HTHP Gas Production Casing Cementing

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Abstract

A good cement bond on the production casing of a new wellbore is always the desired result yet until now there hasn't been one paper written that compiles tried and true methods for achieving these results. Nowhere are the consequences for poor cementing of the production casing more important than tight gas HTHP wells. These wells are typically fracture treated and a good bond for zonal isolation of the fracture is critical. Also a micro-annulus becomes not only a production issue yet a well control issue.

Introduction

The following is a compilation of good cementing rules of thumb for HTHP gas production.

1. Drill a gauge hole. Gauge holes are easier to centralize casing in and displace mud ahead of cement.
2. Cement with flowrates as high as possible in turbulent flow. A gauge hole will maximize annular velocities.
3. The purpose being to displace all of the mud ahead of the cement and thus you get all cement and no mud and thus great cement bond. Turbulent flow displaces mud better. As long as the mud, spacer, cement are in increasing hierarchical rheologic order. Rheologic means, density, yield point, and viscosity.
4. The concept is ERODABILITY of the mud. Condition the mud BEFORE running production casing. Stop watching the clock and Days vs. Depth curve. Get the mud rheology right. Flat gels in the mud left in the hole. This means the gel strengths don't increase over time or else the mud will clabber up. The high tech term is Erodability. Clabbered mud has low erodability. Flat get mud has high erodability. Find the expert cement engineer with a reputation for great bond logs. Let him make the recipe.
5. Take extra time to circulate with the casing on bottom. Make sure the mud is still flat rheologically even if it was before running casing it now may be clabbered up again. Treat it all over again. Sure time is money yet the measure of drilling a well really boils down to the cement job. Take the extra time if the mud isn't exactly right and treat it if necessary to match the hierarchical design of the cement job. The mud, spacer, cement must be in hierarchical rheologic order.
6. Get the mud engineer and cement engineer to design a hierarchical cement design. This means the mud ahead of spacer, the spacer, and then the cement all have a certain rheology so that the mud is displaced by the spacer and the spacer by the cement if the fluid ahead of the cement is too viscous the cement channels.
7. Find a cement design expert with a track record of excellent cement bond logs. Let this expert design the cement. Factors might include: thixotropic slurry,

a low Young's modulus slurry, and expansion additives. Have them run the cement job hydraulics and ensure that turbulent flow can be achieved with consideration to ECD's and formation integrity as an upper bound on flowrates.

8. Design the hole and the casing to create an annulus that will have the optimum geometry and annular velocities to create the best cement job.

9. Don't start the cement job until the mud has the right rheology. Repeated for emphasis.

10. Displace the cement with the lightest fluid possible. This will minimize casing OD during cement hardening and allow the cement sheath to harden snugly close to the casing.

11. Make sure the float equipment can hold back the lift pressure of the cement job. Must calculate this pressure.

12. On HTHP wells use latch down high pressure double float equipment to ensure that the high lift pressures can be held.

13. The reason for this is so that the casing can be left open internally and allowed to contract as the cement hardens. If valve on the rig floor on the casing is closed the cement exothermic reaction will build internal pressure, the casing will expand, the cement will harden, the pressure will be bled off leaving a microannulus between the outside of the casing and the cement. This will give a bad cement bond log and perhaps allow fluids to channel.

14. Proper centralizer placement. If you don't know how to calculate this then ask the cement company for an expert. Get this done. All centralizers are different the designer must know this.

15. Get a caliper log on the hole before the cement job. This helps correct cement design and proper centralizer placement. Gauge hole gives best cement bond for two reasons, better centralization and mud displacement.

16. A centralizer that lands across a washout isn't a centralizer. If it doesn't touch the sides of the hole it can't centralize. Hence the importance of the centralizer designs in conjunction with the caliper log and a diligent pre-job assessment of the formation's probable pre-cement state using offsets logs and all available science to predict the hole diameter at each centralizer depth.

17. Reciprocation of the casing has been proven to help in getting more cement to fill in gaps that might be bypassed in many cases. Rotation is also thought to improve cement bonding as well.

18. Hesitation squeezes the last several barrels of cement. This means stop pumping. Allow the cement already in the annulus time to set up a bit. Then pump half the remaining cement and repeat. Static circulation pressure is higher than dynamic if the cement sits a few minutes and begins to dewater. This is believed to form better bond, especially at the shoe area.

19. Sand blasting the casing prior to running it is believed by some to allow cement to bond to the casing better. There is at least some laboratory validity to this seen in test using lab equipment that shows "erodability" increases on equipment that is sandblasted. Also,

sandblasting increases the “rugosity” of the surface of the casing that helps cement adhere to it and it is also noticed that the rugosity creates localized turbulence that adds in mud erosion.

20. Pre-tension the casing beyond the weight that will be landed in the wellhead hanger while the cement is setting up. Many times the production casing is landed in the wellhead with the weight of the string “as cemented”. This is the buoyant weight of the casing string in the cement or cement and fluid above it in the annulus as well as the fluid on the inside of the casing. To get anymore string weight than this without moving the casing, the amount of reactive force from the centralizers as drag will need to be carefully calculated. This can easily be done by obtaining the details of the starting and running forces of the exact type of centralizer and accounting for variances in actual callipered hole sizes to be encountered. This number can be calibrated as soon as the casing reaches bottom before the cement job by picking up off bottom and noting the difference between the pick up and slack off weight and the force required to get the casing moving up the hole. Simply stay below this hook load. This means two things, too much tension will move the pipe, too little will allow the OD of the casing to shrink once the cement sets and the tension is hung off in the casing hanger in the wellhead. Once the heat from the producing well hits the casing it will lose even more tension and contract the OD more perhaps losing the tight cement bond. In HTHP wells this is very difficult to model yet important to. Figure the tension needed to prevent buckling and slack off the weight on the hanger to allow for the OD to expand. There are many papers (SPE) on the subject of cement jobs and erodability. Better Cement Jobs SPE papers include: SPE 23927, 9284, 17441, 107701, 28441, 14135, 26982, 38130, 14197, 3809, 23987, 24571. One famous cement blend: Tail Slurry: Premium H + 35% Silica Flour + 50 lb/sk Hematite + 0.3% Dispersant + 0.4% 1st Fluid Loss + 0.6% 2nd Fluid Loss + 0.5% Anti GFAC additive + 0.4% Synthetic Retarder + 0.2% Retarder (19 ppg; 1.57 cu.ft/sk; 5.27 gal/sk) Spacer: Oil Base Spacer mixed @ 18.5 ppg Displacement: 20 bbls clay fix Water @ 8.4 ppg followed by 10 ppg NaCl brine This response was posted in 2006 by the late Larry Flak, as a post to an SPE drilling engineering technical forum: In our vertical monobore completions in South Texas in HTHP environments (18.1 ppg Hematite oil mud at ~15,000 feet with 350 - 375 F BHT environment) these are the things we typically do: 1. Drill a gauge hole. This is likely the most important factor. As we are limited in circulation rates with 5-1/2" x 4-1/2" monobores (9-5/8" 53.5# to 11,500 with 7-5/8" 29.7 liner 11,300 to 12,400, 6-3/4" hole) or we initiate ballooning. 2. One bow spring centralizer in middle of joint (we use 4-1/2" 15.1# Q-125 casing to near top of 7-5/8" liner then XO to 5-1/2" 26# T-95 (0-8000) and P- 110 casing (8000-11400). 3. Sand blast all 4-1/2" casing (much better cement bond to pipe seen in bond logs) 4. We use the

following cement: Tail Slurry: Premium H + 35% Silica Flour + 50 lb/sk Hematite + 0.3% Dispersent + 0.4% 1st Fluid Loss + 0.6% 2nd Fluid Loss + 0.5% Anti GFAC additive + 0.4% Synthetic Retarder + 0.2% Retarder (19 ppg; 1.57 cu.ft/sk; 5.27 gal/sk) Spacer: Oil Base Spacer mixed @ 18.5 ppg Displacement: 20 bbls clay fix Water @ 8.4 ppg followed by 10 ppg NaCl brine 5. Carefully model ECD and limit displacement rate as required to keep wellbore from breaking down. Typically cementing at 3 BPM. 6. Reciprocate casing through the job till plug bumps (we use top and bottom plugs). 7. We use 10,000 psi HTHP float equipment and displace cement with 10 ppg brine with clay fix water ahead of brine. We do not want brine to contact cement. Once plug is bumped with ~8,000 psi, we bleed off the internal pressure to zero, close the annular BOP and WOC. 8. We multi-zone stage frac from 13,000 to 14,700 with up to 4 zones and 4 fracs comingled. Production is up the monobore. SITP is around 11,000 psi limited by cross-flow during shut-in. 9. Total cost of wells is around $5,000,000. Wells cum 6 to 12 BCF. We get perfect bond! 1. Mud properties Condition the mud prior to running casing. Looking to get mud to a condition that will allow it to be moved by the cement that doesn't channel yet displaces the mud ahead of the cement slurry completely. If I did the math right, your mud weight is 12.0 ppg. This is typical of almost every Gulf Coast Intermediate casing job. I hope this getssomeone with more cement and mud property expertise involved yet I would imagine that lowering the viscosity and fluid loss of the mud would be a great start. Gel Strength should be minimized I would imagine. This shouldn't be too costly. The wellbore is very important. If washed out, the best of actions after drilling might not have a chance of success. Best production cement insurance is a "GAUGE HOLE" with all of these other methods. > 2. Cement slurry design and cement job operation. The cement slurry should be at least 4 ppg over the mud weight so this shouldn't be difficult to achieve depending on how high up the cement is needed (how high the upper HC or other problem zone is). Also try Sodium Silicate in the pre flush. It coats the permeable zones and makes the cement flash set as it touches it. This coats the zone and prevents losses. Try rigid blade centralizers across the pay zones (w/20-30 degrees angle need stabilization). Hesitate squeeze the job. Check w/your cement company, yet stop 30 bbls (or so) short of the complete displacement wait couple of minutes and then pump 10 bbls; repeat two more times. Worst thing that can happen is to get couple of hundred feet of cement left inside (drills quick). This tends to fill channels especially if combined with reciprocation and rotation (try with a casing running tool than can rotate and pump cement) Also, micro annuli form if there is pressure held while the cement is setting up. Use float equipment, with redundant valves, and appropriate pressure ratings to allow the cement displacement with a fluid much less than the previous mud weight. Try using fresh water to displace the cement plug. Once the plug is bumped and latches closed bleed the pressure off making sure that the valves hold. This will allow the cement to 'contract' around the casing as the casing itself decreases diameter. Once the pressures go up the pipe will fit like a glove within the cement job. > 3. Casing handling practices during /prior to cement job. Rotate pipe (need special running cementing tools), reciprocate, use up jet float equipment. Pay attention to the pressures used while running a CBL. Pipe expands under pressure and contracts under tension. How much tension to pull up on the pipe is a different subject. Tensioning the pipe while the cement sets will have an effect. The trick is to tension the pipe properly and not create a 'microannulus'. My belief is minimize internal pressure and get the tension in the pipe while cement sets up. Depending on how high the cement is calculation of the casing setting weight is very difficult yet vital especially in hot hole regions. Unfortunately, water encroaches at precisely the same time as the reservoir, and thus internal casing pressure, decreases, thus the casing contracts and there is a greater chance for the casing/cement microannulus to form. Drill the hole gauge. The best way is oil based mud or highly inhibitive and low fluid loss systems. With a gauge hole the other methods work to make a 'state of the art' completion. Hope this starts a discussion with smarter and more experienced people that frequent this chat.