Securing Annulus Abnormal Pressure Build-Up (APB) with Polymer Plug

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ABSTRACT

The life cycle of a production well was facing challenges related to well integrity issue where A-Annulus pressure tracking the tubing pressure and increased repeatedly above the Maximum Allowable Wellhead Operating Pressure (MAWOP). Several well control operations were executed to reduce A-Annulus abnormal pressure build-up (APB) with no success.

Literature and well historical studies were performed in order to secure this well, bleed and lube was ruled out owing to several attempts already performed for more than a year, but the APB keep on appearing. Bullheading is not a viable option to kill the well. Well securing planned and prepared with some options such as, mechanical barriers/plugs, cement plug or polymer plugs as temporary plug to avoid APB re-occurrence. There were some constrains in operation planning that need to be addressed carefully, with additional challenge of tight injectivity as if it was a closed system.

The polymer plug successfully stops the gas migration to surface, and secured the well from any reoccurrences of APB. The details of well control histories, operation design and planning and operation execution with the complete results and evaluation will be presented in this paper.

Keywords: annulus abnormal pressure build-up; bleed and lube; MAWOP; polymer plug

I. INTRODUCTION

After several years of production, one of oil well was having well integrity issues. There was an indication of completion accessories collapse, the drift and gauge carrier cannot go thru below the SSD (Sliding Sleeve Door) just above the packer, followed with increasing A-Annulus pressure. Some BUR (Build up Rate) tests were performed to ensure whether it is thermal or APB. Based on the results, it was confirmed that it is APB. Risk assessment carried out to mitigate the situation. The well was naturally flowing with some support from the gas injectors nearby after several years of production.

The APB in this well was starting to increase from 1200 psi to 3100 psi. Bled off management was carried out every few days as proactive step in sequence to comply with Well Integrity Management System (WIMS). The sample return during bled of confirming hydrocarbon gas (same properties as the injected gas). From the investigation, most probably gas leakage into A-Annulus from collapsed SSD inner sleeve. This APB has been diagnosed as big and fast gas leak with bleed off management to 2000 psi, and re-built up to 2800 psi in a week.

Another mitigation method to reduce the A-Annulus pressure was by lube and bleed operation to replace the gas in the A-Annulus (top up) with required fluid (treated water or brine) to reduce the surface pressure less than 2000 psi. Lower A-Annulus pressure will be maintained, followed by close monitoring to determine when another lube and bleed cycle is required.

The Maximum Allowable Annulus Surface Pressure (MAASP) was calculated based on API-RP90-2, 2016 with Simple Derating Method (SDM), where simple calculations for each annulus casing on each well by using 80% of the inner tubular collapse and 50% of outer casing/tubular collapse, the lowest value is dictated as the MAWOP for that particular annulus. In addition to that, surface equipment derating (X-mas Tree) was also used, by setting maximum pressure of 75% of its working pressure.

Based on the well schematic, the MAWOP could be calculated with Upper Diagnostic Threshold (UDT) was set at 3750 psi, based on the engineering practice of 75% of the lowest barrier rating, which is the Christmas tree rating for 5000 psi.

Based on some operating company engineering practice, any producers' wells that the A-Annulus has to be bled down twice a week to ensure that it is below the UDT, or a casing/tubing leak that big enough and tracking tubing/production casing/intermediate casing, the well have to be Shut-In and temporarily suspended. According to NORSOK Standard

D-010, 2013 there shall be two barriers available during all well activities and operations, including suspended or abandoned wells, hence barrier selection needed to ensure proper suspension as per standard.

This paper will presents results and evaluation of well control histories, operation design, planning and operation of polymer squeeze. The rule out of squeeze cementing and inflatable plug will discussed briefly.

II. METHODS

Flowchart on how the study is derived as shown in Fig.1, well completed with 3-1/2” tubing and has obstruction problem in the SSD, where any tool larger than 2.2” prevented to go below perforation which adds up the complexity which the well cannot be temporary suspended with tubing plug below the packer.

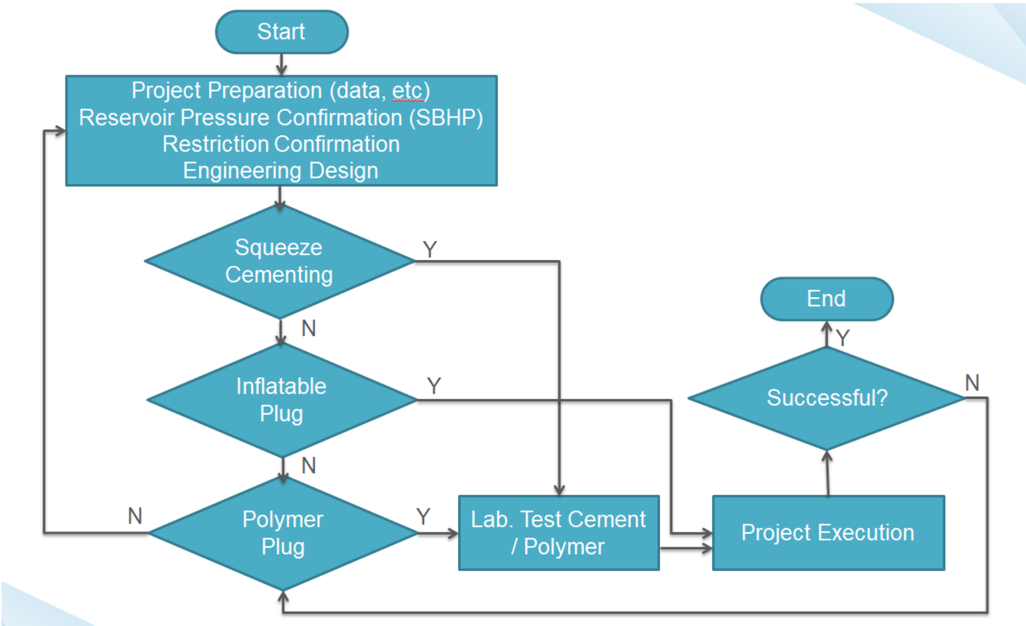


Figure 1. Flowchart of annulus APB mitigations for the case study

2.1 Cement Squeeze

The most common method used for zonal isolation for well integrity purpose was cement squeeze method. This conventional method of squeezing a cement to seal off the perforations has one disadvantage; it requires cement excess milling operation thru the zone (Naser Al-Houti et al., 2017). Pressure test after milling the squeezed section may not always good, the whole process have to be repeated all over again until good pressure test is achieved prior opening/perforations the lower section that might increase operational cost.

Squeeze cementing is commonly used to (Halliburton; Nur, Ilhami, et al., 2018):

- Seal thief or lost-circulation zones
- Repair casing leaks
- Remedy a deficient primary cement job
- Zonal change out, the water/oil or gas/oil ratio by shutting off the breakthrough zone
- Abandonment process for a non-productive or depleted zone or the entire well

In well intervention, squeeze cementing is performed with coiled tubing (CT), where a rigorous correlation and calculation shall be carried out prior job to ensure successful job. The use of CT for cement squeezing operation offers simple and relatively economic operation compared to rig or HWU (Hydraulic Workover Unit) utilization.

The sequence of squeeze cementing in CT well intervention is relatively the same with squeeze cementing with drill pipe. Cement slurry pumped thru CT and displaced in front of the formation and squeezed (with return line closed) to ensure cement could penetrates the formation pores and dehydrated. After cement already dried and hardened, cement has to be milled out prior pressure test. Milling operation requires milling bit and downhole motor (BHA-bottom hole assembly) to be run with CT to drill out the excess cement. The success of pressure test dictates whether additional squeeze cementing needs to be performed. Cement squeeze techniques could be challenging with the following reasons (Naser Al-Houti et al., 2017):

- Cement has large particle size, needed higher injection rate (higher pressure) to place the cement thru perforation hole to formation.
- Cement left in the casing must be drilled out. Sometimes the cement column is thicker than planned, which will increases operational cost.

2.2 Inflatable Plug

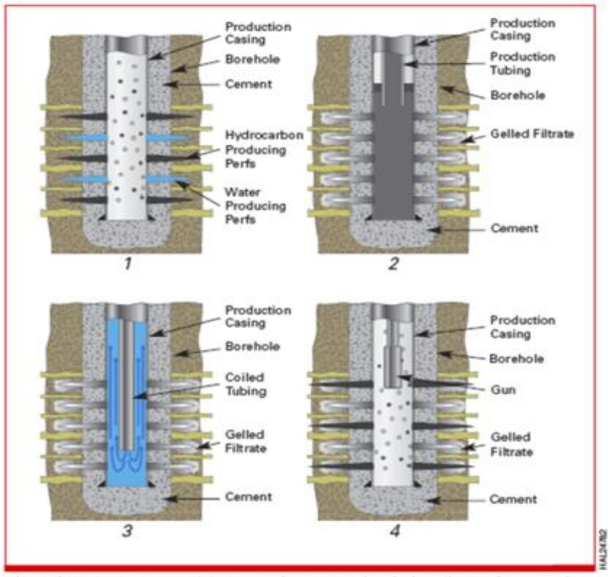
Inflatable plugs is one of the easiest suspension methods, by setting it below the packer, but the availability and delivery time for specific maximum OD of 2.125" to be able to go thru the completion restriction. Bleed and lube on tubing and A-Annulus should be done after setting the inflatable plug.

2.3 Polymer Plug

A new technology for zonal isolation or perforations shut-off was developed by several service companies. They are mainly polymers based substance that can be used as water and gas shut-off, the polymers is organically crosslinked polymers (with non cementious particles and non-bromide) that create a seal with gel-like plug that thermally activated. The crosslinking process is activated by well temperature, which depending on salinity, pH, base polymer and cross linker concentrations, the particulates (particulate conformance polymer sealant, P-CPS, or also known as M-OCP, modified organically crosslinked polymer) provide leak-off control, which leads to shallow matrix penetration of the sealant (Naser Al-Houti et al., 2017). The CPS uses a copolymer of acrylamide and t-butyl acrylate crosslinked with polyethyleneamine. Particulate uses silica flour (inert materials) to provide leak-off control (Baraa Alshammari et al., 2018).

Benefits of this polymer (Dalrymple et al., 2008):

- Low-viscosity fluid system (20-30 cp) that can be easily injected deep into formation matrix without undergoing hydrolysis and precipitation. This is better than Chrome-based polymer that tends to hydrolysis and precipitate, particularly with increasing pH and temperature.
- Adequate pumping times in environments up to 350 °F (177 °C) to obtain adequate placement time before the system undergoes the phase change from liquid to a 3-D gel structure. This transition time is completely controllable and predictable with the cross linker concentration for a given temperature.
- Effective water permeability reduction and sufficient strength for resisting drawdown pressure inside the wellbore and stopping water and gas flow. The polymer after its gelling (8-12 hours), could resist at least 2500 psi differential pressure.
- No need for zonal isolation like standard sealant operations. This slurry is bullheaded into all open perforations; the entire wellbore in the selected interval can be filled and squeezed.
- A shallow penetration of the filtrate allows for re-perforation. Non damaging.
- Unlike cement, the water-control process slurry left in the hole does not have to be drilled out, but can easily jetted out with CT, or open-end tubing.
- Not sensitive to formation fluids, and heavy metals.



The BackStop service process. (1) Some perforations produce hydrocarbon and some produce water. (2) BackStop agent is bullheaded across all perforations. (3) After setting up, excess BackStop agent in the wellbore is washed out. (4) New perforations are created in non-water-producing zones.

Figure 2. Polymer service process for the case study (Halliburton Brochures)

2.5 Well Suspension Method Selection

CT milling operation had been attempted without success to enlarge the restriction. Based on the production data, the GOR of the well started to increase, an indication of gas breakthrough in the reservoir, and increased reservoir pressure due to gas injection in the formation. Corrosion log survey was carried out to try to determine the leak point, and found some possible leak points, but unfortunately the temperature log did not show any anomalies.

A-Annulus start to ramping up, several lube and bleed operations with different brine weight was carried out to reduce the A-Annulus pressure or to kill the well with no success (the well was dead, but in one month the pressure started to build up). Some loss circulation material was used to plug the perforation with no success leaving the A-Annulus pressure increasing up to 4,100 psi with 50-75 psi/day BUR.

For suspension operation, squeeze cementing option was ruled out from the design, because the clearance between tubing mule shoe to top perforation is only 22 m. The estimated top of cement will depend on the successful killing operation to avoid any gas migration prior spotting any cement. There are some possibilities that the cement could move up and hardened on the end of tubing/mule shoe or under the packer, hence creating problems during workover that already programmed. A milling operation is required to open the cement plug for re-perforation after workover. Cement willalso creating damage to the reservoir. Inflatable plugs is changed to the last options, based on the delivery time of this inflatable plug, contingency plan if the coiled tubing operation unsuccessful. Polymer plug is the final resources that was selected.

2.6 Polymer Plug Design and Planning

The last resource was polymer plug, a material that can be pumped with CT and it will change its viscosity after exposed with pressure and temperature (gelation). The well has to be in balanced condition or killed. A sand cushion or a hi-vis should be spotted below the perforation because of 342 m rat hole below the perforations. The aim of this cushion to ensure polymer could be squeezed into the perforations. Sand pumping to rat hole will take around two days operation, and need to be re-tagged after settling to ensure top of sand. Another option, hi-vis fluid could be pumped below the perforations, and followed with the polymer plug. To save operation time, option with hi-vis is chosen. The hi-vis is design to act as cushion, several laboratory tests are performed prior operation.

Polymer laboratory test was performed in the services company laboratorium to ensure the gelation time in 3 hours and 50 minutes with 5500 psi and 220 °F as shown in Figure 3, where the phase changed from liquid to gel. The density was 1.15 SG (9.55 ppg) and viscosity of 168 cp as shown in Figure 4. The use of polymer could reduce the gas mobility.

Additional small acid wash in front of perforations also prepared to ensure good injectivity across perforations as usually used to improve injectivity prior squeezing.

Figure 3. Laboratory test of Polymer

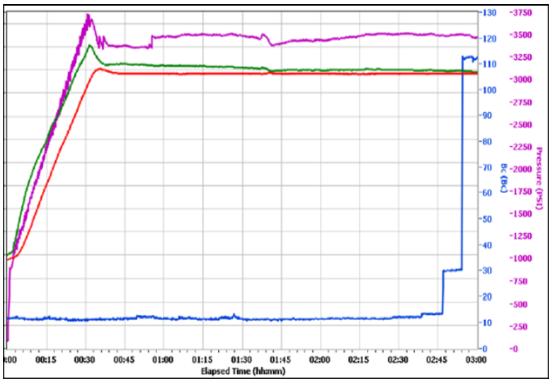


Figure 4. Laboratory test result of Polymer

The well intervention programs for this project execution:

- Restriction check with gauge cutter (GC) and recording static bottom hole pressure (SBHP) with Slickline. The aim of this operation is to know maximum tool that can go thru and current formation pressure. Calculation of kill brine is based on this data.
- Small acid, Kill well, and injectivity test.
- Zonal isolation with polymer, close return, squeeze using hesitation method.
- Injectivity/pressure test polymer plug.

III. RESULTS AND DISCUSSION

3.1 Operation Design

With close monitoring, an operation design to secure the well temporarily with CT is prepared. Well needed to be temporary suspension to avoid any pressure build up again prior workover. Temporarily securing method with polymer plug after the well is killed to avoid any A-Annulus build up reoccurrences. The use of CT was chosen to effectively kill the well (nozzle below the perforations) and to ensure that the squeezed material could be maintained below the end of tubing (EOT), as this is the only feasible option. Bleed and Lube was not effectively able to kill the well as it has high GOR.

Slickline drift was carried out first to re-confirm the restrictions. Static Bottom Hole Pressure (SBHP) measurement was performed to know the exact reservoir pressure at the moment to calculate the correct brine weight to kill the well. Heavy brine was prepared to overcome the current reservoir pressure (increased because of massive gas injection), 10.5 ppg of Calcium Chloride (increased by 372 psi in 3 years).

3.2 Polymer Plug Operations

To achieve high and better pumping rate and pressure, operation with standard coiled tubing BHA with 1.81” OD-outside diameter (completion maximum restriction 2.2”) was chosen.

Operation started by perforation acid wash with 7.5% HCl and jetted across perforations. No drag or tension drop when passing thru restriction. Acid was flowed back to surface and fluid returns were monitored to ensure acid out. Gas and oil were flared.

Operation continued to kill the well. Coiled tubing placed 1 m above TD and start pumping at 1.5 bpm to kill the well. A-Annulus and tubing return line was lined up to choke manifold. Both are flowed back and flared. Oil and gas are flared, after pumping 278 bbl heavy brine, indication of liquid packed and pumping pressure increased to 3500 psi. Stop pump, release the pressure. Pressure went down to 200 psi and stable. Well killed. Pumped hi-vis at 0.1 and 0.3 bpm. A-Annulus pressure stable at 450 psi, bled pressure slowly, small gas out only and pressure dropped and eventually to zero. Decided to run in CT without pumping to spot the polymer.

Sufficient injectivity shall be obtained prior to pumping the polymer squeeze to ensure sufficient slurry penetration into the formation. A typical injectivity of WHIP below 1000 psi at 1 bpm is required.

Figure 5 shown the well schematic, where all perforations intervals was opened and causing APB because of well integrity issue in the completion.

Injectivity test with heavy brine was performed with good results as tabulated below:

Table 1. Injectivity results prior Polymer Squeeze

Injection Rate (bpm)	WHIP (psi)
0.5	396
0.75	594
1	945

Operation followed with pumping continued with 6 bbl 7% KCl as spacer followed by 12 bbl of polymers, then followed again with 10.5 ppg Calcium Chloride to displace it. Tubing head pressure (THP) was decreased to 0 psi, and A-Annulus at 75 psi with 36/64” choke. Closed in the well. Squeeze the polymer by pumping 0.7 bpm 10.5 ppg Calcium Chloride, able to squeeze 5 bbl polymers to perforation, final THP was 195 psi and CT pressure 1400 psi. Estimated top of polymers 15 m above perforations. Bled off all pressure to 0 psi.

The well was secured, as shown in Figure 5, where all perforations already squeezed with polymers (blue color), with hi-vis as cushions. From operational records, the operation was successfully executed by ensuring good injectivity with perforation acid wash to achieve squeeze pressure below 1000 psi as required by the manufacturer.

3.3 Polymer Plug Results

Figure 6 shown the pressure test graphics of polymer plug. Pressure test performed from tubing (surface pressure test) was carried out with step by step positive test from 500 psi/10 minutes up to 2400 psi/10 minutes showing good indication that the polymer was set and holding as seen in Figure 6 . Followed with 200 psi /10 minutes negative test with good result.

The well has been temporarily suspended for more than seven months, with no pressure build up on tubing and A-Annulus, the well is ready for the workover. Workover was done afterwards without any CT milling operation and packer could be retrieved to surface. Finally, after workover, the well was cleanout with CTU & re-perforated.

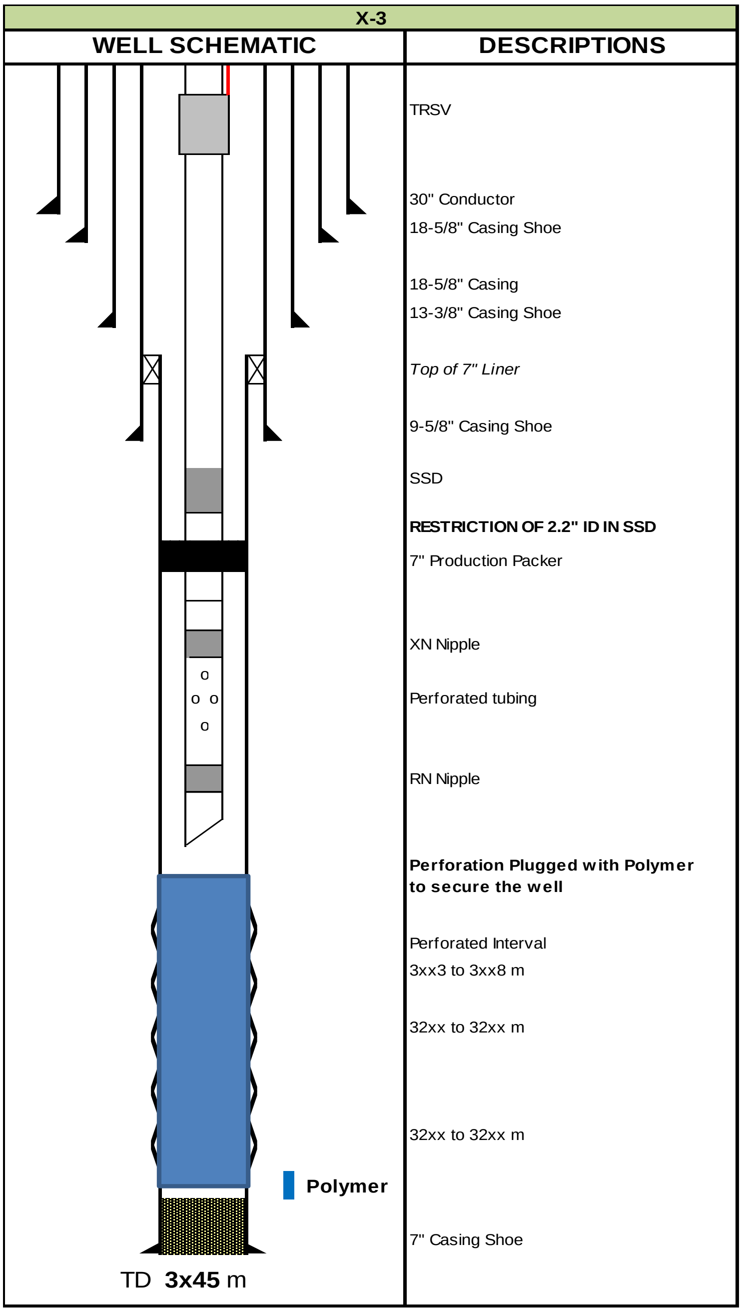


Figure 5. Wellbore schematic after well suspended with polymer plug.

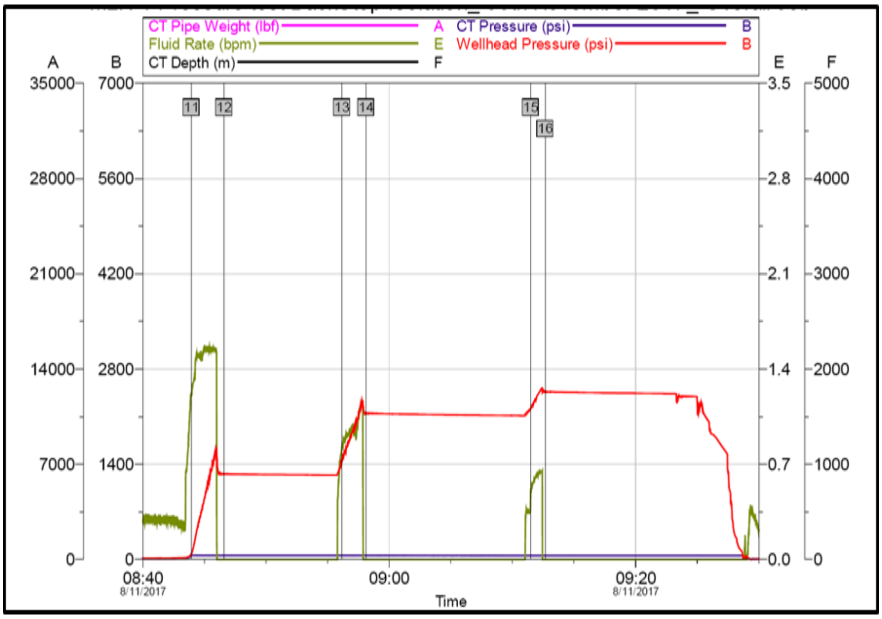


Figure 6. Pressure test result of a polymer plug.

3.4 Discussions

Naser Al-Houti et al., 2017 concluded that polymer squeeze is an effective method for sealing perforation intervals and proved to be an alternate to cement squeeze, hence reducing the milling operation time and cost of operation. Based on the operation evaluation, polymer plug operation could be done safely and stop the gas migration, also securing the well from APB re-occurences. Good injectivity rate should be established prior polymer injection, to ensure sealing of polymer to the opened perforations. Normally injectivity rate below 1000 psi is required.

Further study and field experiments of this polymers should be continued to be tested for various well isolations problems, such as loss circulation isolations, fluid migrations behind pipe, etc.

IV. CONCLUSIONS

Based on the design and operation for this well, proper design in well securing operations is essential especially in a gas injectors field, where static bottom hole pressure will change with time. Polymer plug operation could be done safely and successfully stop the gas migration to surface (until now, there are no gas migration to surface), and secured the well from any re-occurrences of A-Annulus APB.

Sufficient injectivity shall be obtained prior to pumping the polymer squeeze to ensure sufficient slurry penetration into the formation. An injectivity of WHIP below 1000 psi at 1 bpm is required.

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