Wellhead Isolation Techniques

Objective – report typical and non-typical methods of isolating wellheads for repairs or service.

Techniques

Normal Plug Isolation

Plugs and profiles should be considered where they are an option.

Inflatable Packer Isolation

Inflatable technology is normally viewed as an effective method for isolation, but the presence of large amounts of acid gas will cause rapid deterioration of the exposed stainless steel strap used in the flexible body covering of most inflatables. The strap is 301 stainless and is very susceptible to damage from cracking in sulfide environments. If the packer is set in gas, time of strap destruction may be measured in minutes. The high stress state of the inflatable makes this corrosion problem worse. The cracking can be lessened if the packer can be set in liquid. If you cannot (as indicated), put liquid on the formation, then an alternate for stainless strapping must be used. A 1018 steel strapping substitute is suggested. The drawback of the 1018 steel is that the inflation pressure maximum of a packer set in 7” casing, would have to be reduced from the 2200 psi typical for the SS-301 strap construction to about 1000 psi for the 1018 strap construction. Since packer holding ability is directly tied to inflation pressure, the change in materials will lessen the holding capability. A packer set in gas would have about an 80% chance of retrievable through the tubing because of gas permeation and expansion of the rubber.

If the packer could be set in a liquid, either water or condensate, the effect of the H2S gas would be significantly lessened and packer life could be extended to several hours. Packers set in liquid also be easier to remove because of less gas permeation of the rubber (less swelling). Retrievable reliability would increase to about 90%. A second method of sweeping sour gas from the wellbore would be to displace the H_2S with nitrogen gas. This is evidently a new idea for packer setting in sour environment: no idea is advanced on its reliability.

Double inflatable packers are not suggested due to removal problems. If a single packer cannot be deflated, a prong (an “icepick” 3 feet long) can be used to puncture the bladder and the unit can be pushed to bottom. Retrieval of a packer deflated in this manner is difficult due to structural damage. If inflatable packers are stacked and the top packer cannot be deflated and removed, then access to, and removal, of the bottom packer is extremely difficult.

If an inflatable packer is used in the sour environment, 50 to 100 ft of silica flour and water is suggested as a safety cap. The silica flour can be removed by nitrogen cleanout. The silica flour plug will likely stay in place even if the plug leaks. The silica flour is useful as a fluid loss control material if a leak develops and the flow is from top to bottom.

Snubbing

A snubbing workover to remove the tubing and set a full-bore packer or plug can be done with a hydraulic snubber or a coiled tubing unit. A lubricator with sufficient length for packer and running or pulling tool is required for installation and removal of the packer. Snubbing force depends on the area of the tubing used to run the packer and the wellhead pressure. Since a second barrier is required, a second type of plug, a kill weight column of fluid (may be spotted above a deep set plug, or a downhole valve will be needed.

H_2S - Experience with snubbers at the low surface pressures in Whitney Canyon is plentiful and successful, but H_2S complicates the workover through necessity for H_2S corrosion resistant materials of the surface pressure control equipment and the problems of gas permeation of rubbers in the BOP stack. In a live well, coiled tubing job on a sour gas well in Canada, control of the well was lost after a CT stuffing box element failed and caused a sudden surface pressure loss. Following the rapid depressuring, attempts to regain control by closing rams; first, in the CT BOP; and finally in the drilling BOP, failed. The cause of failure was explosive decompression of the gas trapped in the rubber seal surfaces. Gas had permeated the BOP ram face rubber in both BOP sets over the time of the workover (reported as nearly 2 weeks). The sudden pressure loss caused explosively decompression of the gas in the rubber seal, and the exiting gas shredding the rubber face on the pipe and blind rams; destroying seal capacity. The well had to be fluid killed to regain control. Inspection of the ram rubber seals after any extended live gas well work is needed. Slow depressurization is required to allow gas to escape and to preserve rubber surfaces and seals, especially when the elastomer materials have been exposed to gas for long periods (usually days).

Tree Saver

Isolation of parts of the wellhead may be achieved with a tree saver (device used in isolating trees during high pressure fracturing). Insert and inflate cups then dissemble bonnet of straddled valves and replace the components. (This will not work for spool and flange replacement.) Since this is only a single barrier, it must be used with a kill weight fluid column or plug set in the tubing.

Freezing

Wellhead freezing is a non-routine intervention method that offers very good potential, both because of simplicity and general reliability. The process has been used on both high and low pressure wells. References found in multi-well use in very high H_2S wells (Exxon) in the Florida/Mobile Bay areas. An ice plug 2 to 5' feet thick has been demonstrated to hold in excess of 10,000 psi (pipe burst before plug released).

For freezing, two conditions are must be met:

1. no gas can be present in area to be frozen; and
2. liquid in the wellhead must be static prior to starting the free process.

To achieve this, a freeze medium is used to purge the wellhead and stop fluid movement.

1. Start with a water based slurry blended at 5-1/2 sacks of Wyoming bentonite per 7 barrels of fresh water. The slurry must be fully sheared and stable in the blender tub. This mixture is injected at as high a pressure as possible. The mixture will flow much the same as soft ice cream. The mixture "oozes" into the tree and displaces the wellhead contents to 300 to 400 feet below the wellhead. The mixture is so thick that it is self packing - true plug flow. (comment: The master valve may be closed part way (throttling) to assist the displacement process – throttling with the master valve is normally prohibited.)
2. After slurry injection, the ice bucket is placed around the bottom flange of the bottom master valve. Pack the bucket with dry ice (cover the wellhead with the ice): the wellhead is allowed to freeze.
3. Freezing time takes 2 hours per inch of steel structural diameter (not id). For a 4-1/2" wellhead (nominal 6" structure OD), you'd need about 12 hours of time before it is frozen.
4. Check for frost lines above (definitely) and below (probably) the bucket. If there is no frost line, it hasn't frozen.
5. After freezing, do a negative test in 500 psi increments to atmospheric, then do a positive test to the limit of the valve. If both tests OK, dissemble above master and replace the valves in the tree. The flange bolts may be difficult to loosen when cold and contracted.

Alternate freeze methods involve liquid nitrogen as the freeze medium. The advantage of liquid nitrogen is that the well can be frozen several feet below ground level (a cellar may increase ease of freeze application. The disadvantage is that steel becomes brittle at liquid nitrogen temperatures and would need to be protected from direct application of the -325°F fluid. Much less is known about the freezing mechanism with liquid nitrogen.

Resources

This freeze method comes from Cudd Pressure Control. Eddie Goodman of Cudd in Lafayette, Louisiana (318) 989 8495 is an experienced resource.