development in Latin America. Operators are evaluating the most effective completion solutions to successfully perform hydraulic fracturing and to produce the formation while reducing overall well completion costs. Typical unconventional completion designs use mechanical isolating plugs and multiple perforation clusters in each interval to effectively treat and isolate each stage during fracture stimulation.

This technique, known as plug-and-perf (PnP), typically requires intervention to drill out the plugs in one or more trips, using a mill or tricone bit deployed on coiled tubing (CT) or jointed tubing. Although this procedure increases operational cost and risk, it is even more expensive and risk-prone in the Vaca Muerta basin where many wells have problems with casing collapse that is believed to be caused by geological shifting.

In an ongoing effort to reduce the associated intervention costs incurred when completing a well using the PnP method, it was essential to determine a means of eliminating the need for post-fracture drillout operations. The objective of maintaining the frac plug parameters and customer requirements during pumpdown and setting operations added to the challenges.

A novel dissolvable frac plug (DFP) technology was used in a horizontal wellbore in the Vaca Muerta shale in western Argentina. To begin, a 5 1/2-in. (139.7 mm) monobore casing was run and cemented in place. DFPs were deployed by means of traditional PnP completion techniques to enable multizone hydraulic fracturing. The DFPs were successfully deployed using electric wireline; perforations created formation access. Fracture stage isolation was successful with each DFP.

After successfully completing the 15 stages, which required standard wireline installation equipment and pump down procedures, the plugs fully dissolved, eliminating the need for post-stimulation intervention. The well was flowed back and placed on production without completing a CT mill out, which exceeded operator expectations.

To validate the technology in the Vaca Muerta formation, the customer elected to run CT after four weeks of production to physically verify that the technology had dissolved as designed. There were no indications of plug remains, and production returned to the same values as before the intervention.

This case study illustrates the viability of this type of technology in the Neuquén basin by reducing risks and completion costs through the elimination of post-fracturing wellbore CT intervention; it also enabled the well to be brought on production more quickly than with conventional technology.

Introduction

In Argentina, Vaca Muerta shale is playing a crucial role in unconventional development. As such, operators are constantly evaluating how to produce at lower cost while using same or similar intervention techniques. The most commonly used technique in this region is plug-and-perf (PnP), which consists of pumping down a composite plug to a desired depth with wireline, setting the plug, making the perforations, and fracturing. After this, coiled tubing (CT) is used to mill all composite plugs to provide a full wellbore ID to produce the well.

The use of CT introduces an operational risk specifically in Vaca Muerta where many collapsed wells have been observed. Moreover, operators must extend lateral section of wells to maximize contact with formation, which requires CT capable of operating at these technical requirements.

These three challenges resulted in the need for introducing a technology that would avoid the use of CT. The objective of this work is to describe the experience using dissolvable frac plug (DFP) in a horizontal wellbore in the Vaca Muerta shale in western Argentina.

Challenge

The current PnP operations in Vaca Muerta wells deliver, in the best case, five stimulated stages per day when completed in simultaneous operations (SIMOPS) in multi-well pads. On average, mill out operations in 1,500 to 2,000 m laterals with 15 to 20 fracturing stages require between three and four days (Figure 1).

Figure 1. Current estimation of PnP operations duration in Vaca Muerta wells.

One of the primary challenges of the Vaca Muerta formation lies in its stress anisotropy. In some cases, while performing SIMOPS in a well pad, one well is stimulated while mill out operations are conducted in a nearby well. Casing collapses have been known to occur during mill out operations (trapping the CT string), which are caused by stress adjustments after the stimulation in nearby wells. A casing collapse has the potential to trap a CT string or block the access to mill out the frac plugs. In some occasions, the problem is addressed by stopping the SIMOPS in a well when a mill out trip is being performed in a nearby well.

In addition, the needs to increase efficiency and the stimulated reservoir volume (SRV) and to reduce costs result in longer laterals. Many companies are drilling wells in which the lateral length exceeds 2000 m; some of those companies are working to reach 3000 m lateral length.

The increased lateral length creates additional frictional drag while the CT is moved toward the toe of the well; consequently, less weight on bit (WOB) is available to drill/mill out frac plugs. It also results in a technical limitation to reach total depth (TD), considering the current CT equipment available in the country.

Although the operational efficiency of the PnP method is reaching a plateau, the need to conduct expensive, risky, and time-consuming post-stimulation intervention still exists.

Recently, innovative dissolvable material technologies have been adapted to the oil field to eliminate the need to perform CT or jointed pipe intervention to remove the frac plugs used during the stimulation process. By using this technology, up to 35% of PnP duration can be saved, directly resulting in reduced operational costs and reduced intervention risks associated with the CT operation.

Background

In the early days of multistage stimulation, zonal isolation was accomplished by the use of sand plugs or retrievable bridge plugs. By the end of the 1990s, composite bridge plugs were used. To accompany horizontal wells implementation, the technology evolved to include pump through composite frac plugs, a cutting-edge technology that is now fully implemented. The need arose to conduct a post-stimulation mill/drill out trip to remove all frac plugs in one trip. Since then, two primary schools of thought related to frac plugs drill/mill out operations emerged. The first focused on optimizing the mill out operation; the second targeted the complete elimination of the drill/mill out intervention.

Composite materials with enhanced drillability, as well as improvements in drill/mill out techniques using CT were implemented (Ahn, 2015; Pawlik et al., 2014) to reduce the amount of time required for the removal operation.

Conversely, attempts to obtain a reliable and economic self-removing frac plug have been made since 2006; a self-removing frangible bridge plug (Figure 2) that disintegrates into pieces and falls as debris into the rathole was proposed and tested in vertical wells located in Wyoming, USA (Swor and Sonnefeld, 2006).

Figure 2. Frangible bridge plug (left) and leftovers after desintegration (right).

From the frangible bridge plug, the technology continued to evolve to the big bore frac plugs (BBFPs). BBFPs partially solved the problem because, as a result of their large inner diameter, it was possible to produce the well (when used with dissolvable frac balls, allowing sufficient time for the balls to dissolve) through the plugs without causing a noticeable pressure decrease across their interior. However, the BBFPs produce a wellbore ID reduction that can cause possible limitations for subsequent interventions in the life of the well.

The implementation of dissolvable materials technology in stimulation operations can be traced back to 1998 when Water Soluble Perforation Ball Sealers (made of collagen) were used to divert stimulation fluids flow (Bilden et al., 1998). Recently, the development of dissolvable metals, initially used as raw material to manufacture frac balls,enabled the development of dissolvable metal systems that required landing profiles (receptacles) as part of the casing/liner string (Aviles et al., 2015). This solution eliminated the need for a post-stimulation mill/drill out trip because the entire system dissolves after stimulation. However, it resulted in complications associated with the considerable number of receptacles that must be run as part of the casing string; it also lacked the characteristic versatility of PnP operations regarding the selection of the setting point of zonal isolation devices.

Recently developed dissolvable rubbers (Takahashi et al., 2015) have enabled the implementation of dissolvable frac plugs that combine the proven benefits of conventional frac plugs and the convenience of dissolvable materials technology.

Dissolvable Frac Plug

A dissolvable frac plug (Figure 3) is a revolutionary isolation device that is similar to the frac plugs currently used extensively in the oil and gas industry, but with the additional benefit of being self-removing.

The dissolvable frac plug consists of five main parts:

- Slips: made of dissolvable metal alloy and ceramic composite buttons; provide and ensure the necessary grip during setting and fracturing.

- Mandrel: made of dissolvable metal alloy; holds the plug components, provides the required passage to pump fluids through the plug, acts as a ball seat for the dissolvable ball, and functions as the link with the setting tool adapter kit.
- Rubber element: made of degradeable rubber; provides the hydraulic isolation after setting (on the annulus side).
- Mule shoe: made of dissolvable metal alloy and ceramic composite buttons; guides the dissolvable frac plug during deployment. During flow back of the well, it prevents the ball from the previous stage from entering the mandrel.
- Wedges: during the setting process, compress rubber element and drive the slips against the casing wall.

Figure 3. Dissolvable frac plug.

The degrading materials used in the DFPs have been selected for their degrading properties, reliability, and performance. Degradable metals use variations of local galvanic corrosion to achieve controlled dissolution (Fripp and Walton, 2016). Galvanic corrosion occurs when two (or more) dissimilar metals are brought into electrical contact under wellbore fluid. When a galvanic couple forms, one of the metals in the couple becomes the anode and corrodes more quickly than it would alone; the other metal becomes the cathode and corrodes more slowly than it would alone.

The driving force for corrosion is a potential difference between the different materials. Figure 4 shows standard potential of engineering metals, which indicates that magnesium is a good metal to serve as a base (anode). The overall corrosion reaction is:

$$Mg + 2H_2O \rightarrow Mg(OH)_2 + H_2$$

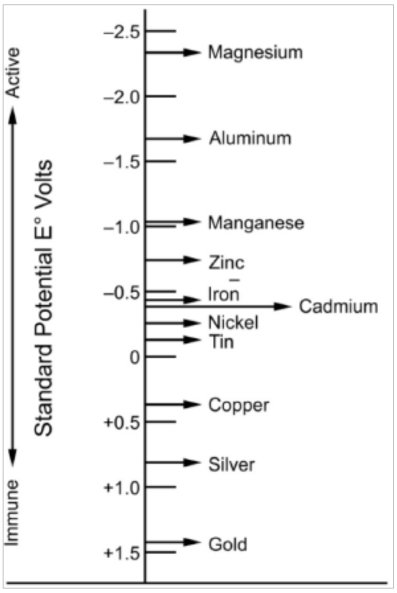

Figure 4. Standard potential of engineering metals.

A cathode phase is created by adding a dopant, such as zinc, iron, nickel, tin, cooper, silver, titanium, gold, or graphite. The various compositions and concentrations of the cathodic dopant will affect the dissolution rate (Fripp and Walton, 2016).

The elastomer is dissolved by hydrolytic degradation in which polymers are broken down into monomers when in contact with water. The reaction breaks the bonds of sensitive links in the polymer chains. As a result, the elastomer will gradually weaken during the hydrolytic degradation. A dissolvable element of a 5 ½-in. frac plug will degrade into a gel after a week at 93 °C (200 °F) and 5,000 psi (34.5 MPa) hydrostatic pressure. After seven days, the parts are easily separated with minimal force and have consistency of grease (Fripp and Walton, 2017).

The dissolution speed (accelerating the galvanic corrosion reaction) of the dissolvable material is a function of downhole temperature and surrounding fluid salinity; the greater the temperature and salinity, the faster the dissolution rate. Figure 5 and Figure 6 show the change in dissolution rate as a result of temperature (from 220°F to 240°F) and in salinity (30,000 ppm, 50,000 ppm, and 70,000 ppm).

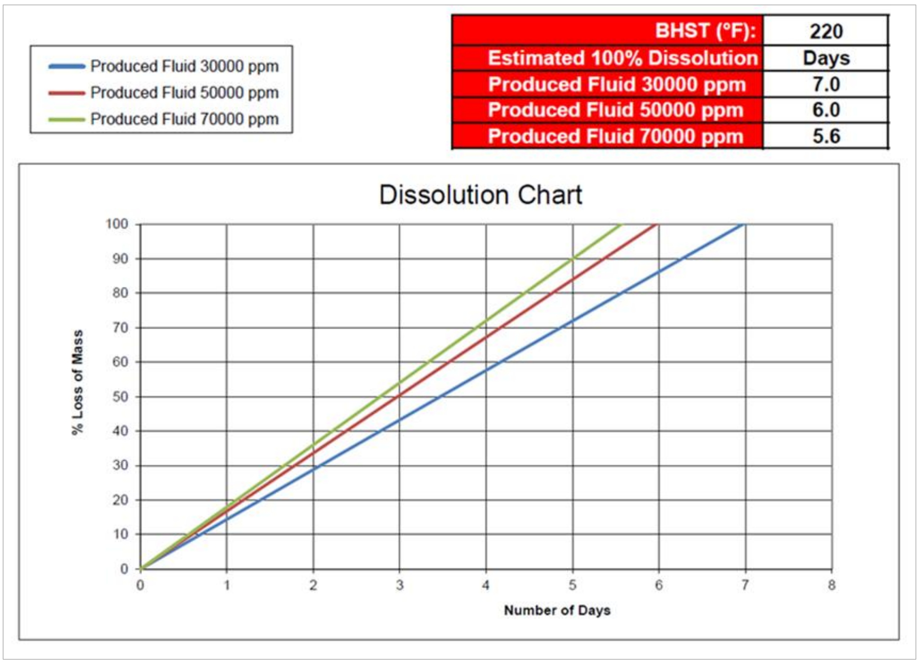

Figure 5. Dissolution chart for 220°F (104 °C).

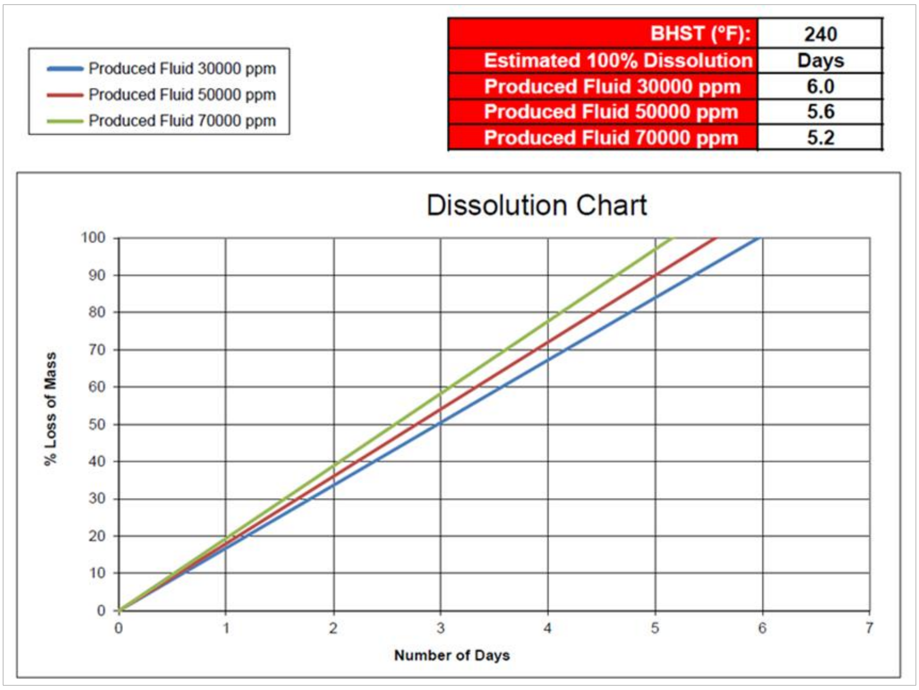

Figure 6. Dissolution chart for 240°F (115 °C).

The DFP can be deployed using conventional wireline practices and can be run using traditional pyrotechnic or electric setting tools run on wireline. An analysis is made before running in hole to determine the actual differential pressure that the DFP will encounter. In the extreme event of needing to hold 10 ksi of differential pressure, the best performance during stimulation will be obtained by decreasing the well temperature at a value of 150°F. Reducing the wellbore temperature usually does not require an additional operation; this occurs as consequence of pumping down tools and the hydraulic stimulation of previous stages.

When DFPs are used, the following steps are performed:

1. Plug is connected to the wireline setting tool using the respective adapter kit and then run in hole (RIH) at speeds of up to 500 ft/min (152 m/min). Pumping is used to assist in the RIH operation in the horizontal lateral section (Figure 7).
2. After reaching the setting depth, the setting tool is activated; the DFP is set and detached from the setting tool (Figure 8). Guns are then activated to create the perforation clusters.
3. Wireline is pulled out of hole (POOH).
4. A dissolvable ball is displaced downhole to land on top of the DFP to isolate the previous stage. The stimulation is then conducted after confirmation that the ball has landed (Figure 9).
5. After all stimulation stages have been completed (from toe to heel), the well is flowed back or shut-in. In the meantime, the ball and plug materials are dissolving (Figure 10).
6. The well is then produced, and the DFP continues to degrade in accordance with temperature and salinity conditions (Figure 11).
7. The full bore clearance is reached after sufficient time has elapsed for the DFP to completely dissolve (Figure 12).

Figure 7. Pumping down the DFP.

Figure 8. Setting the DFP.

Figure 9. Ball pumped down and stimulation performed.

Figure 10. Well is allowed to flow back. Temperature and salinity begin the dissolution process of ball and DFP.

Figure 11.Well is allowed to flow back. Temperature and salinity increase accelerate the dissolution process of the frac ball and DFP.

Figure 12. Full wellbore clearance is achieved after total DFP dissolution.

Case Studies and Results

DFPs were used in a horizontal well that consisted of 15 fracture stages. The first communication with the formation was performed using a toe sleeve to pump down the bottomhole assembly (BHA) to perform the first perforations without the use of CT.

Figure 13 shows the well schematic; Table 1 show well parameters; Table 2 provides the final plug and perforations depths per stage.

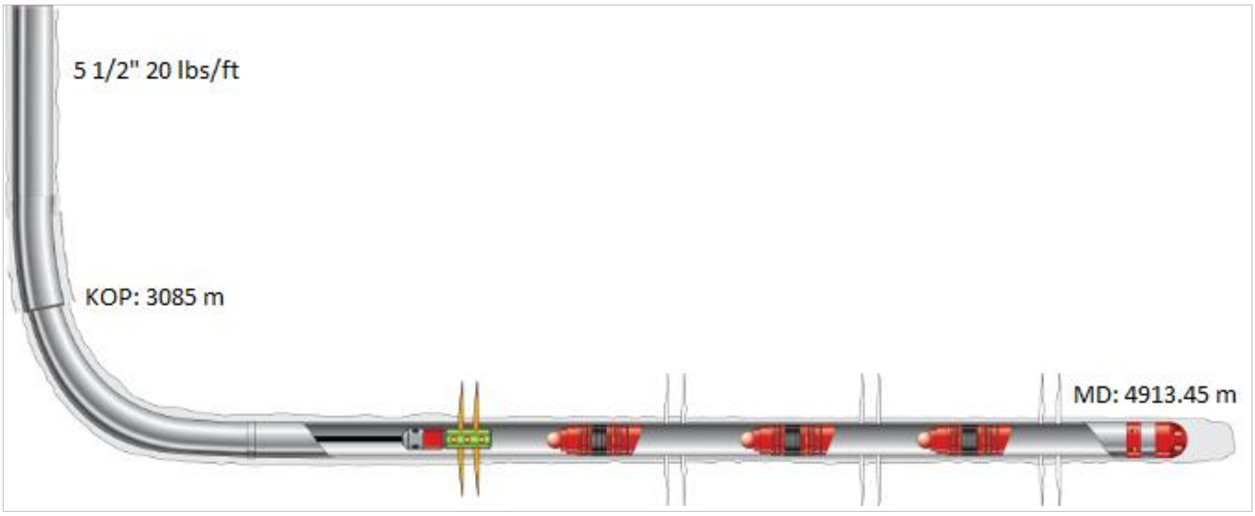

Figure 13. Completion schematic.

Well Information	
Property	Description
Well Type	Producer
Production Liner	5 ½", 20#, P-110, TSH-563. ID: 4.778"
Total Depth	4913 m (16,120 ft) MD
Maximum Inclination:	Horizontal
Completion Fluid	Fresh water, 8.34 ppg
BHT	240 °F

Table 1. Well information.

Stage N°	Plug Depth (m)	Cluster 1 Depth (m)	Cluster 2 Depth (m)	Cluster 3 Depth (m)
1		4745	4711	4677
2	4649	4639	4620	4593
3	4570	4560	4538	4513
4	4460	4456	4425	4395
5	4371	4364	4328	4295
6	4279	4272	4228	4185
7	4167	4160	4120	4090
8	4067	4060	4030	4000
9	3982	3973	3946	3910
10	3882	3875	3846	3822
11	3787	3780	3750	3725
12	3707	3700	3672	3650
13	3632	3625	3602	3575
13 bis	3630	3624.5	3601.5	3574.5
14	3542	3535	3505	3475
15	3462	3455	3429	3405

Table 2. Plug and cluster depths per stage in meters

Note: because of the inability to fracture stage 13, extra perforations were made 0.5 m above each cluster. Another plug (13 bis) was set 2 m above the existing plug.

RIH Parameters: Pump Down Operation

The parameters reached during the RIH process include the following:

- Line speed: 81 to 122 m/min (267 to 400 ft/min)
- Pump rate: 15 to 18 bpm (2.38 to 2.86 m^3/min)

Figure 14 shows the pump down capabilities of the dissolvable frac plug model; the area shown in green is the safe zone to pump down the DFPs. The by-pass flow rate capability is comparable to that of conventional frac plugs and exceeds most of them; this result demonstrates that there is no limitation on the PnP operation using DFP.

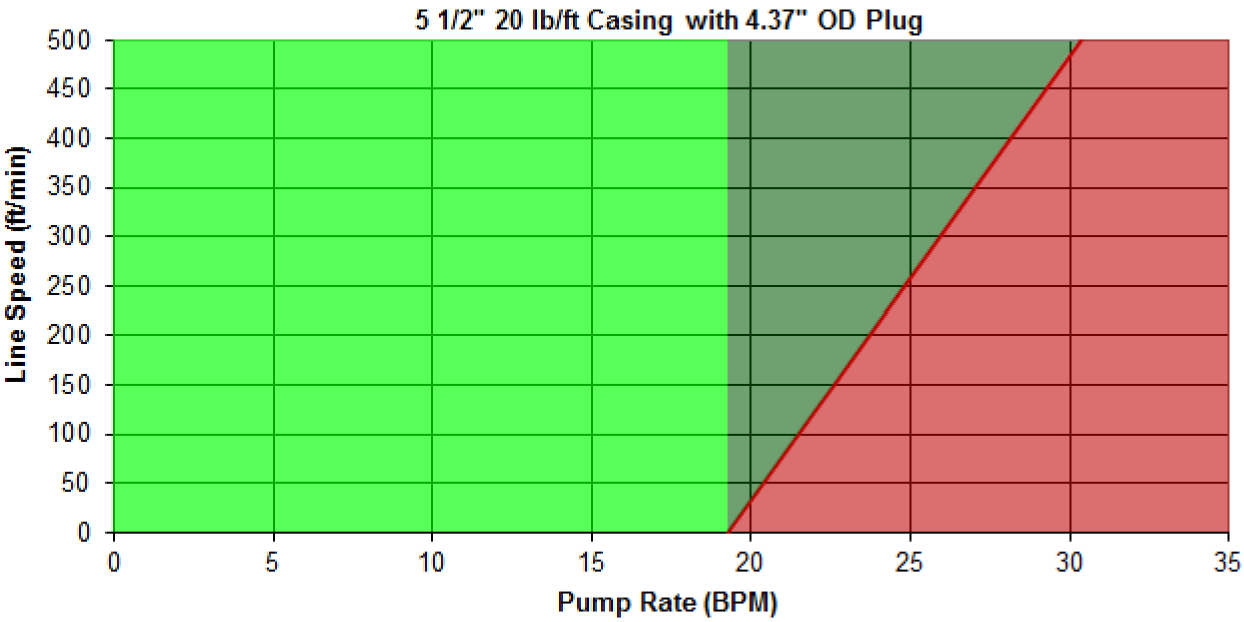

Figure 14. Pumpdown flow rate vs. line speed.

As an example, Figure 15 shows a stage pumpdown chart, pumping the plug at 18 bpm (2.86 m^3/min), shutting down the pumps at depth, and pumping back at 3 bpm (0.47 m^3/min) to perform the perforations.

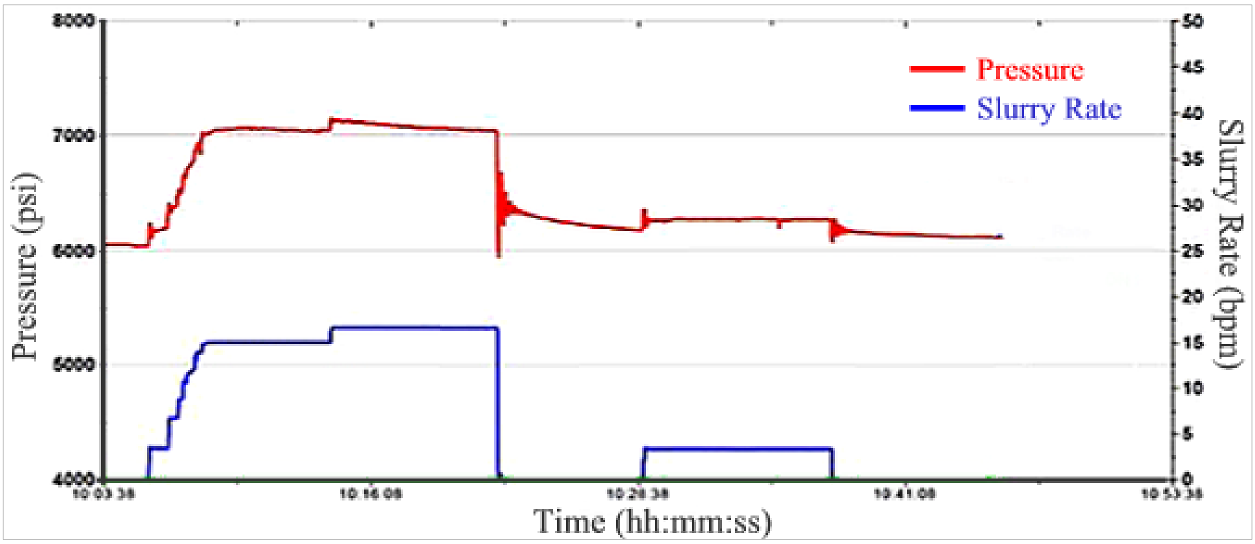

Figure 15. Pumpdown chart

Figure 16 shows the RIH times during all PnP stages. The values represent the time since wireline begins the DFP RIH operation until the DFP is set.

An pyrotechnic setting tool was used to set the plugs. All plug set operations were successful. An assessment at surface indicated the loss in line tension and provided a visual check of the setting tool.

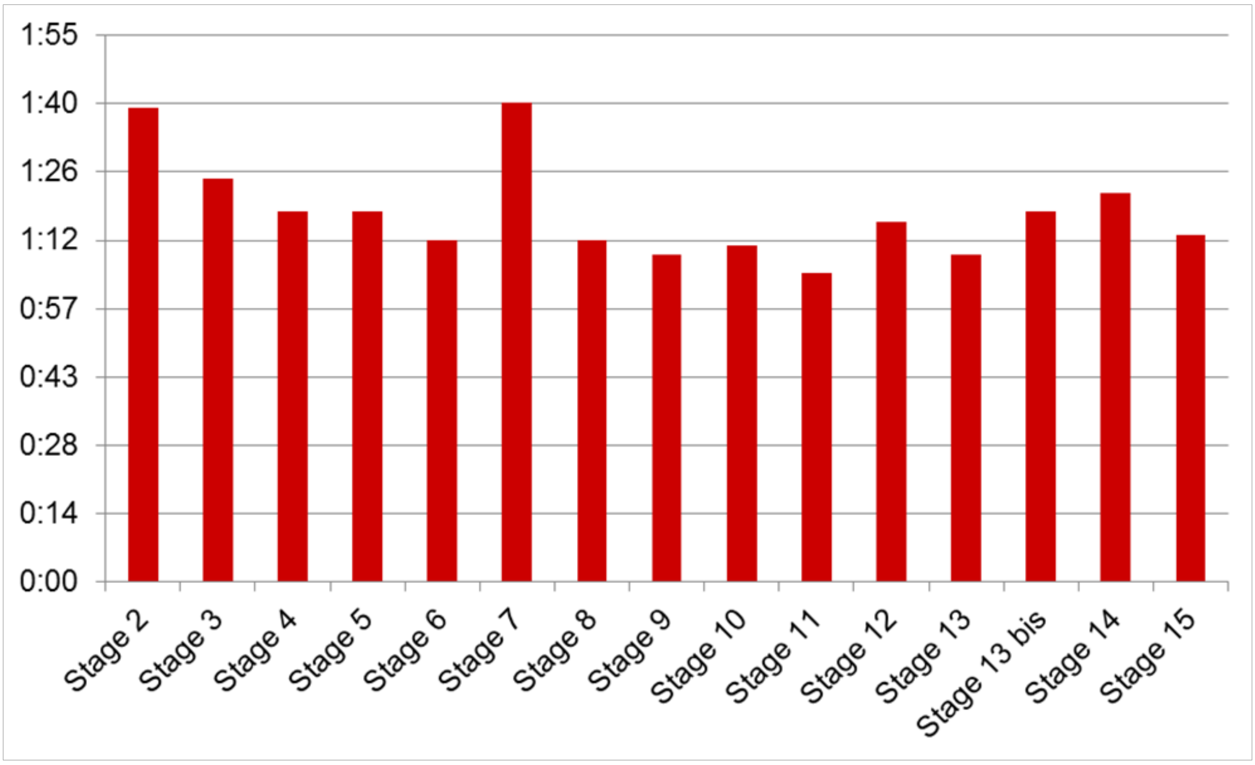

Figure 16. Time to run in hole of DFPs.

Hydraulic Fracturing

Dissolvable balls were pumped using fresh water at 20 bpm (3.18 m^3/min). At 30 to 40 bbl (4.77 to 6.37 m^3) before the theoretical volume to land the ball on the plug, the pump rate was reduced to 12 bpm (1.91 m^3/min) to observe the ball landing pressure signature. After ball landing event confirmation, acid was pumped to begin the fracture job.

As an example, Figure 17 shows a fracture stage, including the ball landing, acid job, and beginning of stage stimulation.

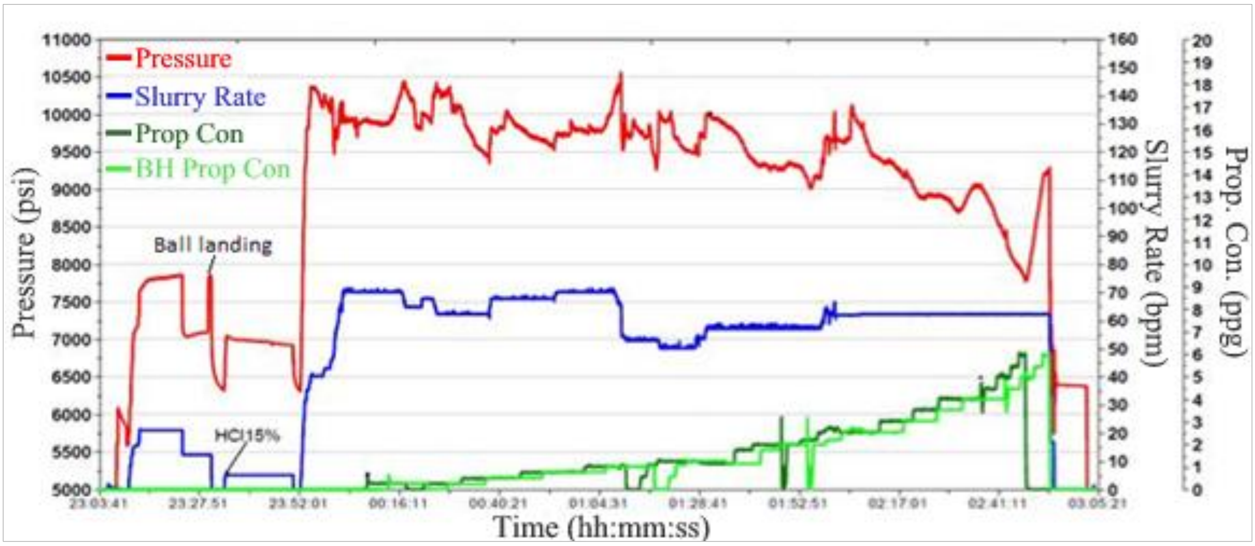

Figure 17. Fracture stage.

Ball Landing

Figure 18 displays the comparison between theoretical and actual volumes pumped to land the ball. With this analysis, it is possible to optimize the ball landing time, enabling better foresight and time to decrease the pump rate and observe the ball landing. The ball typically lands 10 to 20 bbl (1.59 to 3.18 m^3) in advance of theoretical volumes.

Ball landing on stage 14 was not witnessed; however, isolation was checked by comparing pressures with previous stage.

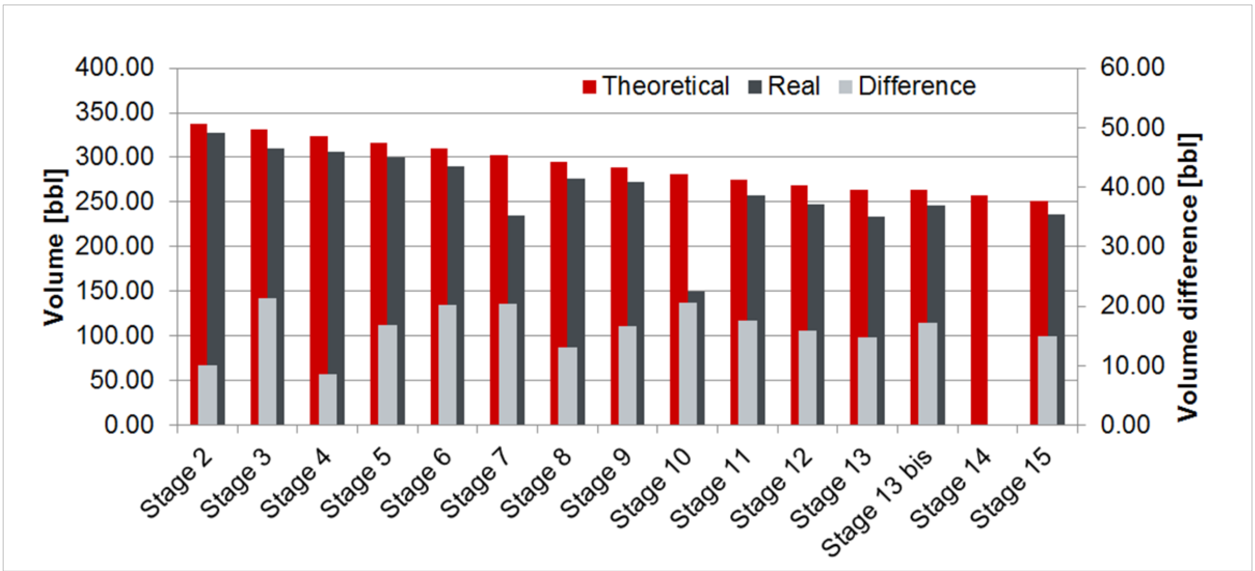

Figure 18. Ball pumpdown analysis.

Plug and Ball Exposure Time

Figure 19 shows the time each plug was exposed to well fluid. Time begins when the wireline BHA is inside the lubricator, and it is filled with fluid to perform the pressure test. The exposure time is completed at the end of the fracture job for that particular stage.

The maximum exposure time was observed on stage 14, which served to confirm ball/DFP durability when exposed to wellbore fluids during a total of 11 hours and 20 minutes, including the stage stimulation time.

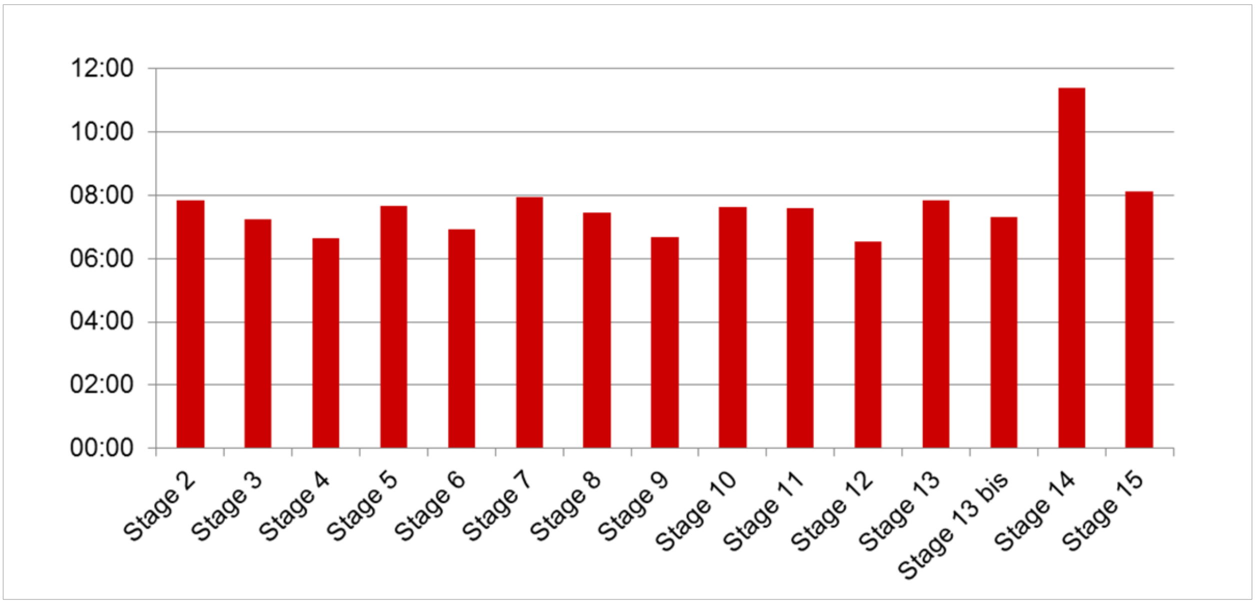

Figure 19. Plug exposure time (Hs).

Figure 20 exhibits the amount of time the plug held pressure on each stage; this represents the time between the landing of the ball on the plug and the ending of the fracture job. In some stages, a four-hour time period was exceeded with no issues.

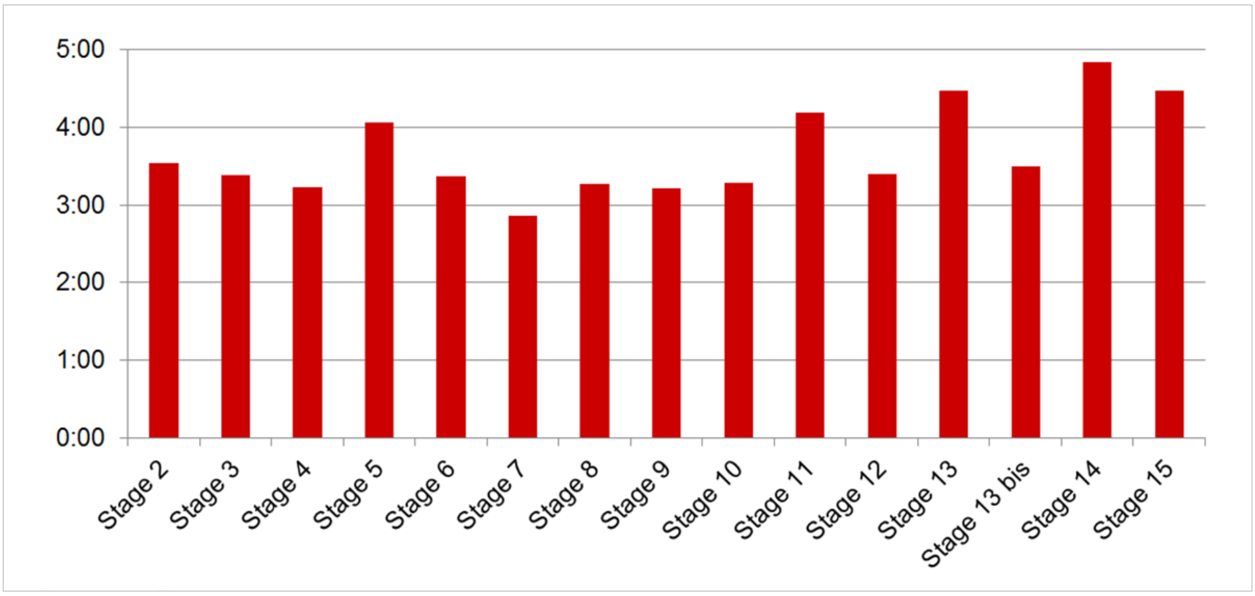

Figure 20. Time the plug holds differential pressure (Hs).

Ball exposure time begins when the ball comes into contact with the well fluid and ends when the fracture job ends. Figure 21 summarizes the ball exposure times for all stages.

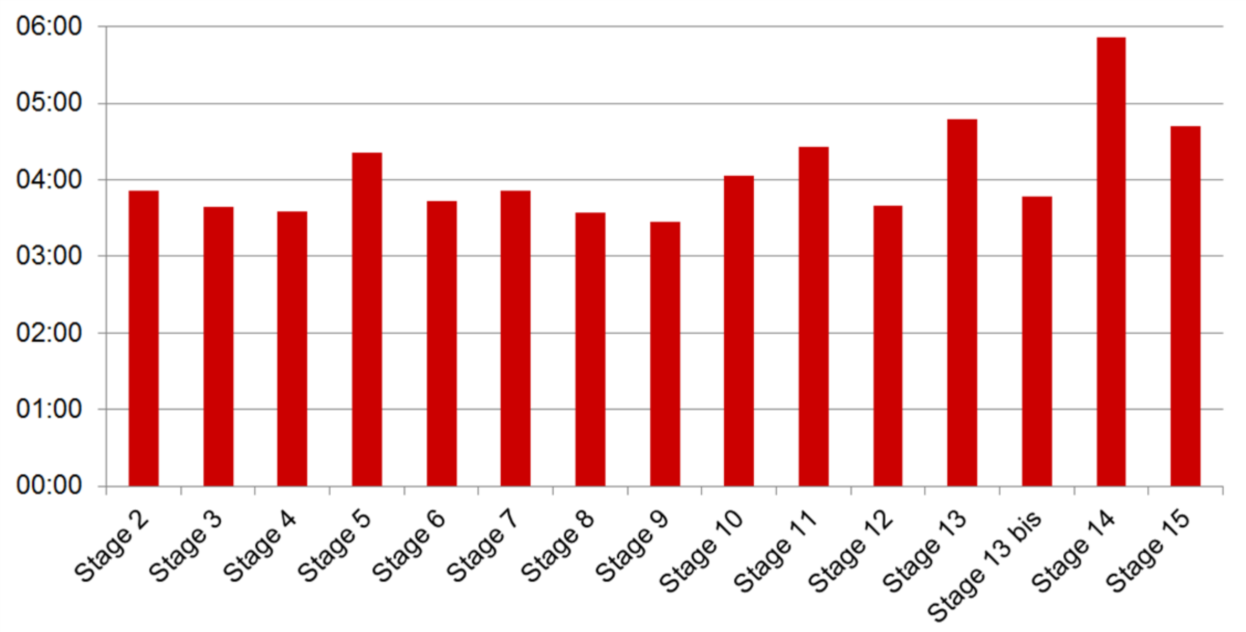

Figure 21. Ball exposure time.

Flowback at Stage 7

A flowback was performed on stage 7 after experiencing a screen out event just when the downhole sand concentration in the frac slurry was at planned maximum. Pieces of DPF were recovered at surface during this operation.

Figures 23 through 25 provide evidence that the technology dissolved as designed, and even more after considering that no chlorides were present in the pumped fluid. The piece shown in Figure 24 has an easily identifiable shape that suggests it was one of the DFP bottom slips. Bottom slips are expected to be one of the last pieces to dissolve because the DFP dissolves from the inside out and end to end. Flow through the DFP internal diameter (ID) removes passivation layers, exposing fresh metal surface, thus increasing the galvanic corrosion speed.

Figures 23 and 24 illustrate the size of the pieces recovered. These pieces are suspected to be part of the first DFP, set in the well approximately four days before the flowback, superseding the dissolution expectation in low salinity fluid.

Figure 22. Pieces of a DFP recovered after flowback during stimulation of Stage 7.

Figure 23. Pieces of a DFP recovered after flowback during stimulation of Stage 7.

Figure 24. Piece of DFP recovered after flowback during stimulation of Stage 7.

Testing

Figure 25 shows measured parameters of well testing, which began 13 days after well stimulation. The salinity increased suddenly from 10,000 to 70,000 ppm. At the time that salinity level reached 70,000 ppm, an approximate volume of 53 m^3 was recovered indicating that the wellbore, with a capacity of 54 m^3, was filled with 10,000 ppm of chlorides.

In addition to the volume of the low salinity fluid recovered, it is important to note that a total of 30.000 m^3 were pumped during the PnP operation. This suggests the chlorides diffused from the formation to the wellbore quickly enough to contact the DFPs within a matter of days. Dissolution speed could be improved by performing a flowback after PnP, which enables the plugs to quickly make contact with high salinity fluids.

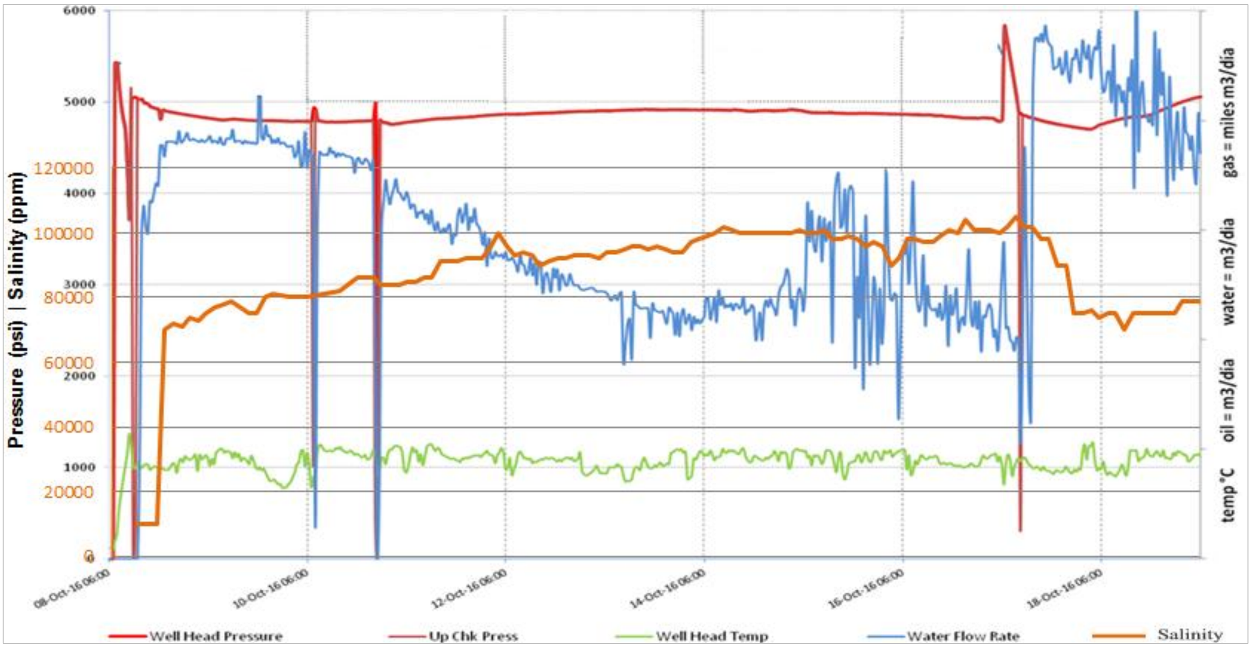

Figure 25. Well testing.

Choke Orifice Plugged

On the first day of well testing, the choke orifice became plugged with debris. It is important to note that the pieces shown in Figure 26 are from steel material and look different from the DFP pieces shown in Figures 23 through 25; the difference in appearance and material proves that the pieces did not come from the DFPs.

Figure 26. Pieces of metal plugging the choke.

Previous experience shows that various types of debris are involuntarily introduced into the well during PnP operations. As shown in Figure 27, rocks, wire, and twisted steel have been found in the sand. Figure 28 shows a choke orifice plugged with nylon from sand bags, and Figure 29 shows a choke orifice plugged with a sticker from a perforation gun.

Because CT operation is not required when using DFPs, no wellbore cleaning is performed before producing the well, and debris inside the wellbore should be avoided.

Figure 27. Example of debris collected from sand used for stimulation operations.

Figure 28. Examples of a piece of rope, presumably from a sand sack, plugging the choking orifice at surface.

Figure 29. Example of a sticker from a perforating gun found plugging the choking orifice at surface.

Conclusions

- DFPs technology provided similar performance to that of traditional composite frac plugs in the RIH operation in terms of running speed.
- DFPs and dissolvable frac balls were able to withstand wellbore/treatment conditions during the experienced exposure times (up to 11 hours and 20 minutes).
- The flow back performed as post-sand out recovery operation provided evidence that the DFPs were dissolving as expected, inclusive in fresh water.
- Considerable cost and time reductions can be obtained from the implementation of the DFP technology in Vaca Muerta shale stimulation operations.
- Eliminating the post-stimulation intervention to drill/mill out plugs also eliminates the risk of trapped tubular as a consequence of tectonic shifting while stimulating nearby wells. In addition, the need to stop stimulation operation in nearby wells is removed, reducing time to production and stimulation crew standby cost.
- Flowing back the well immediately after completing all stimulations stages provides the opportunity to reduce dissolution time by bringing high salinity fluid into contact with the DFP more quickly than performed in this introductory operation.
- The implementation of the DFPs requires more attention to the possibility of debris being introduced in the wellbore. Perforating gun stickers, wire, steel pieces, sand bags, and foreign objects in general should be avoided whenever possible.
- This initial experience served to confirm that the DFP technology does not introduce any limitation to regular PnP operations; on the contrary, it fosters efficiency of PnP operations by eliminating cost and risk while reducing operational expenditure.
- The mathematic model used to calculate displacement volume/time to land the frac ball must be reviewed and adjusted based on actual values obtained from field experience.

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Author Biographies

Esteban Ariel Pach

EDUCATION

Universidad Nacional del Comahue; Neuquen, Argentina
Mechanical Engineer, April 2009

EMPLOYMENT

EDERSA — Febraury 2003 – September 2003
Internship in measurement laboratory

GMF-LPM — October 2006 – January 2007
Internship in Fracture Mechanic Laboratory

INVAP Ingeniería S.A. — November 2007 – September 2010
Mechanical Engineer

Universidad Nacional de Río Negro (UNRN) — March 2010 – September 2010
Teacher in “Tecnicatura superior en mantenimiento industrial”, Subjects:

YPF S.A. — October 2010 – June 2012
Company Man - Completion Engineer

Halliburton — July 2012 - Present
Principal Technical Professional – Completion tools

Russell Dwight Wittig

EDUCATION

Texas A&M University; College Station, TX
Bachelor of Business Administration in Finance and Accounting — Dec 2006

EMPLOYMENT

Halliburton Energy Services

Country Manager Completion Tools & Testing Buenos Aires, Argentina Nov. 2015 - Present

Area Operations Manager Completion Tools Houston, TX Sept. 2014 – Nov. 2015

District PSL Manager Completion Tools Alice/San Antonio, TX Oct. 2011 – Sep. 2014

Service Coordinator Completion Tools Fresno, TX Mar. 2010 –Oct. 2011

Service Specialist Completion Tools Kilgore, TX Jun. 2008- Mar. 2010

Business Development Field Sales Associate Alice, TX Jan. 2007- Jun. 2008

Martin Fernández Costagliola

EDUCATION

Mechanical Engineer (Automotive Specialization)

2007 – 2012. I.T.B.A. (Instituto Tecnológico de Buenos Aires)

EMPLOYMENT

09/2013 – Present. Halliburton Energy Services

10/2012 – 08/2013. Tenaris Siderca

Actual job title

Account Representative Halliburton Completion Tools

Yván Simmons

EDUCATION

BS in mechanical engineer from the Universidad de Carabobo in Venezuela

EMPLOYMENT

2003-Present Halliburton Energy Services

Completions field engineer. Additional local and regional roles in sales, technical and operational support for a variety of different technologies such as Swell Technology, Expandable Liner Hanger Systems, Service Tools, Subsurface Flow Controls and Safety Valves, Wellbore Cleaning Tools and Frac Sleeve Systems. Management roles in Drill-Stem Testing and Sand Control Projects in Latin America Region.

Actual job title

Global Product Champion for Unconventional Completions with primary focus on Frac Sleeve Systems.