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Achieving Zonal Isolation with Three-Stage Cementing using multiple Mechanically Activated External Sleeve Inflatable Packer Collars in Washed-out Deviated Hole under Total Losses, Qatar Offshore.

Muhammad Faraz Khan, Zahid Karajagi, Vincent Pradet and Sudish Bhat, North Oil Company; Gaurav Gupta, Priyadarshini Chaudhary, Francois Missiaen and Javier Urdaneta, Halliburton.

Abstract

Achieving zonal isolation around driven conductor shoes in highly deviated surface casing with shallow flow, washouts and total losses is challenging. This typically requires a 3-stage cementing solution for isolation. Historically, the company has had very low success rate with conventional hydraulic stage tools and packers.

Multiple complexities arise in three-stage cementing while operating with hydraulic stage tools and packers viz. 7 pressure triggers, packer burst in large hole size, inability to open stage-tool ports with packer leak, inaccurate pressure estimations with total losses and annulus flooding (back-fill). This leads to potential loss of casing integrity and inability to test casing to desired pressures.

This paper discusses successful applications of Tandem-Run multiple mechanically-activated “Integrated Packer – Stage Collar” tools, with tailored volume-based pressure ramping procedures. The procedures allow for controlled packer inflation and opening of stage-collar ports, independent of hole size and annular losses.

Simple internal valve locking mechanism keeps the packer inflated irrespective of packer-hole sealing, thereby supporting the cement column to provide zonal isolation around the conductor shoe. The ability to seal-off ports with integrated external sleeves post cementing restores casing integrity and keeps the packer bladder isolated. Internal opening seats used to cover packer inflation system provides ability to pressure test the casing after every stage.

With 4 successful case-histories, this paper outlines key considerations for well design, packer setting depths, volume-based pressure ramping schedules and job procedures including guidelines for cementing operations.

Introduction

Al Shaheen (ALS) is one of the world’s largest oil producing carbonate fields, lying 180km North of Doha and is a conventional oil field situated offshore, with a water depth ranging from 185 to 230 ft. Over 500 ERD wells have been drilled across the field in a compact line pattern with approximately 25 platforms across 12 locations.

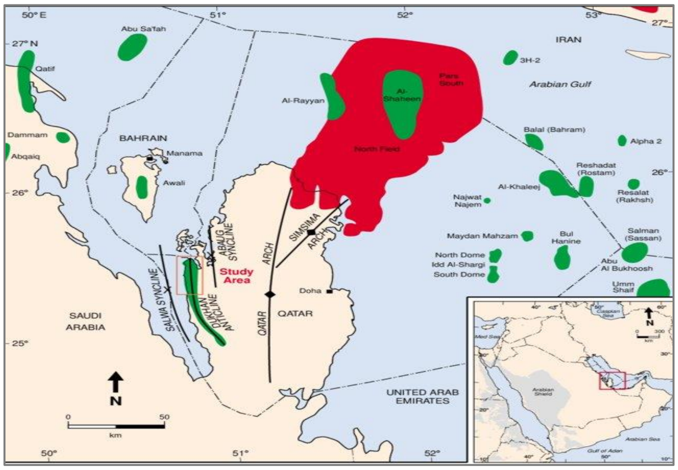


Fig 1: Al Shaheen oil field, Qatar

A typical drilling platform has up to 40 well slots stacked up close to each other (approximately 3ft apart). Some of top-hole sections are drilled and conductor pipe cemented in place.

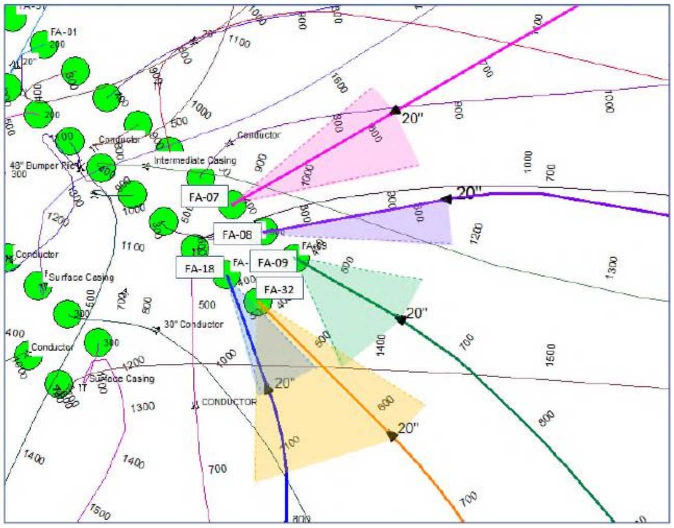


Fig 2: Typical Drilling Platform and Conductor Pipe Orientations

A typical Al Shaheen well has a 20” conductor hammered in the seabed until refusal (600ft to 850ft MD). A 16” surface hole is drilled across H_2S bearing cavernous total loss zones (Rus and UER formations) with no returns until the Laffan Shale formation (2600ft to 3200ft MD, up to 70deg inclination). The well is secured by running a 13-3/8” casing cemented in two stages.

- Stage-1: Cement from shoe to loss zone
- Stage-2: Cement from stage tool to surface inside the casing-casing section.

Consequently, a 12-1/4” section is drilled and completed with a 9-5/8” casing cemented in place up to surface (4,500ft to 8,000ft MDRT). The 8-1/2” reservoir sections are typically long horizontal drains (20,000ft to 35,000ft MDRT) completed either barefoot or with multizone intelligent completions.

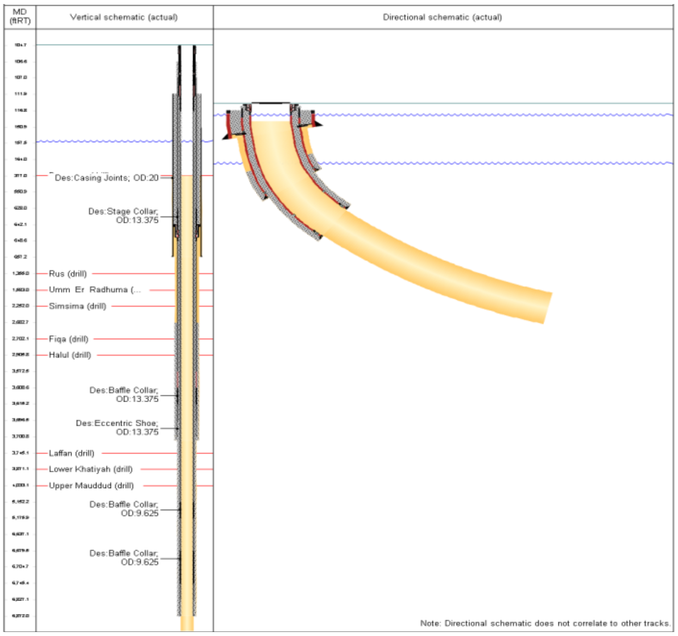
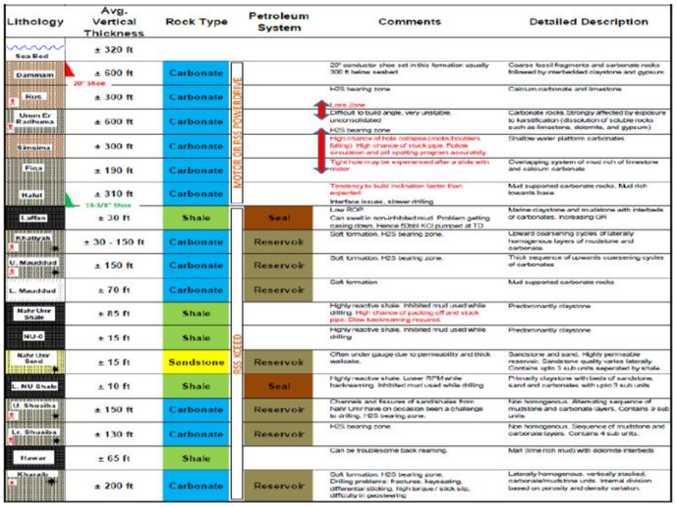


Fig 3: Typical Al Shaheen ERD Well



Lithology	Avg. Vertical Thickness	Rock Type	Petroleum System	Comments	Detailed Description
Sea Bed	± 320 ft				
Dammam	± 600 ft	Carbonate		20" conductor shoe set in this formation usually 300 ft below seabed	Coarse fossil fragments and carbonate rocks followed by interbedded claystone and gypsum
Rus	± 300 ft	Carbonate		H2S bearing zone Loss Zone	Calcium carbonate and limestone
Umm Er Radhuma	± 600 ft	Carbonate		Difficult to build angle, very unstable, unconsolidated H2S bearing zone	Carbonate rocks. Strongly affected by exposure to karstification (dissolution of soluble rocks such as limestone, dolomite, and gypsum)
Simsima	± 300 ft	Carbonate		High chance of hole collapse (rocks/boulders falling). High chance of stuck pipe. Follow circulation and pill spotting program accurately.	Shallow water platform carbonates
Fiqa	± 190 ft	Carbonate		Tight hole may be experienced after a slide with motor	Overlapping system of mud rich of limestone and calcium carbonate
Halul	± 310 ft	Carbonate		Tendency to build inclination faster than expected Interface issues, slower drilling	Mud supported carbonate rocks. Mud rich towards base
Laffan	± 30 ft	Shale	Seal	Low ROP Can swell in non-inhibited mud. Problem getting casing down. Hence 50bbl KCl pumped at TD	Marine claystone and mudstone with interbeds of carbonates. Increasing GR
Khatiyah	± 30 - 150 ft	Carbonate	Reservoir	Soft formation. H2S bearing zone.	Upward coarsening cycles of laterally homogenous layers of mudstone and carbonate.
U. Mauddud	± 150 ft	Carbonate	Reservoir	Soft formation. H2S bearing zone.	Thick sequence of upwards coarsening cycles of carbonates
L. Mauddud	± 70 ft	Carbonate	Reservoir	Soft formation	Mud supported carbonate rocks
Nahr Umr Shale	± 85 ft	Shale		Highly reactive shale. Inhibited mud used while drilling. High chance of packing off and stuck pipe. Slow backreaming required.	Predominantly claystone
NU-0	± 15 ft	Shale		Highly reactive shale. Inhibited mud used while drilling	Predominantly claystone
Nahr Umr Sand	± 15 ft	Sandstone	Reservoir	Often under gauge due to permeability and thick walcake.	Sandstone and sand. Highly permeable reservoir. Sandstone quality varies laterally. Contains upto 3 sub units seperated by shale.
L. NU Shale	± 10 ft	Shale	Seal	Highly reactive shale. Lower RPM while backreaming. Inhibited mud used while drilling	Primarily claystone with beds of sandstone, sand and carbonates with upto 3 sub units
U. Shuaiba	± 150 ft	Carbonate	Reservoir	Channels and fissures of sand/shales from Nahr Umr have on occasion been a challenge to drilling. H2S bearing zone.	Non homogenous. Alternating sequence of mudstone and carbonate layers. Contains 9 sub units.
Lr. Shuaiba	± 130 ft	Carbonate	Reservoir	H2S bearing zone.	Non homogenous. Sequence of mudstone and carbonate layers. Contains 4 sub units.
Hawar	± 65 ft	Shale		Can be troublesome back reaming.	Marl (lime rich mud) with dolomite interbeds
Kharaib	± 200 ft	Carbonate	Reservoir	Soft formation. H2S bearing zone. Drilling problems: fractures, keyseating, differential sticking, high torque / stick slip, difficulty in geosteering	Laterally homogenous, vertically stacked, carbonate/mudstone units. Internal division based on porosity and density variation.

Fig 4: Al Shaheen Field Lithology

Wells constructed close to each other offers significant challenge of achieving proper zonal isolation around the conductor casing.

The success criteria for the cementing of the 13-3/8 casing requires the cement to reach surface and cover three critical zones:

1. At the 13-3/8” shoe: cement must be present and build sufficient compressive strength to allow for drilling ahead with a strong enough Formation Integrity Test.
2. Across the Laffan formation: cement must isolate the water and gas bearing formation, not intended for production. The gas and water flows can disrupt the cement placement by percolation and channeling which may cause premature wear of the casing and fluid migration to surface.

In the casing-to-casing annulus the cement must be bonded between the 20” CP and 13-3/8” casing to ensure that no fluid is reaching the surface.

In special cases, 3-stage cementing is required for 13-3/8” casing to isolate problematic zone(s) below the 20” conductor shoe. The below occurrences are understood to require the 3-stage cementing:

1. **Leak path to seabed**
   A localized leak to seabed and drilling fluid migration to surface has been experienced in some wells during 16” section drilling. This is typically observed by an ROV at seabed indicating a leak path from the 16in section to the seabed.

2. **Very-shallow loss zone near the CP shoe**
   Total losses have been observed in some wells immediately below the CP shoe, especially on platforms with multiple existing CPs in place. This escalates the risk to a leak path to the seabed.

   Under the above two scenarios, the stage tool with the packer is placed below the identified leak path & light weight thixotropic cement is pumped with 400% volume excess to seal the leak path.

3. **20″ CP slippage**
   Risk of 20″ CP slippage has been observed in some cases either due to lost circulation underneath the casing shoe, poor formation stability at casing setting depth or false indication of refusal during hammering, lowering the ability to suspend the CP load.
   In this scenario, the stage tool with packer is placed close by the CP shoe & a high strength 15.8ppg cement is pumped to strengthen the CP shoe.

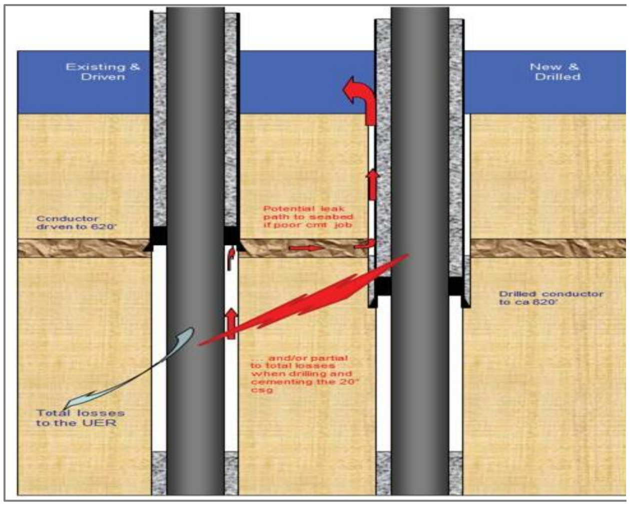


Fig 5: Well Schematic depicting communication between proximity wells

Setting stage tools with packers in the open hole is challenging due to severe washout & total losses.

Background and Challenges

Historically, a 3-stage cement job was performed with one set of stage tool (mechanically operated) coupled with a hydraulic packer placed in open hole between the CP shoe & loss zone (UER), and a second set of mechanical stage tool with hydraulic packer, placed inside the previous 20” CP to bring the cement to surface.

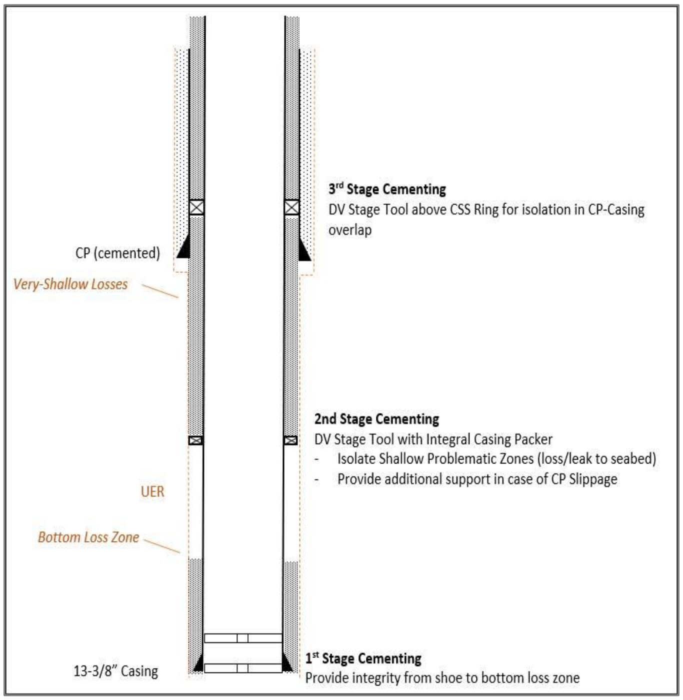


Fig 6: Cemented casings

The use of two inflatable packers and stage tools brings significant complexity to the job (refer to section Historical Stage Tool & Packer Operations-Pressure Triggers)

In addition, the lower stage tool & hydraulic packer is invariably set across the Dammam formation which is prone to heavy washouts (up to 30” diameter). The hole is under total losses while performing stage tool operations.

Setting hydraulic inflatable packers in washed out open holes have seen multiple failures in the past due to excessive inflation causing the packer to rupture and/or diminishing the ability to hold the hydrostatic column.

This uncontrolled packer inflation often led to packer element failure leaving the operator with potential casing integrity issue preventing them from drilling further, and led to temporary abandonment of the well. (Al Mahroos et al., 2023).

Historical Stage Tool & Packer Operations-Pressure Triggers

An inflatable casing packer normally uses pressure triggers to operate the opening & closing mechanism of the packer.

Stage tools also require pressure to be applied to open and close, and these pressure triggers can interfere with the packer inflation system causing premature and partial setting of packers.

The pressure events expected during a 3-stage cement job with packers are listed below in order of their occurrence:

1. Limit the surface pressure after plug bump of the first stage below packer inflation pressure.
2. Pressure-up for opening the lower packer for inflation.
   a. Do not allow the pressure to drop below the packer closing pressure to prevent premature closure.
3. Bleed-off pressure for closing the lower packer and locking the pressure in the packer.
4. Drop the lower stage tool opening device, and pressure-up to opening pressure.
5. Post cement pumping,
   a. Drop the lower tool closing plug and pressure-up to close the lower stage tool.
   b. Limit the closing pressure below the upper hydraulic packer opening pressure.
6. Pressure-up to open and inflate the upper packer.
   a. Do not allow the pressure to drop below the packer closing pressure to prevent premature closure.
7. Bleed-off pressure for closing the upper packer and locking the pressure in the packer.
8. Drop upper stage tool opening device, and pressure-up for opening.

9. Post cement pumping, drop the closing plug and pressure-up for closing the upper stage tool.

While the stage tool sleeves are protected from premature activation as they require a physical plug (opening device) to operate, the hydraulic inflatable packers have no protection to the above pressure triggers applied during the job.

Control of surface pressures with the cement unit at every step of the job operations to avoid premature opening/closing of the hydraulic packer was very challenging. This risk is high during the displacement of the 1st stage cement job since the displacement pressure is dependent upon multiple uncontrolled variables such as hole condition, actual top of cement, quality of cement slurry (density and rheology) pumped on the fly.

Solution Profile:

A two-step approach was adopted to mitigate risk & achieve the objectives of the 3-stage cement job:

- Reducing the number of pressure triggers by introducing the ESIPC™ (Stage Cementer Packer Collar) technology
- Modified Packer Inflation approach for Open Hole

Improving the reliability of packers and stage tools in the 3-stage scenario

Reducing the number of pressure triggers

The first main challenge to address in 3-stage cementing is to reduce or even eliminates the number of pressure triggers for the packers and stage tools.

This was achieved by replacing the stage tool & hydraulic packer set by an ESIPC (Stage Cementer Packer Collar) one in open hole & one in cased hole.

The Type P ESIPC (Stage Cementer Packer Collar) is a combination of a Type P ES stage tool with an integral inflatable packer element. Type P ESIPCs (Stage Cementer Packer Collar) are available with either 3 or 10 ft long elastomer packer elements in casing sizes of 4-½” and larger.

The Type P ESIPC (Stage Cementer Packer Collar) can be set inside casing or open hole to support the hydrostatic weight of annular well fluids above the inflated packer.

The Type P ESIPC (Stage Cementer Packer Collar) operates mechanically to allow inflation of the packer element and to permit circulation above the packer element after complete inflation. Opening is made possible by seating an opening plug into the opening seat of the tool and applying casing pressure. The tool is closed in a similar manner by seating a closing plug into the closing seat of the tool and applying casing pressure.

First, a sleeve mechanism protecting the inflation mechanism until it needs to be activated allows for the tools to be operated independently of each other. Then a closing mechanism common to both the stage tool and packer provides an additional seal to the packer and ensures it is sealed at the right time of the operation.

Integral Packer and Stage Cementing tools have been used in various projects for many years in cased and open holes. The system already has proven track records in the Middle East for similar 2-stage application. (Borges et al., 1993).

The typical tool system is composed of an inflatable packer connected directly to the stage tool with a coupling and an over-coupling with a flow path to allow for inflation fluids to travel from the stage tool opening sleeve to the packer. Figure 7 below displays an example of such system.

The opening sleeve of the stage tool prior to operation is shutting off the flow-path to the packer, allowing for any pressure to be applied to the entire casing string during the cement job without the risk of prematurely inflating the packer. The opening sleeve is typically operated by launching a free fall opening plug (figure 8) and by applying low pressures on the cone once seated (around 300 to 500 psi depending on tool design and size).

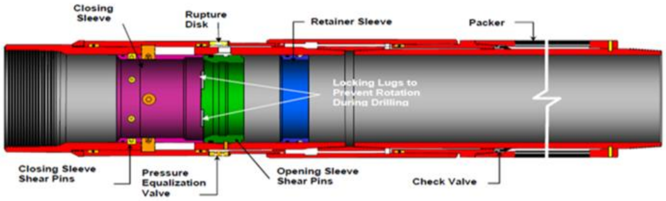


Figure 7: Representation of an External Sleeve Stage Collar with integral packer.

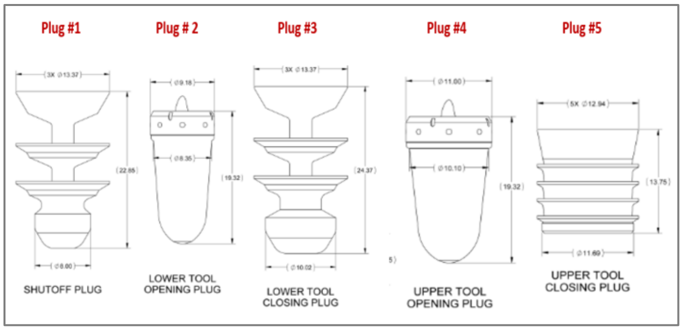


Figure 8: Typical plug set for operating integral packer and stage collar.

The flow is directed towards the packer, while the stage tool is maintained closed by a set of rupture discs set to the desired inflation pressure of the packer. This allows for the packer to inflate with the necessary volume of fluids and pressure for the casing. Once the designed inflation pressure is reached the stage tool rupture discs are burst and a flow path is opened to the annulus for performing the second stage cement. At the end of the cement job, the tool is closed using a top plug with a special

nose, which will pull the external sleeve into a locked position, covering the stage tool ports with a set of seals, thereby also shutting of the flow path to the packer.
During the packer inflation process, a check valve (figure 9) inside the tool mandrel allows for liquid to be pumped to the packer preventing it to return back to the casing, so that the packer maintains its inflation pressure throughout the job.

Conventional stand-alone inflation packers, however, use a set of opening and closing valves to operate. The opening valve is typically exposed to the pressure inside the casing from the time of installation until the end of the job. When the pressure applied inside the casing exceeds the threshold for the opening valve to actuate, a flow path to the packer is open allowing for slow transfer of fluid from the annulus to the inside of the packer. Once the pressure inside the packer reaches the closing valve actuation pressure, the closing valve shuts-off closing the inflation path to the packer. The full system is finally sealed by bleeding off the applied pressure inside the casing, which will make the opening valve close , usually with a mechanism to prevent it from re-actuation.

Such systems comes with several advantages and drawbacks. Advantages include:

- Controlled low flow inflation of the packer, allowing for uniform inflation.
- Single use system – the packer cannot be re-opened after use to prevent its over-inflation and subsequent failure.

However, the drawbacks of such system include:

- Risk of premature opening of the packer if the casing pressure is overshot during cement displacement (pack-off, small annulus, ECD) or casing test (post plug bump).
- Possibility to create a soft set if the pressure inside the casing is lost before the packer can be fully inflated – the single use opening valve would prevent re-opening of the packer while not enough pressure is trapped to enable a strong seal for the second or third stage.
- The need to adjust the pinning of the packer by replacing shear wire on the valve block, which can cause control quality issues on the preparation of the packer.

The use of Integral Packer and Stage Collar tools eliminates the risk of pressure trigger interferences for the packers as well as the risk of premature inflation and opening. Integral Packer and Stage Collars also eliminate the risk of soft set, as if the pressure is lost in the casing during inflation. The inflation sequence can be restarted thanks to the proprietary check valve inside the tool. The packer is only definitely shut upon closure of the stage tool sleeve at the end of the cement job.

One major advantage of this Packer closing system and Stage Collar assembly is the ability to maintain a seal between the casing, the packer chamber and the annulus, in case of packer failure by rupture.

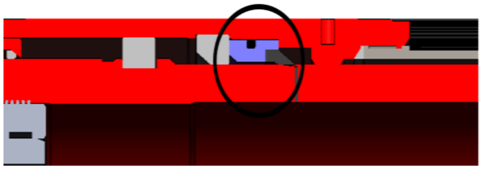


Figure 9: non-return check valve protecting the packer inflation in Packer and Stage Collar System.

Further design improvements

The Packer and Stage Collar system presented above also under-went several key improvements as part of the preparation for this project to increase further its reliability. The second version of the tool integrate new innovative features, amongst which:

- Strengthened closing sleeve with dual lock mechanism to provide more assurance of the stage tool and packer closure.
- Implementation of proprietary double D-seal mechanism, for gas tight versions.
- Removal of the over-coupling and integration of the packer inflation path into a single coupling between the stage tool and the packer. This removes any potential leak path through the over-coupling thread towards the annulus.
- Increased flow-by area through the ports inside the coupling to reduce risk of plugging due to debris or loss circulation material.
- Inversion of the packer to have the moving sub at the bottom, moving up – this drastically increase the effective diameter in which the packer can be set compared to the prior system which carried the risk of the top sub to exit the over-coupling and lose the ability to inflate in washed out holes.

Case History

Depicted in Figure 10, the lower stage was planned at a depth of 1,000 ft MDRT while the upper stage was planned at 632ft MDRT

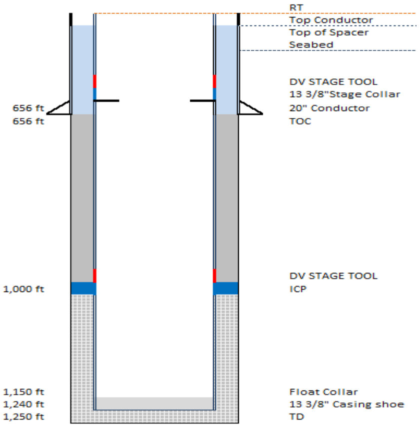


Figure 10: Well Schematic for 3 Stage cement Job

Two different approaches were adopted for the Packer inflation.

Approach for Cased Hole Scenario:

The 2nd stage cement is completed & the free fall opening device is dropped to expose the port & the rupture disc rated as 1450 psi. Once the plug lands & is pressurized to primary opening pressure (320 psi), pressure is increased slowly by steps of 200-300 psi & waiting 2-3 mins at each step until full packer inflation. The pressure is increased to the secondary opening pressure (1450 psi) to burst the rupture disc & establish communication with the annulus to prepare the hole for the 3rd stage cement job.

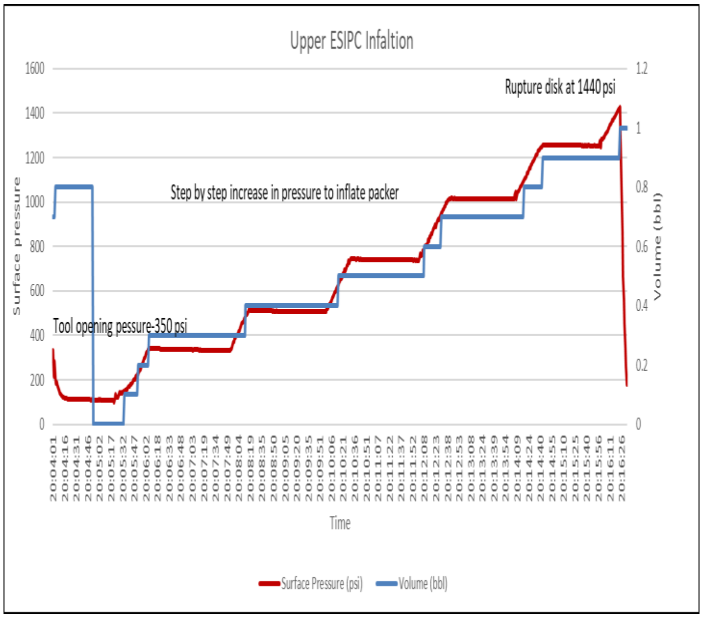


Figure 11: Packer Inflation Chart for cased hole scenario.

The figure 11 depicts the pressure profile during the packer sleeve shifting & packer inflation operation of the upper ESIPC (Stage Cementer Packer Collar) for the well.

After the cement is pumped, the 3rd stage closing plug is dropped to displace cement, bump & pressurized to close the stage tool sleeves allowing to pressure test the casing to 2000 psi.

Modified Packer Inflation approach for Open Hole Scenario:

The 1st stage cement is completed, the free fall opening device is dropped to expose the port & the rupture disc rated as 1450 psi. Once the plug lands & pressurized to primary opening pressure (320 psi), pressure is increased slowly by steps of 200-300 psi till 500 psi or a total of 0.6 bbls have been pumped to inflate the packer. After the pressure stabilizes at 500 psi or 0.6 bbl volume pumped, the pressure is increased sharply to 1450-1650 psi. i.e., the secondary opening pressure to burst the rupture disc & establish communication with the annulus to prepare the hole for the 2nd stage cement job.

The sharp increase of the pressure from 500 psi or 0.6 bbls is to limit the volume be injected into the packer & prevent over-inflation.

The sudden increase in pressure is achieved by pumping at high rates creating a high pressure drop at the check valve of the packer causing the rupture disc to burst & prevent additional fluid to be injected into the packer.

The packer retains the volume injected prior to the rupture disc leading to a soft set annulus packer which can still support the cement column & help in achieving isolation.1

The Figure 12 is the job chart of one of well on which the above-mentioned inflation procedure was applied & managed to achieve the required top of cement.

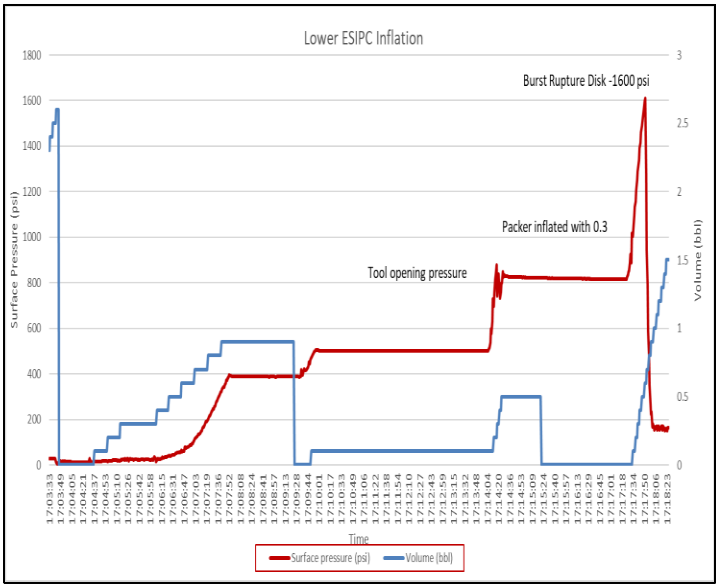


Figure 12: Packer Inflation Chart for Open Hole Scenario

Rupture Disc Optimization:

The Stage tool packer collar had a burst disc rated to 1800 psi with 10% tolerance when the tool was received in country. In a scenario of cement rising above the tool, the secondary opening pressure would exceed 2000psi. Resulting necessary to limit the pressure to 2000 psi due to concerns of casing failure if pressure exceeded 2000 psi.

A rupture disc of 1450 psi was mobilized from the manufacturing plant and installed locally in Qatar to tailor the tool & pressure requirements as per the well needs.

This allowed to drop the secondary opening pressure to 1450 psi & eliminate the risk to reach 2000 psi while ramping up the pressure.

Lessons Learnt:

An irregularity related to the primary opening pressure of the lower ESIPC (Stage Cementer Packer Collar) tool was observed. Instead of the expected 320 psi, it opened at a significantly higher pressure of 900 psi.

The space between the lower ESIPC (Stage Cementer Packer Collar) & baffle adapter is constrained, and the movement required for the opening sleeve to overcome the fluid's compressibility accounts for the observed increase in shifting pressure.

Given:

- The lower tool is 170 ft above the shut-off plug.
- The sleeve needs to shift 4.41 inches to open the ports, equivalent to 0.3675 ft.
- Using the compressibility formula dV/V = -k * dP, where the cross-section of the fluid is constant.
- The value of the compressibility constant (k) for water under pressure is 3.9 x 10^-10 Pa.

Calculations:
dV/V = -0.3675 / 170 = -0.00216

Using the compressibility formula,
dP = 0.00216 / (3.9 x 10^-10) = 5.54 MPa = 804 psi

Therefore, the additional pressure required to shift the sleeve even after the pin shear is calculated to be approximately 804 psi due to the compressibility of the fluid.

The observed increase in shifting pressure for the lower tool is obviously attributed to the compressibility of the fluid in the confined space, which necessitates additional pressure to move the sleeve beyond the point where the pin shears.

This lessons learnt has been captured as a part of all multiple stage cement jobs & recommended distance between baffle collar (shut off plug landed depth) and lower stage tool should be 500 ft to avoid this scenario.

By implementing these lessons and integrating them into standard operating procedures, subsequent jobs benefitted from a more informed and proactive approach, reducing the likelihood of encountering similar anomalies and enhancing overall operational efficiency and safety.

Conclusions

To date, four 13-3/8’’ Casing Jobs with two ESIPC (Stage Cementer Packer Collar integrated with packer - plug operated) were successfully completed without any issues. Both packers gave positive indication of inflation and reached the estimated hole size without burst.

Innovative methodology tailored under wellbore conditions scenario was successfully implemented in washed-out deviated holes under total losses, allowing wellbore integrity in all cases. The essence of successful cement job and zonal isolation lies in volume-based pressure ramping procedure to limit the packer inflation in unknown hole size/ washed out section. Rupture disc pressure tailored to wellbore conditions was successfully implemented avoiding excess casing integrity pressure during pressure ramping up.

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Nomenclature

BHA = *Bottomhole assembly*
ERD = *Extended Reach Drilling*
TVDRT =*True Vertical Depth referenced to Rotary Table*
MDRT =*Measure Depth referenced to Rotary Table*
ESIPC = *External Sleeve Inflatable Packer Collar*
CP = *conductor pipe*
ROV = *Remotely Operated Vehicle*