Successful Gas Shutoff Operation Using a Coiled Tubing Telemetry System: A Case History

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Summary

In a deviated well in the Caspian Sea, the gas/oil ratio (GOR) increased rapidly in 2017. The result was an oil rate decline with several choke backs to manage GOR buildup. After performing two production-logging jobs, it was confirmed that 76% of the gas production was coming from four upper perforations. The main objective was to perform a gas shutoff (GSO) treatment in two stages to reduce gas production by squeezing polymer into the formation and setting packers at a 59° deviation inside a 9⅝-in. casing for temporary isolation of the middle and lower production sands.

Fifteen runs were performed with a tube wire-enabled coiled tubing (CT) telemetry (CTT) system that consists of a customized bottomhole assembly (BHA) that instantaneously transmits differential pressure (DP), temperature, and depth data to the surface through a nonintrusive tube wire installed inside the CT. For the first time in the region, a tension, compression, and torque (TCT) subassembly was deployed to control the entire setting/retrieval process with accurate downhole upward/downward forces. CTT technology was a key element to successfully set two through-tubing inflatable retrievable packers (TTIRPs) by performing casing collar locator correlations at the tubing end, which was 133 and 228 m [measured depth (MD)] shallower from the setting depths. In addition, during the second GSO operation, the GSO gel system crosslink time was modified on the basis of the actual bottomhole temperature (BHT) recorded with the CTT system. Finally, during the third GSO operation, treatment placement was improved, spotting more GSO gel system inside the casing section and avoiding further treatments.

After successful placement of the GSO gel system, a drop from 15.5 to 4.5 MMscf/D in gas production was observed (GOR reduction from 11,000 to 750 MMscf/bbl) with an oil rate increment from 1.4 to 6.04 Mbbl/D. Furthermore, after the gas reduction, the operator was able to produce between 1.5 and 2.0 Mbbl/D from other wells that were choked back on the basis of gas handling capabilities limitations. In the short term, GOR reduction sustained at 3,000 MMscf/bbl and 3.0 Mbb/D oil rate.

The novelty of using the CTT system and TCT subassembly for real-time monitoring of BHA data proved to be beneficial for positioning two TTIRP, modifying GSO gel system design, placing it precisely across target intervals, and retrieving two TTIRPs that in the end provided direct and positive financial impact for the operator.

Well Background: Challenges and Proposed Solutions

The well was initially completed as a water injector in June 2008, but in April 2012 was recompleted as a producer from upper sands. Starting in Quarter 3 of 2017, the GOR increased rapidly, which resulted in an oil rate decline, together with several choke backs to manage GOR buildup **(Fig. 1).** Two production logs run in 2017 and 2019 showed that 76% of the gas production was coming from different intervals (80 m combined) of upper perforations as follows: 3893 to 3917 m, 3922 to 3937 m, 3983 to 3999 m, and 4005 to 4030 m (MD). However, a decision was made to combine these four intervals into two selected (intended) ones to increase the success of the GSO gel system placement and serve as a baseline for chemical treatment performance tackling gas breakthrough issues, because the operator may encounter similar issues with an increasing GOR profile in the future.

Fig. 1—Production history.

Fig. 2 shows a well schematic, along with the proposed treatment stages to meet the target of squeezing polymer-based fluid into the gas bearing formations that were identified earlier. Isolation TTIRP was required to achieve two stage treatments separately in a 59° deviation inside a 9⅝-in. casing. A top-to-bottom approach was selected because it involved less risk and because the well had enough

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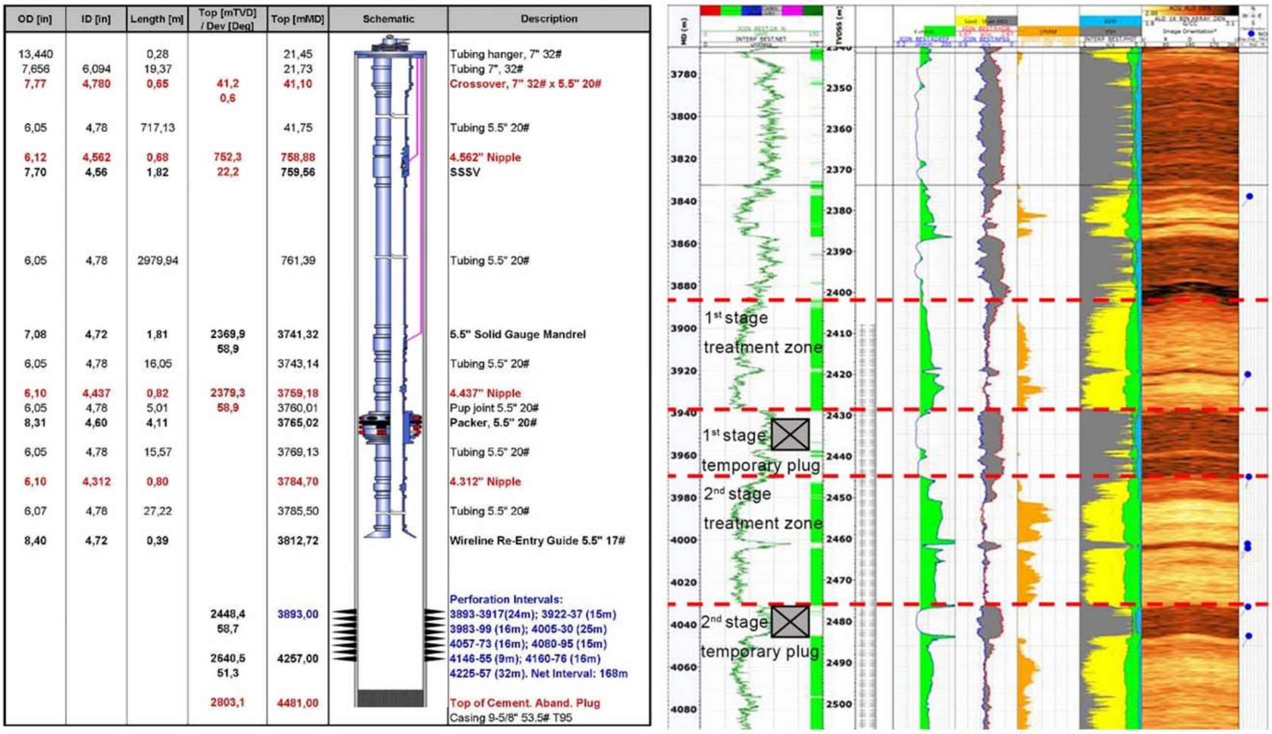
rat hole and a high risk of being unable to pull the TTIRP through the tubing restrictions. To deploy the GSO gel system properly across zones of interest, a CTT system with 2⅞-in. TCT subassembly was selected for accurate placement and indicators. TTIRP is another enabler to divert the GSO gel system squeezed into two intervals and to temporarily isolate the lower zones.



OD [in]	ID [in]	Length [m]	Top [mTVD] / Dev [Deg]	Top [mMD]	Schematic	Description
13,440		0,28		21,45		Tubing hanger, 7" 32#
7,656	6,094	19,37		21,73		Tubing 7", 32#
7,77	4,780	0,65	41,2 0,6	41,10		Crossover, 7" 32# x 5.5" 20#
6,05	4,78	717,13		41,75		Tubing 5.5" 20#
6,12	4,562	0,68	752,3	758,88		4.562" Nipple
7,70	4,56	1,82	22,2	759,56		SSSV
6,05	4,78	2979,94		761,39		Tubing 5.5" 20#
7,08	4,72	1,81	2369,9 58,9	3741,32		5.5" Solid Gauge Mandrel
6,05	4,78	16,05		3743,14		Tubing 5.5" 20#
6,10	4,437	0,82	2379,3	3759,18		4.437" Nipple
6,05	4,78	5,01	58,9	3760,01		Pup joint 5.5" 20#
8,31	4,60	4,11		3765,02		Packer, 5.5" 20#
6,05	4,78	15,57		3769,13		Tubing 5.5" 20#
6,10	4,312	0,80		3784,70		4.312" Nipple
6,07	4,78	27,22		3785,50		Tubing 5.5" 20#
8,40	4,72	0,39		3812,72		Wireline Re-Entry Guide 5.5" 17#
			2448,4 58,7	3893,00		Perforation Intervals: 3893-3917(24m); 3922-37 (15m) 3983-99 (16m); 4005-30 (25m) 4057-73 (16m); 4080-95 (15m)
			2640,5 51,3	4257,00		4146-55 (9m); 4160-76 (16m) 4225-57 (32m). Net Interval: 168m
			2803,1	4481,00		Top of Cement. Aband. Plug Casing 9-5/8" 53.5# T95

Fig. 2—Well schematic/proposed solution (selective treatment).

CTT System

During the last 15 years, CTT systems with either fiber optics (Khaidir et al. 2014; Webb et al. 2014) or wire (Livescu et al. 2015a, 2015b, 2017) have been extensively used in the industry. The recent development of a new generation of CTT systems has shown that most of these jobs will benefit from real-time downhole data, such as casing collar locator (depth), pressure (internal, external), and temperature (internal, external), which in the end translate into increasing operational efficiency and lowering operational costs. Some of these benefits have been presented in previous papers (Mallanao et al. 2015; Blanco et al. 2017; Livescu et al. 2017), but we will present only the ones related to this operation:

- Depth control for perforating and plug/inflatable packers/cement retainer setting
- Monitoring of tool performance downhole in the following cases: Downhole pressure changes during plug/inflatable packer/cement retainer setting/unsetting process and during the operation
- Operations that require monitoring downhole pressure and temperature in real time, such as to improve fluid placement and diversion during matrix stimulations and conformance jobs

The main difference of the new CTT system is the transmission medium inside the CT string to transfer downhole data to the surface: monoconductor encapsulated in a 0.125-in. Inconel tube **(Fig. 3)** or a 0.125-in. optical fiber. They differ in how the electrical power is transferred from the surface to downhole sensors. The CTT wire (Taggart et al. 2010; Livescu et al. 2015a, 2015b) not only transfers real-time downhole data to the surface but also transfers electrical power continuously from the surface to the downhole sensors. The optical fiber can transfer only downhole data to the surface. In this system, the BHA requires batteries to power the sensors (Blanco et al. 2016). Based on this, the main advantage of the wire CTT system is that it can provide electrical power for tools without limitations of time. The main advantage of the optical fiber CTT system is that it can record distributed temperature data along the entire CT length.

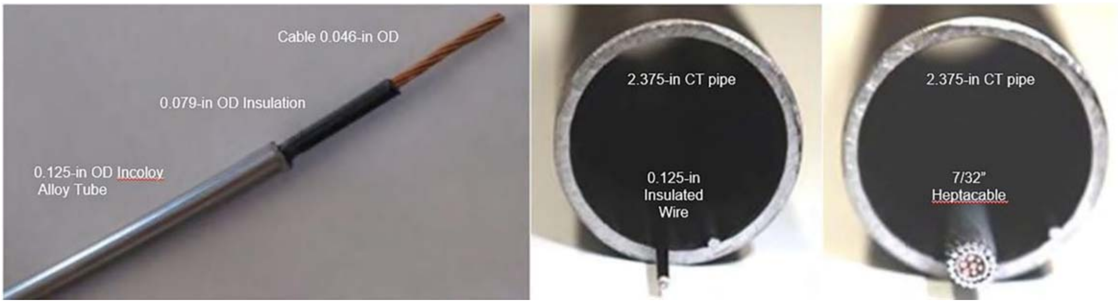


Fig. 3—0.125-in. insulated wire.

The 0.125-in. CTT system wire has a minimal effect on flow rates, friction pressure, and weight to the CT string and provides a free passage for balls, making BHA and tools with ball-operated mechanisms possible (Livescu et al. 2015a, 2015b). In addition, it is compatible with most monoconductor casedhole wireline tools and oilfield fluids such as solvents, acids, gels, and slurries. The other components of the CTT system **(Fig. 4)** are as follows:

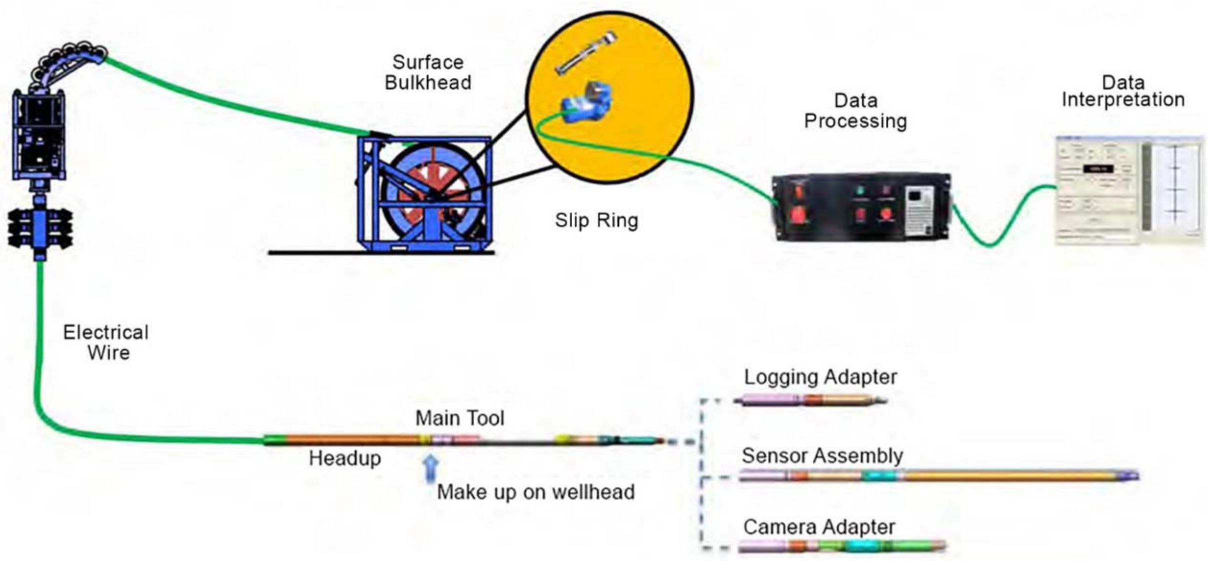


Fig. 4—CTT wire system components.

Surface Hardware. The wire goes out the CT reel core end through the surface bulkhead, sealing the outer tube and isolating fluid pressure. A conventional slip ring collector is used to allow an electrical connection through the rotating drum to the surface data collection and power system. The downhole data are finally displayed and interpreted in real time.

BHA. BHA comes in three different sizes (2.125, 2.875, and 3.5 in.) and has two sections. The top (headup) provides an electrical and mechanical connection to the rest of the tools and facilitates a quick change between the three bottom parts as follows:

- Sensor assembly: The sensor assembly combines sensors for depth (casing collar locator), pressure (external, internal), and temperature (external, internal) and has double flapper check valves, hydraulic disconnect and circulating valve for contingency purposes. Below this assembly, conventional tools can be connected as follows: high-pressure jetting tools, downhole motors, retrievable packers, plugs, and fishing and hammering tools.
- Logging adapter: The logging adapter connects the CTT wire to the logging tools, and no circulation path is required. Same as above, for contingency purposes, it has double flapper check valves, a release subassembly, and a circulating subassembly.
- Camera adapter: The camera adapter connects cameras with the front and lateral views, allowing clean fluids to pump through it for washing the camera lenses and improving downhole images (Livescu et al. 2015a, 2015b).

Description of the TCT Subassembly

The TCT subassembly (Kubeisinova et al. 2018) is an addition to the sensor assembly, and it enables real-time monitoring of axial forces (pull and push) and radial forces (torque) exerted on the BHA (Garner et al. 2016). These forces are only mechanical loads because the hydraulic forces caused by hydrostatic or pumping pressures are calculated by algorithms. To increase the accuracy of the measurements and to further eliminate the influence of the hydraulic forces, tare check boxes for axial and radial loads enable the operation for "zero" the TCT values just before the event when very accurate measurement is required. Technical specifications are detailed in **Table 1.** Among the benefits that are related only to this operation are the following:

- Fishing: Axial forces can be used to confirm that the BHA is latched to the fish and to verify whether a jar/accelerator has been activated. When the fish is free, the added weight could confirm that the fish is free for extraction, avoiding miss runs.
- Cleanout: In highly deviated wells, the top of sand/gel can be identified, which helps during the execution of the removal operation.
- Setting tools: Setting tools apply specific weight on bit during inflatable packer and straddle setting operations. For patches, the downhole weight can be placed in neutral before the setting process starts.

Dimensions and Ratings		Sensor Capabilities	
OD	2.875 in.	Axial load range	–10,000 to 56,000 lbf
Maximum external pressure	9,000 psi	Axial measurement error	<5%
Maximum temperature	149°C	Torque range	1,500 ft-lbf
Maximum DP	5,000 psi	Torque resolution	<20 ft-lbf
Maximum flow rate	8 bbl/min	Torque error margin	<2%

Table 1—TCT subassembly specifications.

Fluid Selection and Design

For this application, rigid gel (polyacrylamide-based gel) was considered the best solution because of its high effectiveness for near-wellbore GSO. This GSO gel system develops a rigid polymeric gel capable of penetrating the matrix before activation, which happens after being exposed to specific temperature conditions. The system produces a high-strength crosslinked synthetic polymer gel after activation and is particularly useful for treating production near-wellbore problems for which complete blockage is required. The system is a polyacrylamide-based fluid crosslinked with a combination of organic crosslinkers, aided by activators depending on BHT. The low molecular weight of the polymer and lower viscosities per concentration permits the gel to penetrate a matrix with permeabilities of 25 md or greater. Another advantage of the GSO gel system is low shear sensitivity. Because of the molecular size of the gelling agent and the resulting lower viscosities per concentration, surface handling equipment does not tend to degrade the solution by polymer chain breakage. From the operational point of view, one of the main advantages of the system over others is that it can be jetted after the treatment rather than drilled out of the wellbore.

The GSO gel system mainly consists of three components: gelling agent (polymer), organic crosslinker, and activator. Gel properties can be optimized for a certain requirement by adjusting the concentrations of those components. The fluid was designed for this treatment by taking the following into consideration:

1. Height of the zone to be treated
2. Formation porosity
3. Radial treatment radius
4. Bottomhole static temperature
5. Bottomhole injection temperature (BHIT)
6. Injection rate

The first three points were used to calculate gel volume to be injected into the zone. Resulting from the long length of intervals, the zone was divided into two sections: the upper section from 3893 to 3917 m (MD) and from 3922 to 3937 m (MD) and the lower section from 3983 to 3999 m (MD) and from 4005 to 4030 m (MD). The gel volume calculated was 430 and 440 bbl for the upper and lower intervals considering height (39 and 41 m), 23% porosity formation, and a 5-ft radial treatment radius. Item Numbers 4, 5, and 6 were used to design GSO gel system properties. They were formulated using BHIT for working time and the bottomhole static temperature for stability. Working time can be controlled from less than 1 hour to more than 8 hours for reservoir temperatures from 52 to 107°C by adjusting the activator concentration. After this, the GSO gel system formulation was optimized in the laboratory for the working time from 6 to 8 hours at 62°C considering a 1-bbl/min injection rate. It was required that during the working time, the GSO gel system should have a viscosity from 100 to 170 cp. Several formulations were tested by varying activator concentrations to achieve the desired properties **(Fig. 5).**

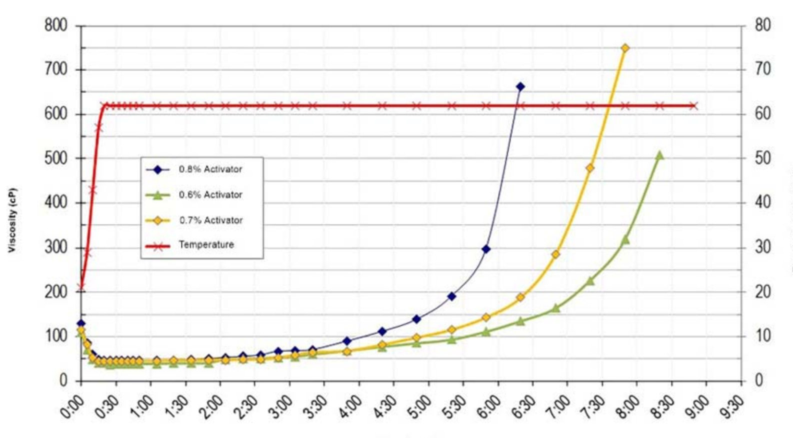


Fig. 5—Gelation time versus activator concentration.

For extra insurance and a better understanding of the working time, a fluid loss cell loaded with filtering medium (approximate permeability of 250 md) was used at 62°C. This test ensures that the GSO gel system would be able to penetrate the formation during working time. A sample was loaded into the fluid loss cell with a filtering medium. Approximately 100 psi DP was applied to the cell. Every 30 minutes, the bottom plug was opened, and the flow of gel was checked through a filtering medium. The flow was stopped after 8 hours, indicating a safe working time. To test stability, it was kept in a water bath at 62°C for 7 days. No instability and no syneresis were detected during this period. GSO gel system strength was evaluated based on the Marathon Oil Company gel strength coding system. It showed a gel strength of Code I (Code I – rigid gel: there is no gel surface deformation upon inversion) **(Fig. 6).**

Job Execution

Fifteen runs with the CTT system were done to complete the operation as follows.

Runs 1 and 2: TTIRP Setting Attempt and TTIRP 1 Setting at 3946.3 m (MD). On location, the decision was made to set TTIRP 1 in live conditions because after a bullheading operation, the well still had positive pressure [shut-in wellhead pressure (SIWHP), 2,700 psi]. While running in the hole (RIH), the DP between CT and wellbore was increasing. Two pumping attempts via CT were done to reduce DP without success because TTIRP inflation process started inside tubing. A decision was made to pull out of the hole (POOH) to the surface and wait for brine delivery to do another bullheading operation before RIH and pump via CT and wellbore annulus (back side) to keep SIWHP low, reducing the risk of reaching CT collapse pressure. After depth correlation at the tubing end, TTIRP 1 elements were positioned at 3946.3 m (MD) to not inflate them in a casing joint, which could have a negative sealing effect of lower zones. **Fig. 7** shows the entire setting process of TTIRP 1.

Fig. 6—Solid gel after 7 days at 62°C.

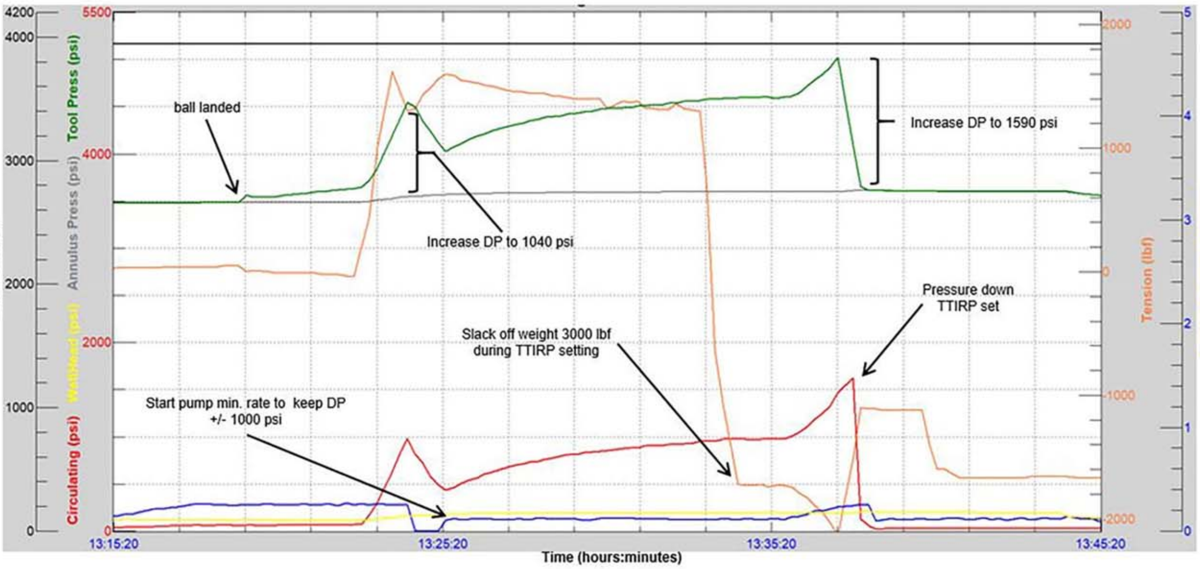


Fig. 7—TTIRP setting process at 3946.3 m (MD).

Run 3: GSO Treatment 3893 to 3917 m (MD) and 3922 to 3937 m (MD). Before RIH, the SIWHP was 1,380 psi lower than the previous run, which was a good indication of the TTIRP 1 lower zone isolation. After performing correlation at the tubing end, BHA was run to 3937 m (MD), and an injectivity test via CT string was started. Based on injection results, GSO gel system target volume preparation started mixing polymer and 0.6% activator. The crosslinker was added to 50 bbl batches right before pumping to avoid any uncertainties in the case of stopping the operation for any reason. Samples were collected from each batch after adding the crosslinker during the execution. The collected samples were stored in the water bath at 62°C. In addition, a sample from the first batch was placed in the rheometer (at 62°C) for continuous measurement of viscosity to understand the gel properties downhole. Pumping started through CT string with 15 bbl of spacer followed by the GSO gel system. Because SIWHP was slowly increasing, the decision was made to place GSO gel system in stages from bottom to top intervals injecting 70% of the volume in the bottom interval from 3922 to 3937 m (MD). In **Table 2,** the injected volumes at different depths can be seen. Injection rates were modified based on crosslink time tested in a water bath at design bottomhole static temperature with samples **(Fig. 8).**

During this process, SIWHP increased from 510 to 1,410 psi. CT was POOH while pumping at the minimum rate to fill displacement volume until 2627 m (MD). Then, CT was POOH to 2200 m (MD) without pumping and parked for 24 hours (well in static conditions) for crosslinking before going to the surface. Toward the treatment end, the fluid viscosity was in the acceptable range to be considered as pumpable. The samples in the water bath were checked to confirm the crosslinking **(Fig. 9).** It is important to mention that during this operation, the BHIT recorded by the CTT system was 58°C instead of 62°C, which consequently increases the working time of the GSO gel system by slowing down the crosslinking process. Despite this, the gel properties were not affected while the gel was in a liquid state and being injected, which may have created inadequate fluid diversion. As a result of the poor diversion, a majority of the gel would be diverted to a higher permeable zone, and the zone with low permeability would not be impacted.

Depth (m)	Volume (bbl)	Rate (bbl/min)	Cumulative Volume (bbl)
3937.1	60.8	0.94	60.8
3932.7	59.1	0.94	119.9
3927.0	60.8	0.94	180.7
3922.5	58.9	0.54 to 0.94	239.6
3917.8	40.1	0.54	279.7
3911.5	28.7	0.54	308.4
3906.5	38.6	0.54 to 1.0	347.0
3900.0	35.2	1.0	382.2
3893.9	35.5	1.0 to 0.54	417.7
3983.9 to 3880.0	12.7	0.54	430.4

Table 2—First GSO treatments 3893 to 3917 m (MD) and 3922 to 3937 m (MD): injected volumes.

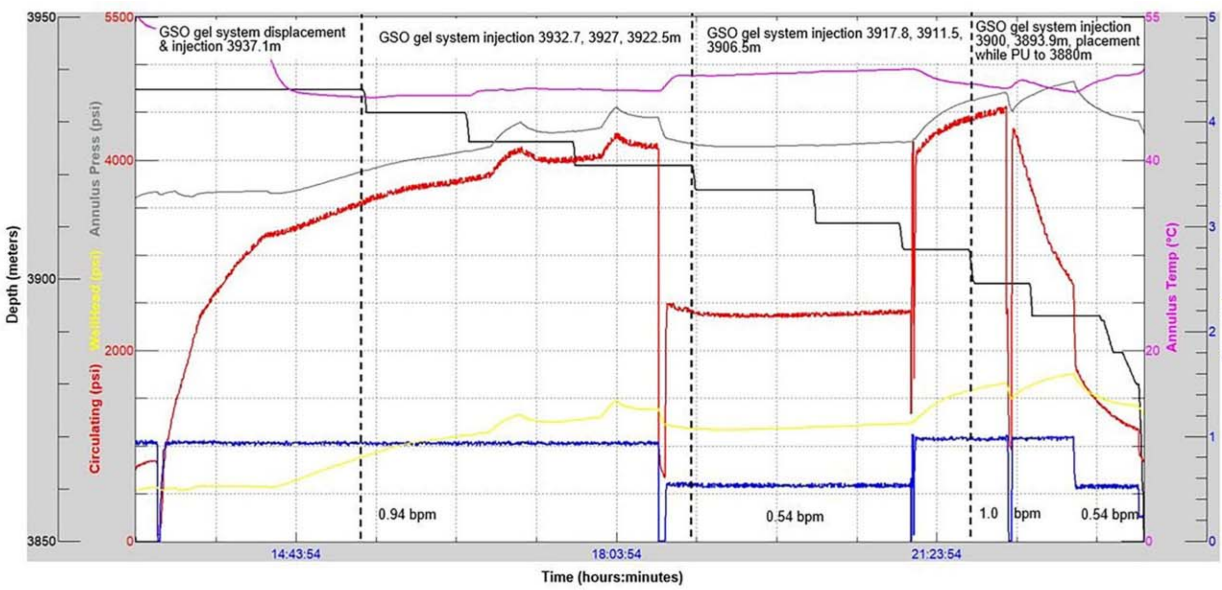


Fig. 8—First GSO treatment intervals 3893 to 3917 m (MD) and 3922 to 3937 m (MD).

Fig. 9—Crosslinked GSO gel system after 24 hours at 62°C.

Runs 4, 5, and 6: Cleanout to 3938 m (MD), GSO Treatment 3893 to 3917 m (MD) and 3922 to 3937 m (MD), and Cleanout to 3937 m (MD). The tool deployed with the CTT system provided high-pressure forward jetting to penetrate and break the GSO gel system set inside a 9⅝-in. casing up to 7 m above the top of TTIRP 1 and switched to backward jetting for cleaning purposes. This reduced the pressure drop, allowing higher annular rates to perform an effective removal (wiper trip) while POOH. During the cleanout run, no slackoff weight readings were recorded either at downhole with TCT subassembly or on CT surface weight. During the entire run, the surface returns were brine mixed with gas. On the basis of well behavior, it was decided to perform another GSO treatment in same intervals to stop gas influx. The GSO gel system pumping time and injection rate were reduced to have the first batch partially crosslinked in the formation while pumping the rest of the batches. The idea was to get fluid diversion to cover the entire zone. Moreover, the GSO gel system was designed for 58°C (instead of 62°C) because in the previous operation lower BHIT was recorded resulting from the cooling effect while injecting GSO gel system. The activator concentration was increased to 0.8%, and the design volume of 265 bbl was calculated considering a 4-ft radius of penetration. In **Table 3,** the injected volumes at different depths can be seen. After pumping the GSO gel system **(Fig. 10),** the well was left in static conditions for 36 hours until crosslinking was confirmed with the samples stores in the water bath at 58°C **(Fig. 11).** After the waiting time, CT was POOH to the surface to continue with the cleanout run.

Depth (m)	Volume (bbl)	Rate (bbl/min)	Cumulative Volume (bbl)
3937.5	64.5	0.70 to 0.52	64.5
3927.8	65.5	0.52	130.0
3916.7	62.0	0.52 to 0.32	192.0
3906.0	36.8	0.32 to 0.27	228.8
3890.0	16.7	0.27	245.5
3890.0 to 3788.0	19.5	0.35	265.0

Table 3—Second GSO treatment 3893 to 3917 m (MD) and 3922 to 3937 m (MD): injected volumes.

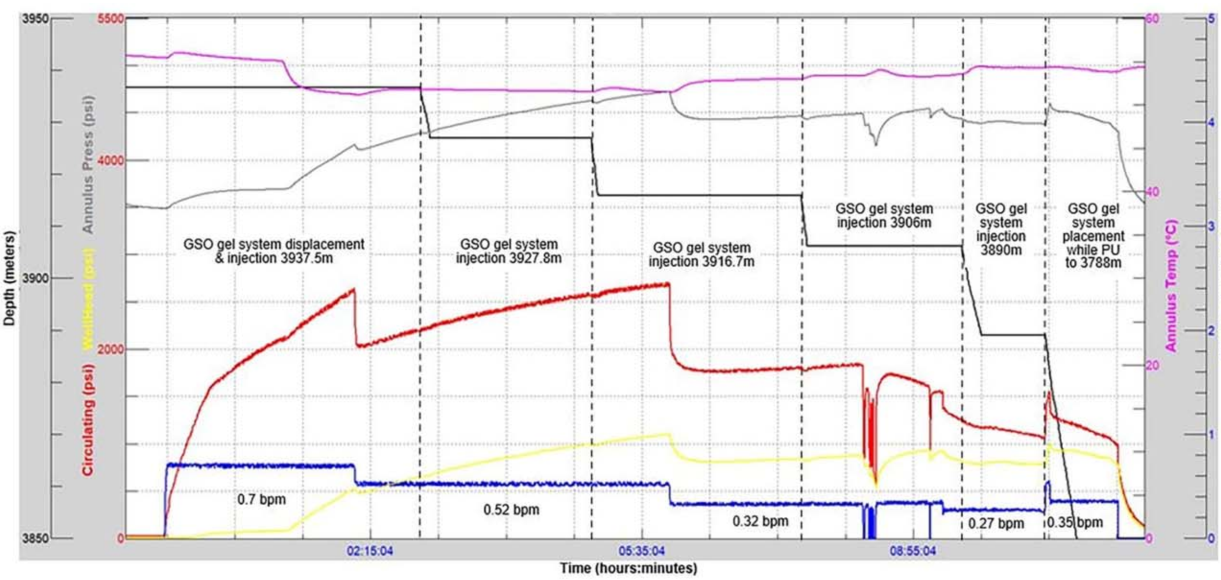


Fig. 10—Second GSO treatment intervals 3893 to 3917 m (MD) and 3922 to 3937 m (MD). PU = pick up.

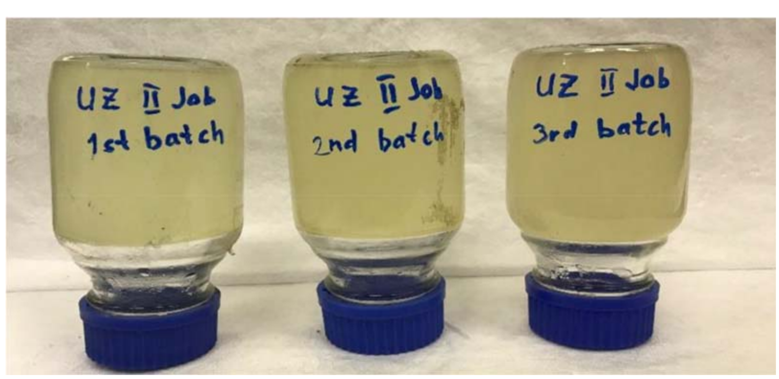


Fig. 11—Crosslinked GSO gel system after 36 hours at 58°C.

During the second cleanout run, the TCT subassembly recorded RIH slackoff weight at the same time CTP/flowing wellhead pressure/tool/annular pressures increased, and return rate reduction was seen. After, RIH weight values of TCT went back to normal, and RIH continued without any slackoff weight. During the entire run, the returns at surface were brined without gas. Based on well behavior and no gas presence, the decision was made to retrieve TTIRP 1 to proceed with the GSO treatment for the next intervals.

Runs 7, 8, and 9: Packer Retrieval Operation at 3946.3 m (MD). The first fishing BHA deployed was a shrouded 3-in. GS assembly with tapered nose cone to latch (internally) the fishing neck on top of the TTIRP. After 15 latching attempts at different pumping rates, pickup depths, and RIH speeds without success, CT was POOH to check BHA. Based on marks seen on the bottom edge, fishing BHA was modified adding two knuckle joints below the CTT sensor assembly and removing the intensifier and jar. After 15 latching attempts during the second retrieval run without success, BHA was retrieved to the surface, and it was decided to separate the knuckle joints by placing one straight bar in between, remove the shrouded 3-in. GS assembly with tapered nose cone, and install a 3.75-in.-outer diameter (OD) overshot fishing tool **(Table 4).** During the third retrieval run, six attempts were done to externally latch the fishing neck **(Fig. 12).** After waiting for the element's deflation process, CT was RIH to the end of well depth 4437 m (MD), and TTIRP 1 was left as planned.

Item	Tool Description	Tool OD (in.)	Tool Inner Diameter (in.)	Tool Length (mm)	Tool Depth (mm)
1	External grapple connector for 2-in. CT	2.875	1.1	290	290
2	Interconnect collar (spline-spline connector)	2.875	1.0	154	444
3	CTT sensor assembly with TCT subassembly	2.875	0.688	1290	1734
4	Knuckle joint	2.875	0.75	375	2109
5	Straight bar	2.875	1.0	1524	3633
6	Knuckle joint	2.875	0.75	375	4008
7	Hydraulic centralizer	2.875	0.75	1244	5252
8	Straight bar	2.875	1.0	1524	6776
9	Hydraulic centralizer	2.875	0.75	1244	8020
10	Hydraulic disconnect and circulating valve, ⅝-in. activation ball	2.875	0.563	615	8635
11	Crossover	3.130	1.0	445	9080
12	3.75-in. overshot with 2.88-in. grapple	3.750	NA	600	9680

Table 4—BHA used during Run 9: TTIRP retrieval at 3946.3 m (MD). NA = not applicable.

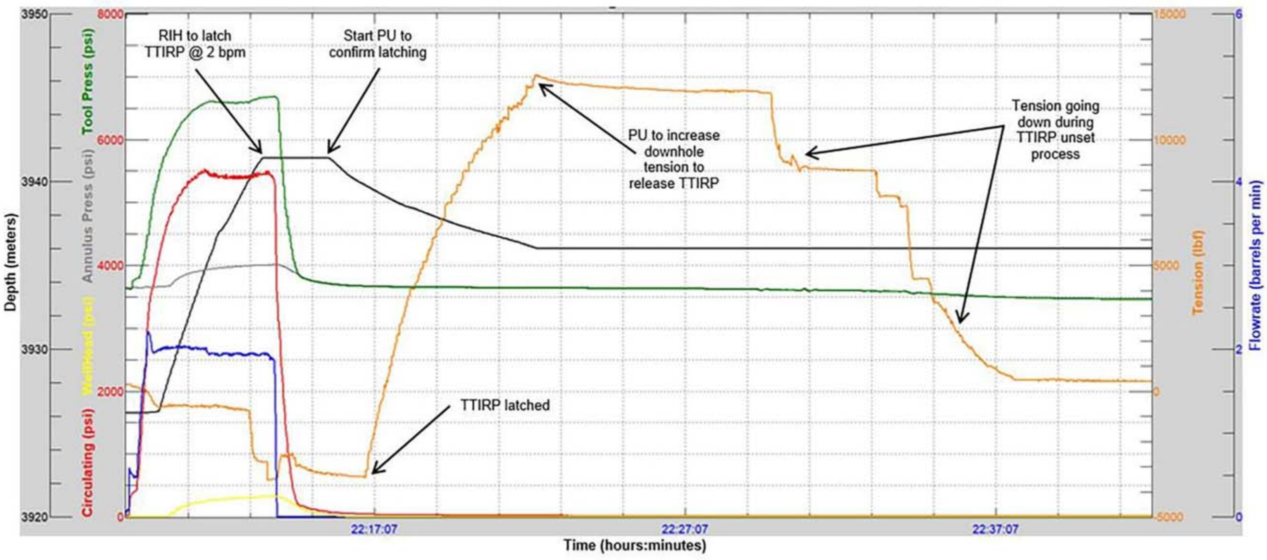


Fig. 12—Attempt No. 6 during Run 9: TTIRP retrieval at 3946.3 m (MD).

During the latching events of these three runs, the maximum slackoff weight applied was between 2,900 and 3,100 lbf measured with TCT subassembly at downhole conditions. This was very close to the values foreseen when running simulations with CT software **(Fig. 13).** Upon arrival to the surface, SIWHP was 1,100 psi. By comparing this value with the 0 psi before RIH, it was clear that bottom intervals were connected again after unsetting TTIRP 1.

Runs 10, 11, and 12: TTIRP 2 Setting at 4037.9 m, GSO Treatment 3983 to 3999 m (MD) and 4005 to 4030 m (MD), and Cleanout Run to 4033 m (MD). Before RIH, SIWHP was 1,550 psi lower than the one recorded on the first two runs before setting the TTIRP 1, which was a clear indication of GSO treatment effectiveness performed on intervals 3893 to 3917 and 3922 to 3937 m. After depth correlation at the tubing end, TTIRP 2 elements were placed at 4039 m (MD) to not inflate them in a casing joint, which could have the negative effect of sealing the lower zones. **Fig. 14** shows the entire setting process of TTIRP 2.

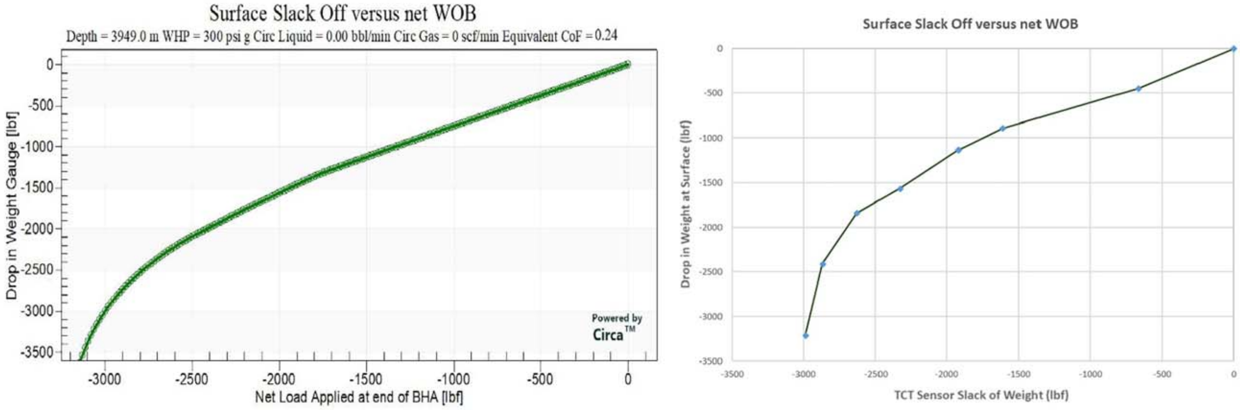


Fig. 13—Surface slackoff vs. net weight weight-on-bit (WOB) comparison (simulated vs. actual). Circ = circulating; WHP = wellhead pressure; CoF = coefficient of friction.

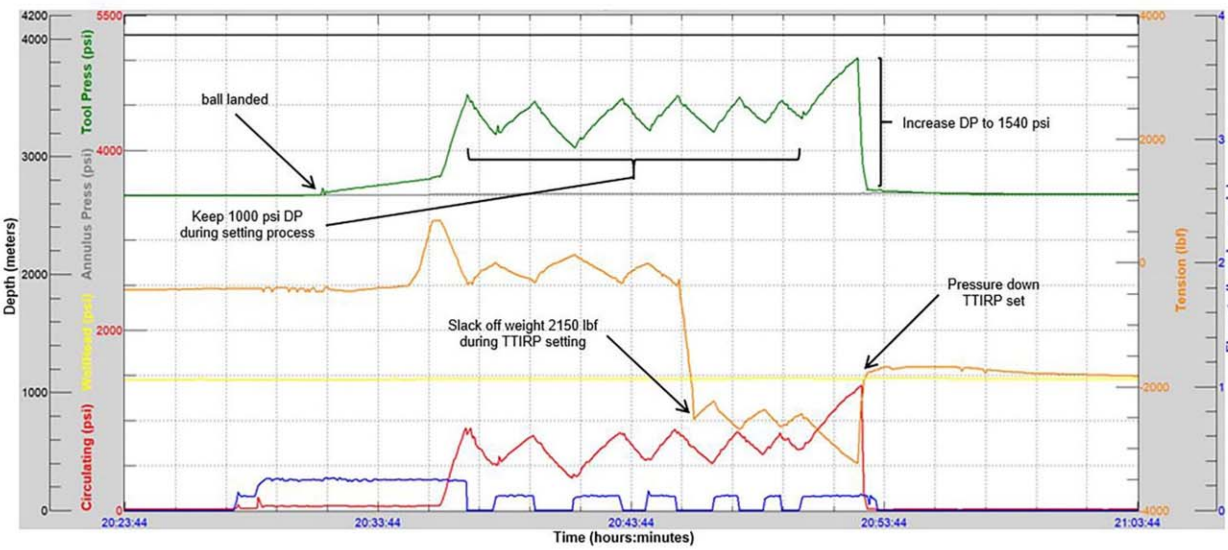


Fig. 14—TTIRP 2 setting process at 4039 m (MD).

After analyzing lessons learned from upper intervals, GSO gel system design was optimized by increasing the activator concentration to 1% for even better diversion to block the target zone on the first attempt. This percentage targeted achievement of a pumping time of approximately 6 hours with a BHT of 58°C. After depth correlation at the tubing end, GSO injection BHA was parked at 4030 m (MD), and the pumping operation was started. In **Table 5,** the volumes injected at different depths can be seen. After pumping 440 bbl of GSO gel system **(Fig. 15),** the well was left in static conditions for 36 hours. The samples in water bath were checked to confirm crosslinking **(Fig. 16).** After the waiting time, CT was POOH to the surface to continue with the cleanout run.

Depth (m)	Volume (bbl)	Rate (bbl/min)	Cumulative Volume (bbl)
4030.0	60.0	1.0	60.0
4024.0	36.7	1.0	96.7
4018.0	40.0	1.0	136.7
4012.0	40.4	1.0 to 0.8	177.1
4005.0	44.1	0.8 to 0.6	221.2
3999.0	40.4	0.6	261.6
3994.0	35.3	0.61 to 0.42 to 0.24	296.9
3989.0	38.2	0.24	335.1
3983.0	38.0	0.24	373.1
3983.0 to 3913.0	50.9	0.24	424.0
3913.0	16.0	0.24	440.0

Table 5—Third GSO treatment 3983 to 3999 m (MD) and 4005 to 4030 m (MD): injected volumes.

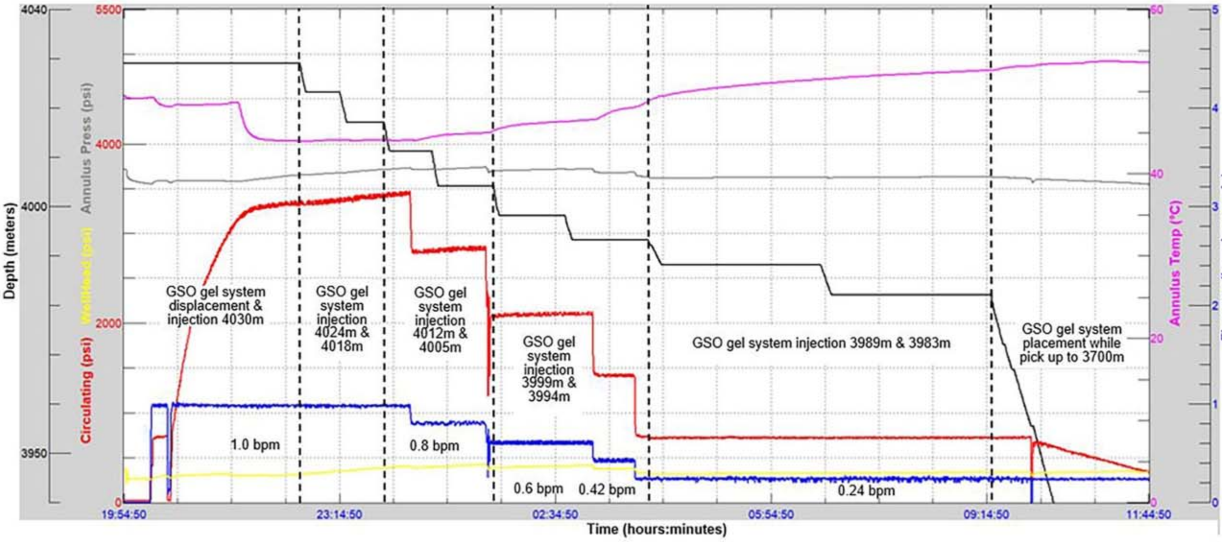


Fig. 15—GSO treatment intervals 3983 to 3999 m (MD) and 4005 to 4030 m (MD). Temp = temperature.

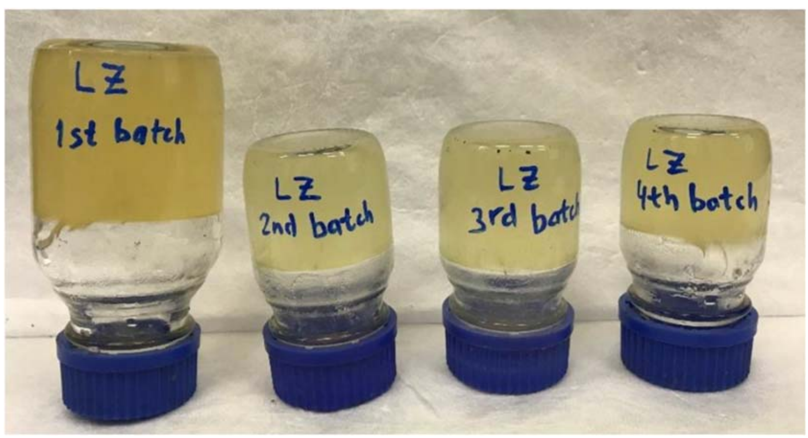


Fig. 16—Crosslinked GSO gel system after 36 hours at 58°C.

During the cleanout run, after reaching 3925 m (MD), the slackoff weight at the surface and the TCT subassembly were recorded along with CTP/flowing wellhead pressure/tool/annular pressure increase. The maximum depth reached was 3976.3 m (MD). CT BHA was tagging at shallower depths when RIH after pull tests, most likely because of GSO gel system pieces left at the bottom section of the casing. A decision was made to switch the tool to backward jetting (cleaning mode) and perform a wiper trip. During this trip, the GSO gel system was seen at the surface right after a flowing wellhead pressure quick increment to 1,150 psi. At 1215 m (MD), CT and pumping were stopped, and a second cleanout trip was started. From 3950 to 4000 m (MD), no slackoff weight was recorded in either surface weight or TCT subassembly. At 4000 m (MD), backward jetting (cleaning mode) and wiper trip were started. During this trip, while POOH CT at 3060 m (MD), the GSO gel system was detected at the surface. At 2200 m (MD), CT and pumping were stopped, and third trip was started. From 4000 to 4033 m (MD), some slackoff events were recorded at 4020 and 4028 m (MD) **(Fig. 17).** After a pull test, RIH trip continued until 4033 m (MD), 4.9 m shallower than packer element setting depth. Cleaning mode and wiper trip started, and while passing 3100 m (MD), because of return fluid cleanness, the flow rate was reduced to a minimum, and POOH was continued.

Runs 13, 14, and 15: TTIRP 2 Retrieval Operation at 4037.9 m, Nitrogen-Lifting Operation. The same BHA used during Run 9 (Table 3) was used because the setting depth was 91.6 m (MD) deeper. After 21 latching attempts at different pumping rates, pickup depths, and RIH speeds without success, a decision was made to POOH. BHA configuration was modified by removing the straight bar below the first hydraulic centralizer and placing the second hydraulic centralizer below the hydraulic disconnect to be as close as possible to the 3.75-in. OD overshot fishing tool for centralization purposes **(Table 6).** On the first attempt, the TTIRP 2 was latched **(Fig. 18).**

After waiting for the element's deflation process, CT was RIH right above TTIRP 1, and TTIRP 2 was left as planned. The maximum slackoff weight that could be applied during the latching attempt was 2,300 lbm measured with TCT subassembly at downhole conditions, which were very close to the values foreseen with CT software during this run. In addition, the real pickup weight data at bottomhole conditions measured with our TCT subassembly after latching (during packer unsetting process) were very close to the simulated pickup weight at BHA estimated by the CT software **(Fig. 19).**

After performing lifting operation RIH CT at different depths and pumping nitrogen at different rates upon arrival to the surface, the well was flowing with 1,036 psi (flowing wellhead pressure). Post-treatment results immediately after the well was put into production were as follows: oil rate increased from 1.4 to 6.0 Mbbl/D, gas rate decreased from 15.5 to 4.5 MMscf/D, and GOR decreased from 11,000 to 750 MMscf/bbl. Furthermore, an additional 1.5 to 2.0 Mbbl/D oil increment from other wells was achieved because they were chocked back due to gas management and oil optimization across the field. See **Table 7** for detailed production information. In the short term, GOR reduction was sustained at 3,000 MMscf/bbl with a 3.0 Mbbl/D oil rate **(Fig. 20).**

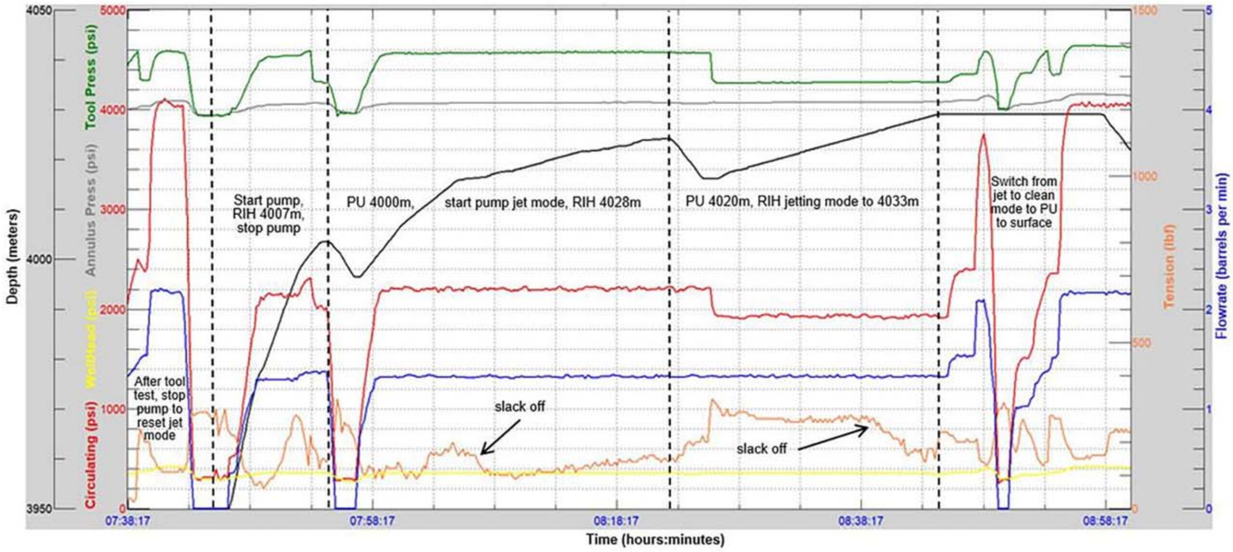


Fig. 17—Cleanout run to 4033 m (MD). PU = pick up.

Item	Tool Description	Tool OD (in.)	Tool Inner Diameter (in.)	Tool Length (mm)	Tool Depth (mm)
1	External grapple connector for 2-in. CT	2.875	1.1	290	290
2	Interconnect collar (spline-spline connector)	2.875	1.0	154	444
3	CTT sensor assembly with TCT subassembly	2.875	0.688	1290	1734
4	Knuckle joint	2.875	0.75	375	2109
5	Straight bar	2.875	1.0	1524	3633
6	Knuckle joint	2.875	0.75	375	4008
7	Hydraulic centralizer	2.875	0.75	1244	5252
8	Hydraulic valve, ⅝-in. activation ball	2.875	0.563	615	5867
9	Hydraulic centralizer	2.875	0.75	1244	7111
10	Crossover	2.875	1.0	445	7556
11	3.75-in. overshot with 2.88-in. grapple	3.130	NA	600	8156

Key: NA = not applicable

Table 6—BHA used during Run 14: TTIRP retrieval at 4037.9 m (MD).

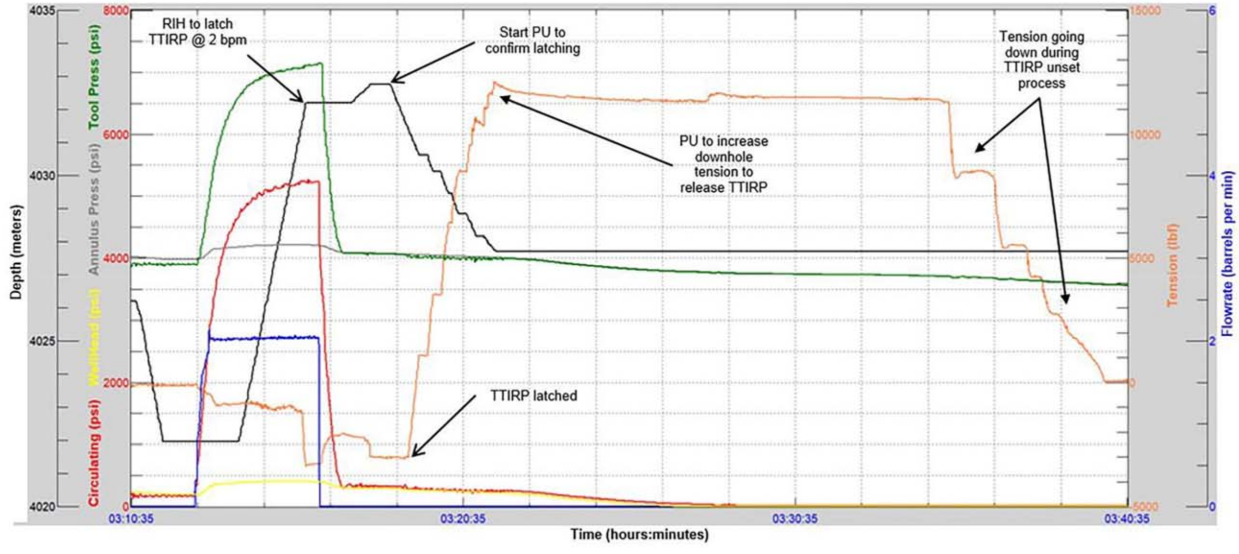


Fig. 18—First attempt during Run 14: TTIRP 2 retrieval at 4037.9 m (MD). PU = pick up.

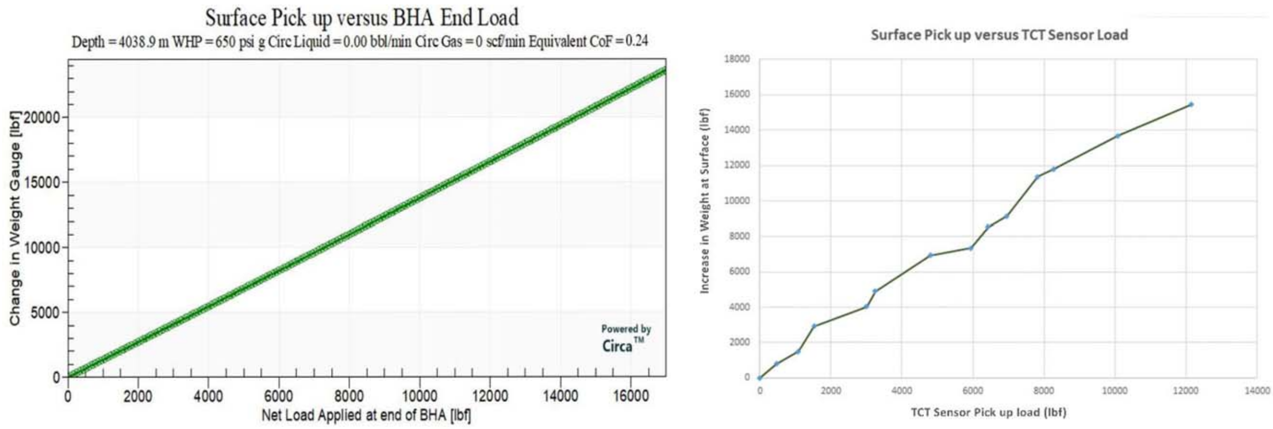


Fig. 19—Surface pickup weight versus BHA load comparison (simulated versus actual) at 4039 m (MD). Circ = circulating; WHP = wellhead pressure; CoF = coefficient of friction.

Description	Pre-Job	Post-Job
Oil rate (Mbbl/D)	1.4	6.0
Water cut (%)	0.0	1.0
Liquid rate (Mbbl/D)	1.4	6.1
Gas rate (MMscf/D)	15.5	4.5
GOR (MMscf/bbl)	11,000	750
Sand (lbm/1,000 bbl)	0.9	1.8
Flowing bottomhole pressure (psig)	3,360	3,100
Reservoir pressure (psig)	3,435	3,340
Drawdown (psig)	75.0	240.0
Liquid productivity index (bbl/D/psi)	18.8	25.3

Table 7—Production comparison.

Fig. 20—Pre- and post-GSO treatment production chart.

CTT/TCT Subassembly Systems Added Value

For the first time in the region, a 2⅞-in. TCT subassembly was use for setting, unsetting TTIRP, and high-pressure jetting GSO gel system cleanout runs. The added values were as follows:

- During TTIRP setting and retrieving/releasing runs, actual slackoff weight and pickup weight at downhole conditions could be seen at surface in real time. In addition, as per TTIRP technical data, fishing BHA needed to apply 9,600 lbf overpull to start the unsetting process. Based on actual job data, we can foresee that for future operations during the design stage, the CT string should be able to deliver at target depth minimum 13,000 lbf of pickup force. This was especially important during the operation when we had to remove the jar and accelerator from retrieval BHA (Run 8) because with the simulations performed, CT string could pick up up to 17,000 lbf without them.

- TCT subassembly slackoff weight data were extremely important during cleanout runs removing GSO gel system material set inside 9⅝-in. casing, especially during Run 12, during which three trips were done. By having accurate reading of downhole conditions, cleanout bits and wiper trips could be optimized.
- CTT system was a key element of success especially for depth correlation purposes. The 2⅞-in. casing collar locator sensor signals are not reliable inside a 9⅝-in. casing. Despite this, we were able to perform depth correlations at the tubing end, which was extremely important for defining TTIRP setting depths, during cleanout runs to not set down weight or pass beside the top of packer, and for GSO gel system injection purposes at correct depths. **Table 8** shows depth corrections done during the 14 runs before the nitrogen-lifting operation.
- During TTIRP retrieval runs, we could validate that hydraulic centralizers were working at downhole conditions because different drag forces were recorded with the TCT subassembly **(Fig. 21)** at different pumping rates and speeds as follows: −334 lbf at 0.75 bbl/min and 1.4 m/min, −440 lbf at 1 bbl/min and 2.4 m/min, −820 lbf at 1.5 bbl/min and 2.4 m/min, and −970 lbf at 2.03 bbl/min and 1 m/min.
- Based on BHIT measured with the CTT system during first GSO treatment, the activator concentration was increased considering a BHT of 58°C (4°C lower because of cooling effect) **(Fig. 22).** In addition, for the other two GSO treatments shut-in time for crosslinking was increased from 24 to 36 hours. It is important to mention that no gas influx was detected in the treated intervals after applying the previously described design changes (second and third GSO treatments).

Run	Description	CT Depth (m)	Corrected (m)	Difference (m)
2	Set packer at 3946.3 m	3778.8	3781.8	3.0
3	First GSO upper intervals	3320.0	3325.0	5.0
4	Tornado cleanout	3813.0	3814.5	1.5
5	Second GSO upper intervals	3791.4	3797.6	6.2
6	Tornado cleanout	3803.8	3811.0	7.2
7	Packer retrieval, first attempt	3813.4	3820.1	6.7
8	Packer retrieval, second attempt	3807.3	3813.0	5.7
9	Packer retrieval, third attempt	3778.0	3785.0	7.0
10	Set packer at 4,039.0 m	3753.4	3759.6	6.2
11	First GSO lower intervals	3801.5	3806.5	5.0
12	Tornado cleanout, first trip	3812.8	3814.8	2.0
12	Tornado cleanout, second trip	3807.9	3809.9	2.0
12	Tornado cleanout, third trip	3810.4	3812.4	2.0
13	Packer retrieval first attempt	3786.2	3791.8	5.6
14	Packer retrieval second attempt	3782.8	3787.8	5.0

Table 8—Depth correlations.

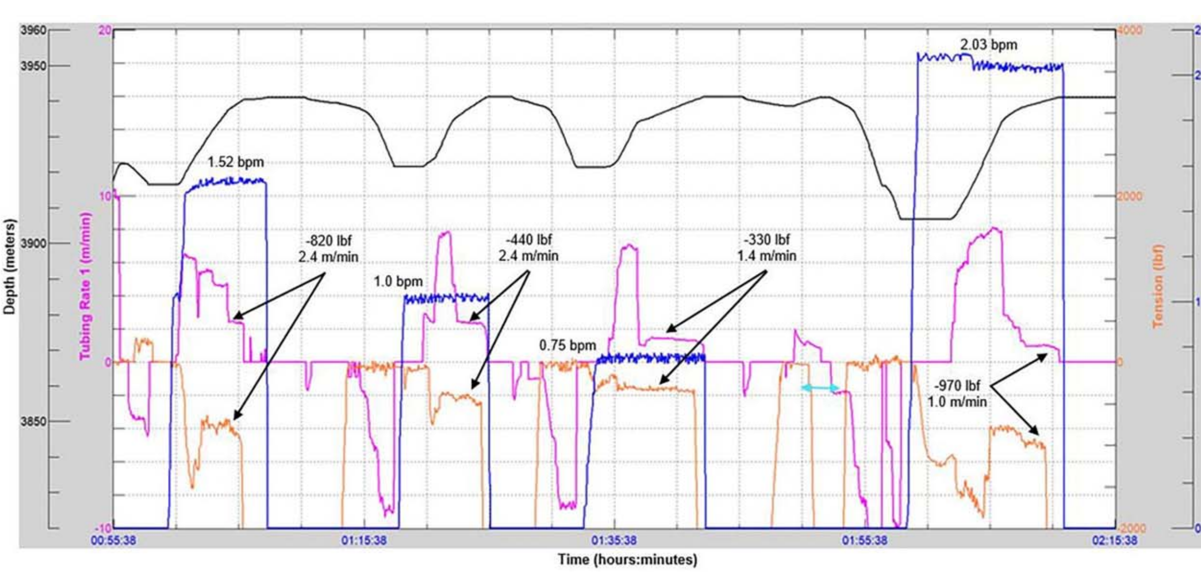


Fig. 21—Hydraulic centralizers drag forces.

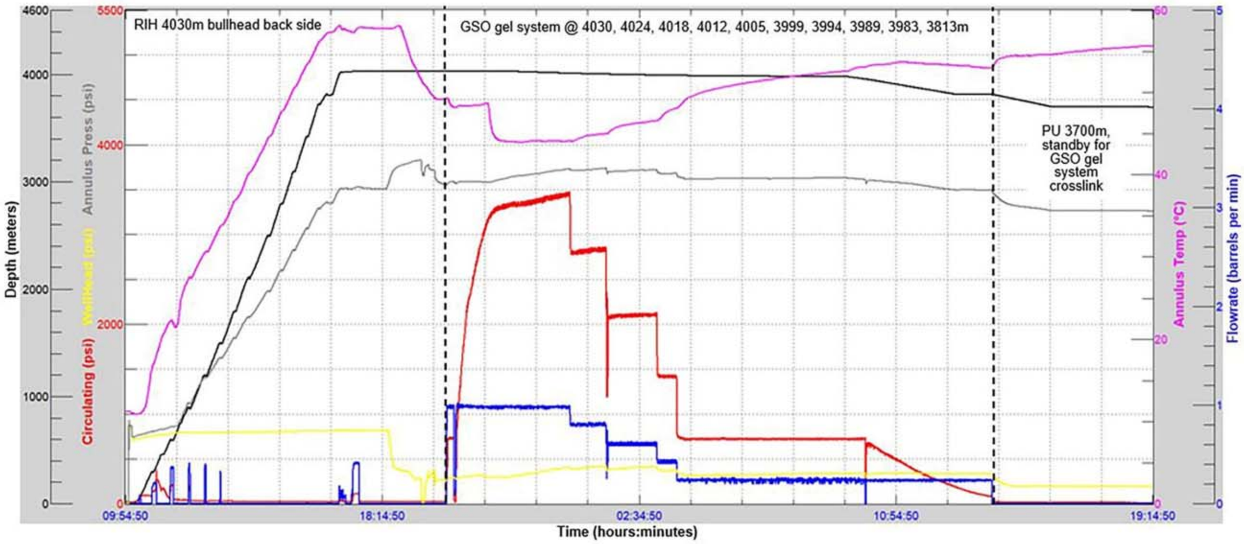


Fig. 22—Bottomhole temperature cooling effect during third GSO treatment. Temp = temperature; PU = pick up.

Latching TTIRP in 9⅝-in. Casing at 59° Deviation. One of the challenges faced with this operation was to latch the TTIRP inside a 9⅝-in. casing with 59° deviation considering that the tools need to pass through a minimum restriction of 4.312 in. In addition, one of the objectives after latching and unsetting TTIRP was to leave them at the end of the well (below deepest production zone) to avoid the risk of bringing them to the surface and getting stuck while passing their deflated elements through-wellbore restrictions. During Run 9 to set TTIRP 1 at 3946.3 m (MD), the BHA schematic shown in Table 3 was deployed and able to latch after six attempts. Despite this BHA configuration working with TTIRP 1, we could not latch TTIRP 2 set just 91.6 m (MD) deeper with the same deviation. With the BHA deployed in the next run (Table 4), a half section of 2⅞-in. hydraulic disconnect was latched externally at the first attempt by placing one hydraulic centralizer above the 3.75-in. overshot. The only setback of running this configuration was that in case the 3.75-in. overshot did not release the TTIRP 2 by pumping to leave it at the end of the well, we would have left one hydraulic centralizer in the well. In our case, we could release TTIRP 2 from the overshot by pumping, so no need to leave more tools in the well.

Conclusions

- Polyacrylamide-based gel treatment was effective in repairing gas coning in the treated well without affecting the oil production of nontreated zones. In Fig. 22, production data after the operation can be seen showing 3,000 MMscf/bbl GOR reduction sustained with 3.0 Mbbl/D oil rate. To apply successfully, we recommend redesigning the formula based on actual BHIT measured with the CTT system.
- The CTT system was proven to be a key factor for depth correlation, not only during TTIRP setting depths but also during GSO treatments.
- TCT subassembly improved the control of the TTIRP setting/unsetting process because of its capacity to measure actual downhole forces (tension/compression) in real time.
- TCT subassembly was able to confirm that hydraulic centralizers were working at bottomhole conditions because different drag forces were recorded at various flowrates.
- The BHA design for latching TTIRP inside 9⅝-in. casing at 59° deviation was proven during this job.
- It is recommended to perform a simulation for TTIRP trip in the well using the highest expected SIWHP as the worst case scenario. This information is critical to mitigate premature sets of TTIRP and CT failure due to collapse. During the second TTIRP attempt (Run 2), fluids were pumped from the back side to keep SIWHP down during the entire process.

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