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FRAC-PACK WELL STIMULATION

1. INTRODUCTION

Conventional gravel pack was the most frequently applied sand control method for a long period of time during the second half of the last century. This efficient technique is based on viscous fluid (gel) usage transporting and accommodating proppant inside the perforations and casing-screen annulus.

However, viscosified gel application can cause formation damage, thus decreasing permeability in near-wellbore zone. Therefore, a new improved gravel pack methods have been applied which incorporate inhibited water and high pumping rates of fluid (Water Pack and High Rate Water Pack) [1].

Frac-Pack is a relatively new method which encompasses conventional gravel pack and hydraulic fracturing as all-in-one procedure creating fractures and packing them with proppant. It has become the most beneficial and reliable technique for oil or gas well stimulation. It's implementation is possible in both layered and high permeability reservoirs.

On a world basis, the number of Frac-Pack jobs done is constantly increasing. For the past 10–15 years, Frac-Pack well stimulation method application frequency has increased from 100 to thousands of jobs yearly [2].

Hydraulic fracturing and Gravel pack are well known and used techniques for the past 40–50 years, but unified method involving these two just recently (15–25 years ago) became an almost standard well stimulation solution comprising Tip-Screenout (TSO) fracturing that has unique advantages.

During the wellbore drilling, casing cementing, well completion or sand control, formation damage can be a major problem due to service fluids impact which affects the well production. Formation fracturing appearance and sand influx are inevitable when applying improper proppant placement and compaction in the casing-screen annulus or perforations.

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Implementation of Frac-Pack method decreases formation pressure loss tendency caused by formation damage (i.e. skin factor), thus permeability of near-wellbore zone.

When comparing to conventional Gravel pack method, when applying Frac-Pack method, skin factor significantly decreases over the time of production, therefore a much higher production index is observed [2, 3, 4].

2. TSO (TIP-SCREENOUT) PROCEDURE

A key success to good well stimulation is wide and permeable fracture creation. It is done by detaching the wellbore wall from casing and creating a concentric micro annulus between the wellbore and cement, which is also called *'Halo effect',* shown in Figure 1.

Micro-annulus area compaction with proppant provides for efficient hydraulic connection between fracture and perforations, and thereby decreases pressure loss in the zone. As said, fracture done by TSO procedure are quite short and thick allowing for better proppant packing and creation of stronger sand filtration zone between the screen and reservoir.

Highly conductive fracture bypasses the damaged near-wellbore zone ensuring fluid flow without interruption.

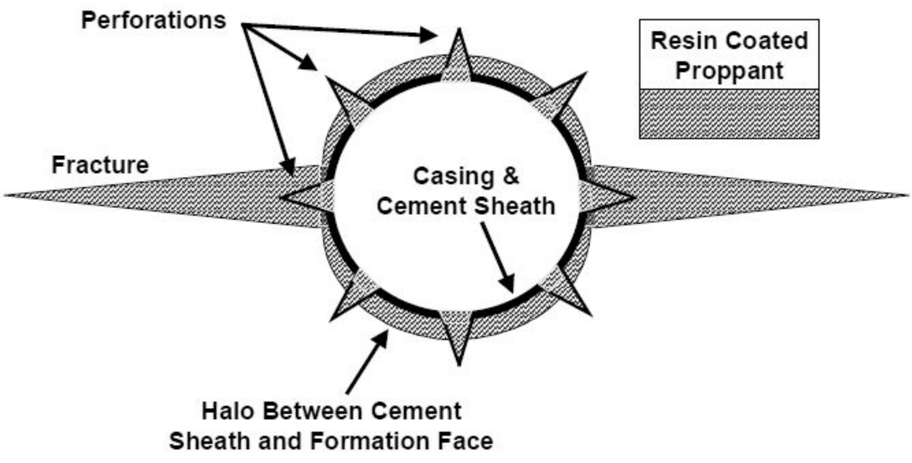

Fig. 1. "Halo" effect [5]

As shown in Figure 2, fractures made in highly permeable formations are wider and shorter, depending on whether the fracturing fluid will be water or more viscous one. Adversely, in low permeability formations longer and narrower fractures are made.

Less viscous fracturing fluids, like water, infiltrate through formation much faster, so a smaller fracture will create. According to Figure 2, between the formation and wellbore bilinear flow is established and thus enhancing effective wellbore radius (r_w) [2, 5].

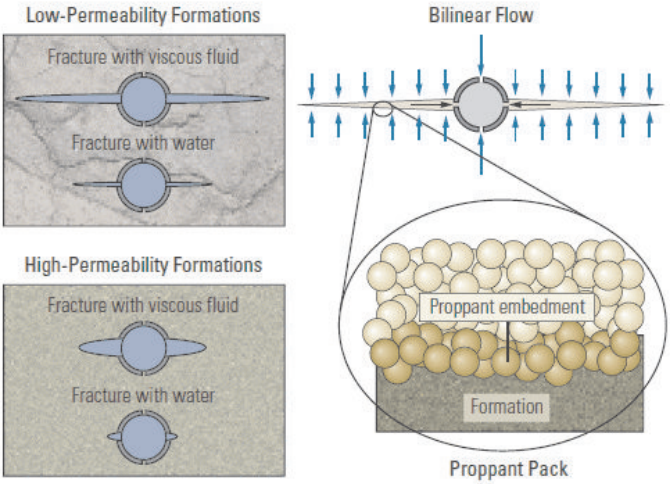

Fig. 2. Fracture length an d profile in high-permeable and low-permeable formations (*left*). Billinear flow established in fracture-formation zone (*right*) [2]

Ideal candidates for this type of fracture creation are:

1. Wells which emphasize need for certain fracture profile creation or simply formation damage bridging in near-wellbore zone,
2. Wells not suitable for acidizing operations,
3. Medium to high permeability reservoirs, with or without near-wellbore zone formation damage,
4. Wells having problem with sand influx,
5. Wells treated with gravel pack method having problem with low HC production due to partial packed zone obstruction by formation sand.

3. FRACTURING FLUIDS

An appropriate fracturing fluid selection has a key role in Frac-Pack well stimulation design. To do it so, fracturing fluid infiltration, fracture permeability, near-wellbore zone formation damage and proppant transportation efficiency have to be considered.

In order to obtain valuable frac fluid properties, interaction and behavior data, distinct lab analysis have to be considered. They include fluid properties (considering infiltration), formation damage intensity, fracture permeability, etc.

There are more then 50 different types of fracturing fluids available on the market today. Three basic types are as follows [4]:

1. Linear gels,
2. Cross-linked gels,
3. Viscoelastic surfactants (VES).

All of the mentioned fluid types can be used in two-phase (gas-liquid) systems.

3.1. Linear Gels

A number of hydraulic fracturing operations is done by water based linear gels. Typical polymers used in these systems are *Guar gum, Guar gum derivatives* (HPG– Hydroxy-propyl guar, CMHPG– Carboxy-methyl hydroxy-propyl guar) and HEC (Hydroxy-ethyl cellulose.

They are all biodegradable.

Guar gum, as a polymer substance produced from guar plant, is non-toxic matter usually added to food to increase its viscosity and elasticity. Figure 3 shows different textures of guar gum used in industry.

For viscous fracturing fluid preparation, guar powder is added and dissolved in it. High fluid viscosity improves proppant transport ability, and, ultimately, it is accomplished with additional viscosifiers added into the system.

For the past ten years, guar gum usage is considerably lessened, being a substance which disintegrates the fracture structure if added in large amounts [2, 4].

a) b)

Fig. 3. Guar gum textures (a and b) [6, 7]

3.2. Cross-Linked Gels

Evolution of cross-linked gels is one of most important improvements in fracturing technology. When these metal gels are added to linear gels, resulting fluid turns out to be having better rheological properties, especially high viscosity, which is maintained until the breaker additives are added.

Hydraulic fracturing operations efficiency can be improved significantly when using the latter and it justifies it's relatively high market price.

However, cross-linked gels appliance bears and deals with another important issue, which is permeability reduction of the packed zone between the screen and wellbore wall. It results from gel dehydration inside the packed zone. Abovementioned problem can be solved by adding a certain amount of breakers or simply increasing the proppant concentration in the slurry [4, 8].

The most important cross-linked gels to mention are:

Borate cross-linked gels

Very efficient and cheap gels capable of dealing with high temperatures.

Polymer-organic gels with metal cations

The most popular cross-linked gels in fracturing technologies. Titanium and zirconium fluids with guar, HPG, CMHPG and CMHEC (Carboxy-methyl hydroxy-ethyl cellulose) base are used. They are also capable of withstanding high temperatures up to almost 160 ^{o}C [9].

Metal cations make the chemical bonding very effective, creating resilient filter cake on a fracture wall.

Foams

Contain a great portion of gas phase. As gas is compressible, foam's rheological properties directly depend on current temperature and pressure.

3.3. Viscoelastic surfactants

Viscoelastic surfactants are viscous water based fluids without addition of polymers. Their wide range of exploitation in drilling, fracturing, gravel packing or similar jobs as gelling agents, has upgraded the stability of fluid systems used.

Its utilization delivers highly permeable fractures, contributing to higher hydrocarbon production rate of the well in the end. As shown in Figure 4, notable difference between fractures made with polymer and VE surfactant fluids is fracture profile (i.e. height, length). Basically, in case of VE surfactant fluid, it follows the pay-zone interface [10, 11].

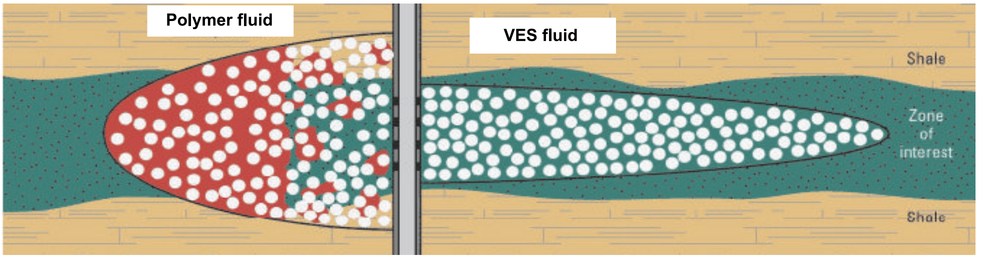

Fig. 4. Cross section of fracture initiated by polymer fracturing fluid (left side) and VE surfactant fracturing fluid (right side) [11]

Most important advantages of viscoelastic surfactant fluids over regular polymer ones are:

1. Much less formation damage done,
2. Easier to mix and prepare for the job execution,
3. Biodegradability,

4. Cross-linking additives not necessary,
5. Near-wellbore zone washing after the operation more efficiently executable,
6. Minor fluid infiltration to formation [12].

4. PROPPANT

Proper proppant selection is very important when designing a Gravel pack/Frac-pack well stimulation in weak formations not very well consolidated. Since a complete sand control objective is to prevent all formation sand penetrating the packed annulus between the screen and formation, all formation sand must be stopped at the interface formation/packed zone.

This may require different sizes of proppant taking into consideration a conductivity decrease tendency with grain diameter decrease.

So, the formation solids control is achieved much more efficiently when there is a packed annulus as a barrier which allows for smooth flow of formation fluids [9].

According to API recommended specifications RP 56 [13], Table 1 presents the list of standard proppant sizes available for Gravel pack or Frac-Pack operations.

Table 1

Standard proppant sizes [13]

Proppant sizes		
Mesh	Sieve opening sizes (mm)	Sieve opening sizes (in)
70/140	0.212 / 0.106	0.008 / 0.004
40/70	0.425 / 0.212	0.017 / 0.008
30/50	0.600 / 0.300	0.024 / 0.012
20/40	0.850 / 0.425	0.033 / 0.017
16/30	1.180 / 0.600	0.046 / 0.024
12/20	1.700 / 0.850	0.067 / 0.033
8/16	2.360 / 1.180	0.093 / 0.046
6/12	3.350 / 1.700	0.132 / 0.067

To achieve effective sand control, design considerations must contain productive layer depth, fluids production rate, downhole pressure, critical fluid flow velocity, geomechanical productive layer properties and, last but not least, proper produced sand size determination.

Types of proppant used in Frac-Pack operations are as follows:

Natural quartz sand	*Manmade artificial proppants*
– Ottawa sand	– Ceramic beads
– Brady sand	– Sintered Bauxite
– Ticino sand	– Resin-coated proppant [4]
– Resin-coated sand	

4.1. Resin-coated sand

This type of sand, when used, achieves excellent sand control ability. Grains can be *curable* or *pre-cured* with resin. Unlike the pre-cured, curable ones are cured after the treatment when the well shuts in. Sticky resin (crosslinked polymer) layer coats the sand grains.

After the sand spotting job is done, due to high temperature values downhole, resin dissolves and consolidates grains procreating stable packed boundary leaving the formation sand behind it. Stability and permeability of packed zone done with resin-coated sand depends on resin polymer properties, so the formation temperature awareness and polymer physical and mechanical properties are crucial for job success.

Generally speaking, there are two main types of resin used: **Epoxy** and **Phenol resin**.

Epoxy resin comprises of active component (epoxide) and polymer crosslinking substance. Phenol resin comprises of active component and Hexamethylen tetramine crosslinker.

If a wrong laboratory testing on resin polymer is done, formation temperature can plasticize the resin or make the polymer bonds unstable. In these cases, absence of good end results would be obvious.

Resin-coated sand/proppant implementation prevents sand influx at extremely high fracture closing pressures and it's embedding into formation is reduced to minimum. Figure 5 shows the particles interaction in case of resin-coated sand and a regular one. On resin-coated particles stress is allocated over a greater area so a greater breaking resistance of particles is achieved [14, 15].

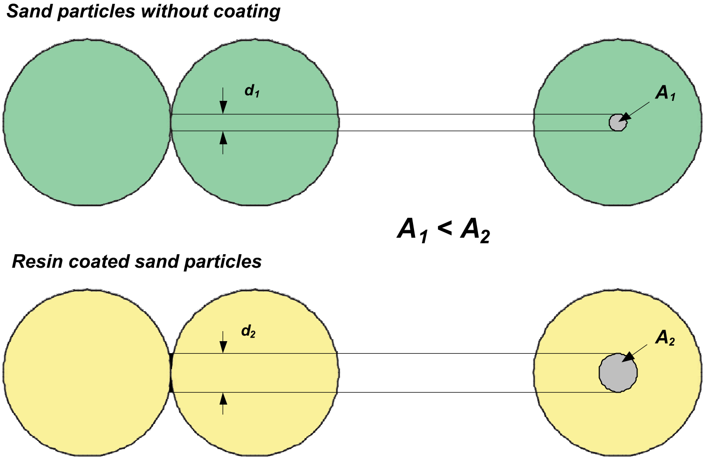

Fig. 5. Contact area between two particles in case of resin-coated sand and the one without coating [16]

5. WELL COMPLETION AND JOB EXECUTION

Like conventional gravel packing, fluids and proppant for Frac-Packing are injected through tubing and a gravel pack packer with 'Service tool' (see Fig. 6a). However, to withstand high pressures during Tip-Screenout fracturing, standard Gravel pack assemblies should be adapted to it. Modifications should include increased metal hardness, larger cross-sectional areas and minimizing sudden changes in flow direction to reduce metal erosion by fluids and proppant.

Friction pressures generated by pumping slurry through tubing and completion equipment often mask true downhole pressure responses when monitoring treating pressure at the tubing surface. As a part of downhole equipment, ball valve allows for pressure changes to be monitored in real-time during treatments when the ball valve is opened (Fig. 6b).

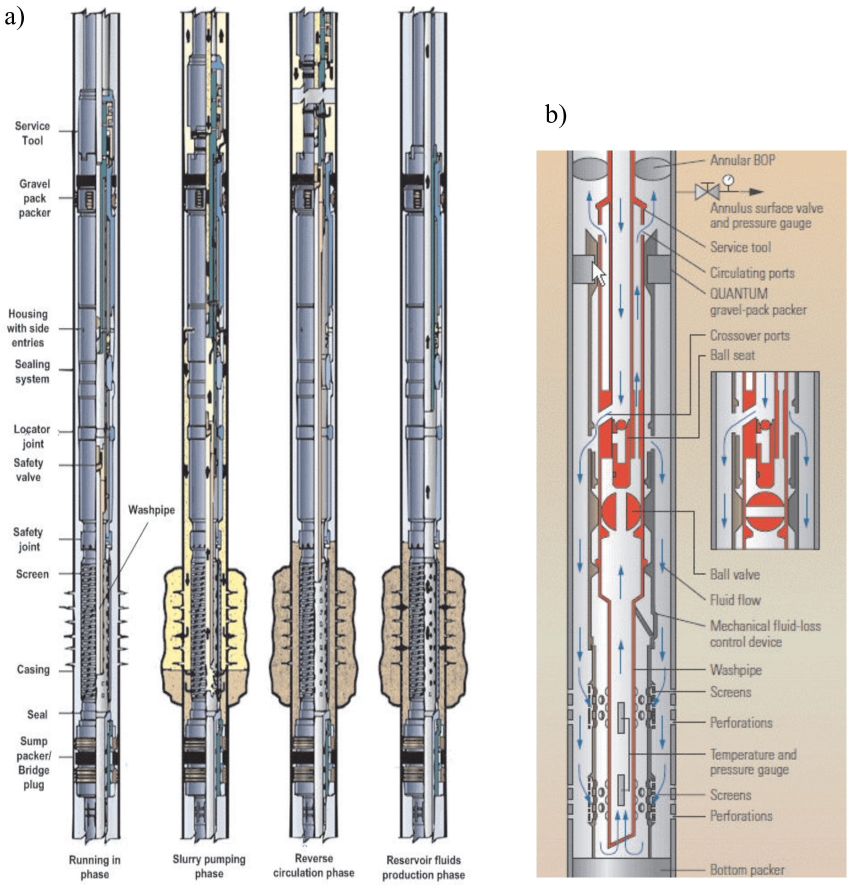

Fig. 6. Frac-pack operational procedure and tools involved [2, 17]

Frac-Packing usually begins in squeeze configuration. After Tip-Screenout occurs, establishing circulating configuration ensures complete packing of the screen and proppant grains contact. Service Tool is then shifted to clean out excess slurry by pumping fluid down the annulus and up the tubing. The amount of upward movement required to shift service tool pulls reservoir fluids into wellbore. This swabbing effect can bring formation sand into perforation tunnels before a fracture is completely packed or reduce conductivity between fractures and the packed area.

Second phase of the process includes ball valve closing and shifting the tool configuration with upward movement. Service Tool and the Washpipe detaches from the assembly and pulls out of the well (Fig. 6).

In addition to variety of reservoir conditions and of fracturing and gravel packing requirements, treatment execution must address the complexity of completing multiple zones and long intervals. Even the best Frac-pack designs end in failure if excess fluid loss into formation causes proppant bridges to form in screen-casing annulus, restricting or blocking annular flow. Annular proppant packoff or bridging results in early treatment termination, low fracture conductivity and an incomplete gravel pack around screen.

Some screens use hollow rectangular tubes, called *Shunt tubes*, welded on the outside of screen body to provide additional flow path for the slurry. Shunt tubes provide transit paths for slurry to bypass collapsed hole and external zonal isolation packers as well as annular proppant bridges (Fig. 7 and 8). If annular restrictions form, injection pressure increases and slurry diverts into the shunt tubes, the only available open flow path. It ensures fracture coverage and complete gravel packing around the screen across the entire perforated interval [2, 4].

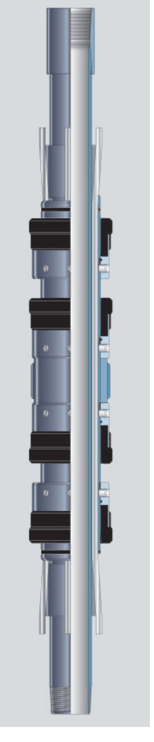

Fig. 7. Gravel pack packer with Shunt tubes [17]

a)

b)

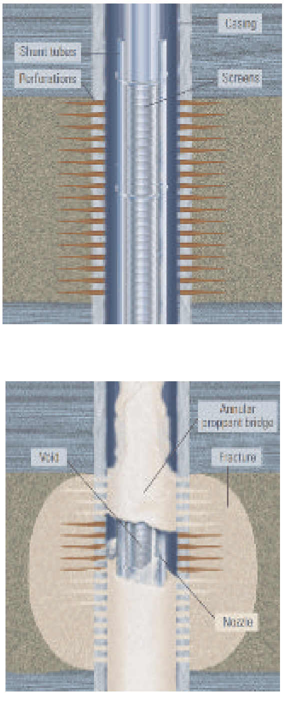

Fig. 8. Screen with Shunt tubes (a). Annulus proppant bridging while pumping slurry (b) [2]

6. FRAC-PACK OPERATION CASE STUDY-OFFSHORE CROATIA

In one of the gas fields in the central part of Adriatic Sea in Croatia (*Field-1*), a number of wells have been drilled and *Well-N* is one of them. From the existing wellbore Well-N, three directional wells were drilled: *Well A dir*, *Well B dir* and *Well C dir*.

In Well B dir, two sand control operations were carried out, each one on separate production pay zones (*pay zones α and β*). On pay zone α, a gravel pack operation was performed, with water based fluid as a carrier. On pay zone β a Frac-Pack operation was performed.

Detailed overview of sand control operations performed on Well-N well is shown in Figure 9.

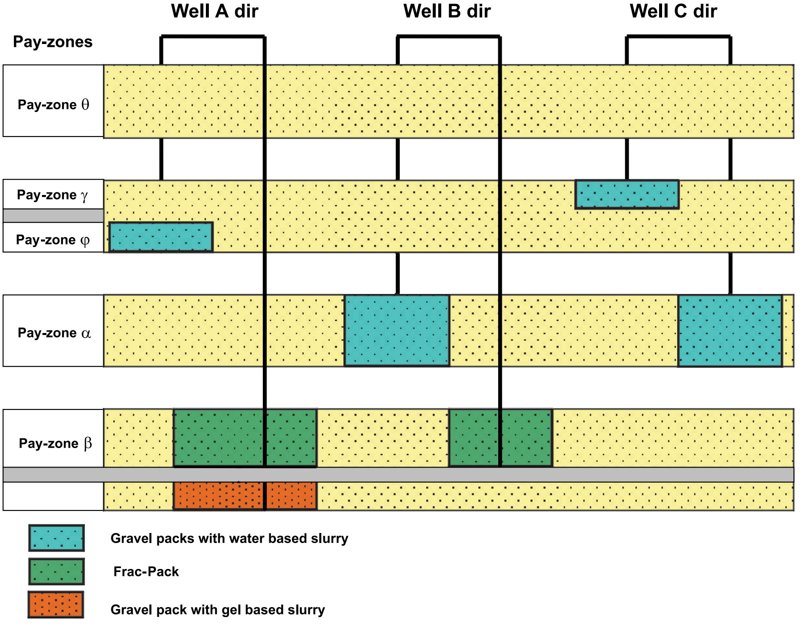

Fig. 9. Sand control operations overview executed in Well-N well [18]

After the Well B dir re-entry 8 ½" drilling phase, 7" casing was run and cemented. Cement bond log (CBL) took place and proved it was a good cementing job. Perforating guns were run afterwards and 1359 – 1364,5 m interval of pay zone β was perforated. A sump packer was run and set at 1372,6 m. Right after the sump packer, gravel pack packer assembly was run to 1372,6 m and spaced out with gravel pack packer setting depth of 1333,8 m. Friction test was performed in reversed and normal circulation. In normal circulation, three pumping rate values were tested (0,32–0,47–0,63 m^3/min). Related surface pressures recorded were 11–25–42 bar. In reverse circulation testing was performed with (0,32–0,47–0,63–0,80–0,95 m^3/min). Related surface pressures were as follows– 11–21–39–56–77 bar.

After closing the BOP, ‘Step Rate Test’ [18, 19] followed with different pumping rates (0,08–0,16–0,32–0,47–0,63 m^3/min) inducing the following annulus pressures– 20–24–35–42–48 bar. The fracture extension pressure was found to be at 31 bar on the annulus while pumping 0,16 m^3/min.

Minifrac test (injection test) was done with viscous viscoelastic surfactant (VES) water ba-sed polymer free fluid by pumping 0,80 m^3/min. Pressure induced on the annulus was 42 bar.

The Frac-Pack operation itself was performed by pumping 20,28 m^3 of VES water based fluid ladden with 30/50 mesh ceramic beads at 0,80 m^3/min. Maximum concentration of proppant was 6,5 PPA – pounds of proppant added per gallon. Tip-Screenout occurred at 54 bar of annulus pressure. Reverse circulation was performed afterwards to wash out the packed annulus with 2948 kg of sand recovery (3402 kg of sand remained inside the well). There are few interesting data about the operation and tools used in Table 2 and Figure 10 [20].

6.1. Conclusive facts on the job performance

During the Frac-Pack job at 0,8 m^3/min flow rate, thin layers were broken, but the fracture could be still considered contained. When higher proppant concentrations reached the perforations, the net pressure gain was high enough to break through the shaly section. According to logs, fracture initiation direction was upwards.

Pay zone Y was successfully stimulated. Bottomhole flowing pressure increase during the fluids production was more then 20 bar and it is increasing constantly. HC production rate and reservoir communication happened to be much better then before due to proper fracture and formation-casing annulus fill (‘Halo’ effect) with proppant.

7. CONCLUSION

Frac-Pack well stimulation technique is being successfully performed worldwide. By combining hydraulic fracturing and Gravel packing, a unique method is acquired which unifies advantages of the aforementioned techniques. Implementation of this distinguished sand control/well stimulation method accounts for better formation damage bypass and permeability improvement, unlike the skin occurrence with conventional gravel pack method. Quality laboratory data are vital to good Frac-Pack job execution and project management. A proper fracturing fluid and sand/proppant type selection is one of the most important input entries when performing a job design. Bottomhole and surface tools have to be reliable, functional and pre-tested to ensure all safety precautions are met.

So, to conclude, with properly designed and conducted field work, Frac-Pack method is efficient sand control technique that usually pays off all your investments.

Table 2

Operational tools and treatment data [20]

Well data	
Well name	Well B dir
Layer	Pay zone β
Interval length (m)	5.5
Well inclination at perfs. (deg)	54.5^o
Casing size (in)	7
Casing weight (ppf)	23
BHP- Bottom hole pressure (bar)	105.5
BHT- Bottom hole temperature (°C)	38
Reservoir permeability (mD)	200
Reservoir porosity (%)	30
Completion fluid type	$CaCl_2$ brine
Completion fluid weight (kg(m^3)	1040
Operational tools	
Gravel pack packer depth (m)	1333.8
Sump packer depth (m)	1372.6
Screen type	Pre-packed
Screen OD (m)	0.1168
Screen length (m)	15.54
Blank pipe OD (m)	0.1206
Blank pipe length (m)	2.9535
Seal bore extension OD (m)	0.1143
Seal bore extension length (m)	0.8839
Perforation interval MD (m)	1359–1364.5
Perforation interval TVD (m)	1039.4–1048.3
Perforations shot density (spf)	12
Perforating technique	Overbalanced
CBL log (good or bad)	Good
Treatment data	
Fluid type	2,5% water based VES
Proppant type	Ceramic beads
Proppant size (US mesh)	30/50
Max. proppant concentration (kg/m^3 of fluid)	1437
Proppant density (kg/m^3)	2680
Proppant pumped (kg)	6350
Proppant recovered on surface (kg)	2948
Proppant remaining in the well (kg)	3402
Average pumping rate (m^3/min)	0.8
Total slurry volume pumped (m^3)	20.28
Pad volume (m^3)	4.542
TSO occurrence (yes/no)	yes
Losses before Frac-Pack (m^3/h)	0.3
Losses after Frac-Pack (m^3/h)	6.0

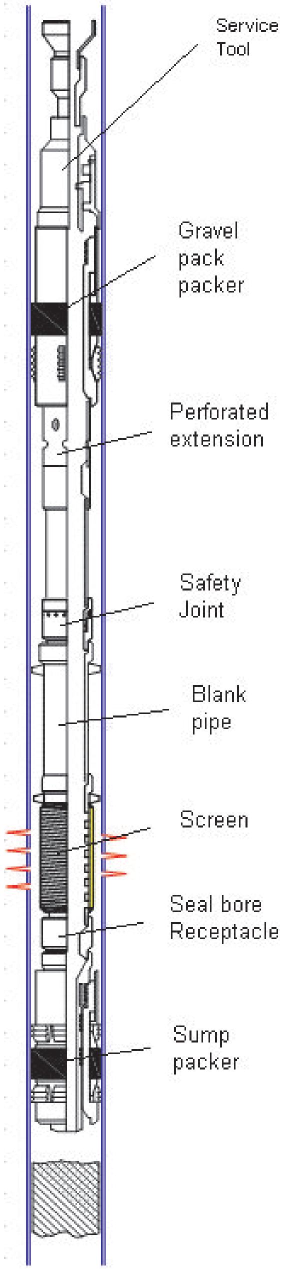

Fig. 10. Gravel pack assembly [20]

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