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EXPERIMENTAL INJECTION SET-UPS FOR DOWNHOLE CHEMICAL DOSING

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ABSTRACT

Hollow sucker rods have been substituted for the conventional capillary tubing as the means for conveyance of calcite inhibitor solution in APO-1D, a production well in Mindanao Geothermal Production Field (MGPF), Philippines. Flow control and prevention of chemical flashing inside the 24-mm rod are accomplished with the use of an integrated check valve-and-dispersion-ports mechanism at the end of the rod.

Despite the calculated feasibility of the set-up, actual injection ran through technical difficulties. Despite controls over unwanted boiling of the polyacrylate inhibitor chemical in the injection string, it appears that this tandem will never achieve success due to many more mismatches between them, and modifications would be very expensive. Testing a different chemical such as a polymalaete acid is recommended for future testing.

Another injection set-up using the conventional ¼" OD stainless steel capillary tubing and the same polyacrylate inhibitor solution has been successfully tested in an adjacent production well, SP-4D. Problems earlier encountered and raised by other geothermal field operators have been addressed and modifications on the older systems applied.

1. INTRODUCTION

Early development of the downhole delivery system for calcite scales inhibitor solution made use of the conventional ¼" OD capillary tubing. Benoit (1990), Lovekin (1990) and Robson et al (1990) describe the successful use of this set-up in several production wells in Dixie Valley geothermal field, Coso geothermal field, and Kawerau geothermal field, respectively. They also discussed problems encountered both in the downhole and surface equipment, but there is a general agreement that much of the difficulty lies in designing and operating the downhole chemical injection system which would be free from all problems they previously encountered. Some of those problems are plugging of the tubing with debris, and in some cases with the inhibitor chemical, mechanical failure of the tubing and cases of the tubing being blown up and out of the hole.

The same authors have also brought up improvement in their respective downhole systems, all of which are aimed at protecting the capillary tubing. Coso is now into the concentric tubing design wherein the ¼" stainless steel capillary tubing is run inside a 1 ¼" carbon steel coiled tubing. Dixie Valley makes use of a "hang-down" string to strap the capillary tubing. Both systems are claimed to have far greater use than just scales inhibition. The hang-down string and the coiled tubing may be used to pump nitrogen or air through to stimulate the well by gas lifting. Both systems are now being tested for continuous downhole measurement of temperature and pressure while the well is undergoing chemical injection and even stimulation.

There are also reports that an armoured tubing system has been successfully tried and now used in New Zealand for downhole scales inhibition.

In this paper, the authors illustrate PNOC-EDC's efforts to experiment on alternative methods and improve on conventional means of delivering the inhibitor solution to target depths using readily available materials. Two differing systems are discussed, namely, the sucker rod system and the conventional capillary tubing system.

2. GENERAL EQUIPMENT SET-UP

Ramos-Candelaria, et. al. (2000) describes in detail the equipment set-up employed in MGPF. The pump system is located in a pad where 3 production wells, including APO-1D and SP-4D, will eventually share the same set-up. Essentially, it consists of an electric dosing pump (with a back-up unit), chemical solution tanks for mixing and feeding, a mixing/recirculating pump, and a downhole injection system installed through the wellhead.

The inhibitor chemical, which is an aqueous solution of an acrylate polymer (Ramos-Candelaria, et al., 2000), is conveyed to the wellhead through a high-pressure chemical hose or a 3/8" OD stainless capillary tubing.

Each chemical dosing pump is capable of delivering a maximum of 26 liters per hour. Maximum working pressure of the pump is 1500 psig at which pressure flow is reduced to almost zero. Downstream surface pipes and fittings are rated 2500 psig, while the chemical hose is rated 3000 psig. Upstream of the dosing pump, fittings and pipes are rated 150 psig. All surface process components in contact with the chemical inhibitor are stainless steel 316, except for the chemical tanks, which are of PVC construction. The pump skid is also made of stainless angle bars for corrosion resistance in a generally corrosive geothermal environment.

3. SUCKER ROD INJECTION SYSTEM

The downhole injection system for well APO-1D consists of 951 meters of the 34-mm OD sucker rod, a downhole check valve with dispersion ports at the bottom, an injector head assembly, and an annular pressure pack-off assembly or stuffing box (Figure 1).

The sucker rod looks much like a small drillpipe, with 50-mm tool joints for handling during run-in and connection. It has metal-to-metal seals at connections, and a secondary seal consisting of two rubber o-rings at each connection.

The downhole check valve (Figure 2) employed in the APO-1D set-up was initially intended to prevent gas kicks during run-in of the rods in the hole and backflow of geothermal fluid to the surface pipes during injection upsets. Later discussions, however, will reveal a more important use of the check valve vis-à-vis the properties of the inhibitor chemical used in the trials.

The injector head assembly (Figure 3) contains fittings for gauges, check valve, isolation and bleed valves. The check valve in this assembly is a flapper type valve and is intended to prevent any back flow of the inhibitor solution to the pumping system during emergency situations such as power failures and surface line repairs.

The annular pressure pack-off assembly (Figure 4) is a modified sucker rod stuffing box commonly used in oil wells. Modifications incorporate the replacement of rubber o-rings with high-temperature synthetic materials and the use of braided Teflon as packing element.

3.1 DESIGN CONSIDERATIONS

In designing the set-up, the following criteria were considered:

1. The acrylate polymer inhibitor solution must not be allowed to flash inside the sucker rod as this will induce precipitation of a substance which in turn will cause blockage and injection failure. As the average wellhead flowing temperature is about 210°C, corresponding to a saturation pressure of 1.91 MPa (277 psi), it was estimated that an injection pressure about twice the saturation at the wellhead is sufficient to prevent flashing of the inhibitor chemical inside the injection tubing.
2. The check valve spring and the wellbore pressure at the injection depth must support the liquid hydrostatic inside the sucker rod in both cold and hot conditions in order to maintain a liquid-filled injection line.
3. Hot liquid head inside the rod must also be maintained to reduce pumping pressure.

The specified maximum pump rate of 26 liters per hour effectively ensures that viscosity of the inhibitor solution and fluid velocity inside the 24-mm ID pipe are not a factor in the design. Therefore, pump capacity was matched only with the measured wellbore pressures, fluid head and check valve crack pressure.

Determining the check valve crack pressure involves calibration of the check valve spring at various regulator screw settings, both for cold atmospheric condition and at the expected injection-depth temperature of 235°C. Hot-calibration was done inside an oil calibration bath. Figure 5 shows the calibration plot for one of the check valve springs used in APO-1D. In this particular calibration, it was determined that the suitable hot crack pressure of about 940 psig requires setting a cold crack pressure of 1050 psig. Thus, surface flow tests involving the pumps and surface piping were done to re-set the valve crack pressure at 1050 psig on the surface.

Running the sucker rods into APO-1D required quenching the well, which has a natural shut-in gas pressure of about 4.5 MPag and thus the ability to self-discharge. A steel platform from used drillpipes and sheet metals was built on top of the well for the run-in operation (Figure 1), and a crane was used for handling the rods. This set-up eliminated the need for a rig during the run-in.

Additional downhole injection tests using water were done while the well was still quenched and during the heat-up period. Inhibitor pumping is then initiated 48 hours before flowing the well to ensure that the inhibitor solution had already reached the chemical dispersion ports before flashing of the wellbore fluid ensued (Ramos-Candelaria, et al., 2000).

3.2 RESULTS

The first installation worked for only a week after massive leaks developed around the stuffing box. Pump pressures also became erratic when quenching stopped, building up to as high as 1000 psig and dropping to 0 at times. Bleeding the sucker rods resulted in the discharge of high-chloride two-phase fluid at one time, confirming earlier suspicion that the downhole check valve was malfunctioning. The string was subsequently pulled out for inspection and re-calibration of the check valve.

Modifications in the system were then implemented:

1. To arrest the leaks at the stuffing box, by replacing the rubber o-rings with high-temperature synthetic materials and increasing the surface area of the string that is packed with braided Teflon.
2. To prevent apparent sticking of the check valve guide shaft, by enlarging the valve seat and neck and isolating the guide shaft and spring from the inhibitor flow path.
3. To prevent boiling of the fluid inside the rods, by increasing the crack pressure of the check valve from 800 to 1050 psig.

The final installation of the sucker rod system in APO-1D resulted in a 50-day injection trial. Injection pressures ranged from 100 to 800 psig until on the 30th day of injection it climbed to as high as 1000 psig. Pump rate averaged 10 liters per hour for an effective dosing of 5 ppm of inhibitor in the total massflow. The actual pump pressures contrast sharply with the expected pressures in the system (Table 1) and those recorded in the initial set-up. Eventually, the experiment was terminated when pump pressures were already approaching pump limits.

The string was pulled out again, and the last 7 meters of the bottom joint to the check valve found to be clogged with a tar-like material which was later analyzed to be composed of about 80% acrylate polymer chemical, 10% clay minerals and 5% corrosion products. The clay minerals must have been impurities from the make-up water, while the corrosion products must have come from the reaction of oxygenated make-up water with the carbon steel sucker rod. The valve neck and seat were also found filled with the same deposit. At this point it was definite that the system had no chance of working due to the following:

1. The tendency of the inhibitor chemical to crystallize and form a tar-like substance at extended exposures to high temperature requires a much smaller tubing ID than the sucker rods' 24-mm ID for a short residence time.
2. The small dosing rate (actual maximum of 20 liters per hour) is simply too little for the stored liquid volume in the 951-m sucker rods.
3. The use of a high tensile spring in the check valve to support the liquid hydrostatic inside the sucker rod at all anticipated conditions led the check valve to function like a relief valve. Thus, instead of promoting a continuous flow the valve would initially support the hydrostatic and additional pressures from the pump before abruptly opening as its crack pressure is reached. This apparently led to the pressure build-ups and fall-offs during the injection trial.
4. The carbon steel sucker rod is susceptible to the corrosive nature of the inhibitor chemical so that eventually the rod would become prone to mechanical failure.
5. Set-up is too demanding, requiring shut-in of the well, and quenching if the well has shut-in wellhead pressures.

3.3 POSSIBLE IMPROVEMENT

Despite its being unsuitable for the calcite inhibition application in tandem with an acrylate polymer inhibitor, the sucker rod system may still be used in similar applications using a less volatile and non-corrosive inhibitor, or in larger-volume downhole-injection applications such as sodium hydroxide treatment of acidic well discharges. The additional expense in shifting to a sucker rod or similar pipe which are corrosion resistant will have to be closely studied vis-à-vis the overall economics of individual well installation.

The excellent mechanical properties of the sucker rod offer opportunity for continuous downhole measurement simultaneous with inhibition, similar to a set-up developed and tested by Benoit, et al. (1999). The difference between the two may be the absence of the capillary tubing in the sucker rod system only if a non-acrylate polymer inhibitor is used.

It may also be the ideal set-up for wells which always require gas or air lifting to discharge as the sucker rod may be used for both chemical injection and stimulation, as in Oxbow's experience (Benoit, 1990). In this type of wells, the downhole check valve may simply be replaced with a nozzle assembly of suitable size.

4. CAPILLARY TUBING SYSTEM

The capillary tubing system employed in well SP-4D (Figure 6) is no different in general from conventional installations (Benoit, 1990; Lovekin, 1990; Robson et al., 1990). Unlike in the sucker rod system, however, flow inside the ¼" OD capillary tubing involves massive frictional pressure drops, almost guaranteeing that there will always be positive pump pressures on the surface. Thus, the downhole check valve was eliminated and only a ball-type one installed downstream of the pumps. System pressures as calculated are summarised in Table 2. Calculation of the friction factor is based on Churchill (1977), allowing for a single equation for all fluid flow regimes.

4.1 SINKER BAR WEIGHT

An added design criterion in this case is the use of an appropriately weighted sinker bar, which should prevent floating of the line while limiting mechanical stress on the tubing. For this requirement, shear forces on the exposed tubing and sinker bar, together with calculated buoyancy of the system have been equated with the total weight of the injection system to derive the optimum sinker bar weight. Calculations were performed for the maximum-recorded total massflow of 60 kg/s and a minimum of 40 kg/s, with a resulting sinker bar weight of 72 kg and 54 kg, respectively. The calculations assume that the sinker bar is always submerged in the liquid column, an assumption that is borne out of the requirement for injection of the inhibitor chemical below the flash point in the hole for an effective treatment.

Upward adjustment on the resulting sinker bar weight is also introduced based on incremental changes in line weights during earlier production logs in the well. It is assumed that the decrease in line weight at higher flows approximates the additional upward drag on the tubing and sinker bar that has to be overcome by the weight of the sinker bar. This allows for maximising the well discharge without the danger of floating the injection system.

4.2 OTHER FACTORS

Available tubing length was only 1100 m, with only 950 m at most which could be run downhole. SP-4D also has a metallic obstruction at 825 m, limiting the setting depth of the injector to 820 m for safety reasons. These conflict with the recorded flash point of the well which ranges from 540 m at maximum throttled condition (1.5 MPag wellhead pressure) to as deep as 1250 m at fullbore discharge (0.8 MPag wellhead pressure). Wellbore simulations predicted that flowing the well at wellhead pressures higher than 1.2 MPag will result in flash points shallower than 800 m. Thus the injector was set at 815 m allowing for 15-m submergence of the injector below flash point.

Also, buoyancy does produce a significant upward force on the sinker bar. Thus, its OD is minimised to 2 1/4” to reduce the effect of buoyancy on the downhole set-up. This, however, resulted in a longer sinker bar, which at the same time is limited by the length of the lubricator spool. Using a sectionalised hollow carbon steel pipe for the sinker bar body and filling it with lead for the additional weight (Figure 7) solved the problem.

A 3” stinger pipe (Figure 6) is set above the master valve to prevent the tubing from being sucked into the production tee. Its bottom is lined with a Teflon tube, which is screwed onto the stinger pipe body. The Teflon tube prevents metal-to-metal contact between the capillary tubing and the stinger pipe. Its 2.5” ID allows passage of the injector and sinker bars, thus making it possible to increase the weight and length of the sinker bar without extending the lubricator pipe.

To prevent water impurities from entering the system, as was experienced in APO-1D, in-line filters upstream of the feed water tank and between the mixing/chemical tank and dosing pump were installed.

4.3 RESULTS

The capillary tubing was run after the well was temporarily cut off from the production line. A weight indicator was left attached to the bottom sheave for continuous monitoring of the line weight. With the well flowing about 40 kg/s (total mass flow) at 1.3 MPag, the line weight has remained steady at about 45-50 kg. This assures the authors of a sufficient control over possible line floating with an extra pull on the line at discharging condition.

SP-4D was estimated to have about 6-7 MWe capacity on full bore, with a decline rate of about 0.6 MWe/month without inhibition. As of this writing, it has been on commercial production at 3 MWe for more than two months since placement of the capillary tubing system. To this point, no signs of any decline in capacity have been recorded. Chemical analysis of water samples from the two-phase lines also shows that calcium levels have remained unchanged and in equilibrium with reservoir calcium concentration since the start of inhibition (Ramos-Candelaria, pers. comm.).

The only problem encountered in the SP-4D set-up is the formation of salts (mostly sodium and potassium) in the pack-off assembly and the wellhead. This prevented the pullout of the tubing for inspection and maintenance one month after it was run in. The salts formed apparently due to evaporation of the leaking geothermal fluid through the pack-off.

Ramos-Candelaria, et al. (2000) discusses in more detail the chemistry side of the successful calcite scales inhibition trials in SP-4D.

5. SUMMARY AND CONCLUSION

The calcite scales inhibition trials in Mindanao Geothermal Production Field produced the following results:

1. Use of the carbon steel sucker rods for pumping the acrylate polymer inhibitor chemical is not feasible. It is however expected that a different inhibitor type, which does not precipitate on prolonged exposure at high temperatures, may work with the sucker rod system.
2. Given appropriate protection from downhole abrasion and with sufficient weight to counter fluid velocities and buoyancy the stainless capillary tubing system still appears to be the most cost-effective means of inhibitor chemical conveyance downhole. This is provided casing conditions will allow.

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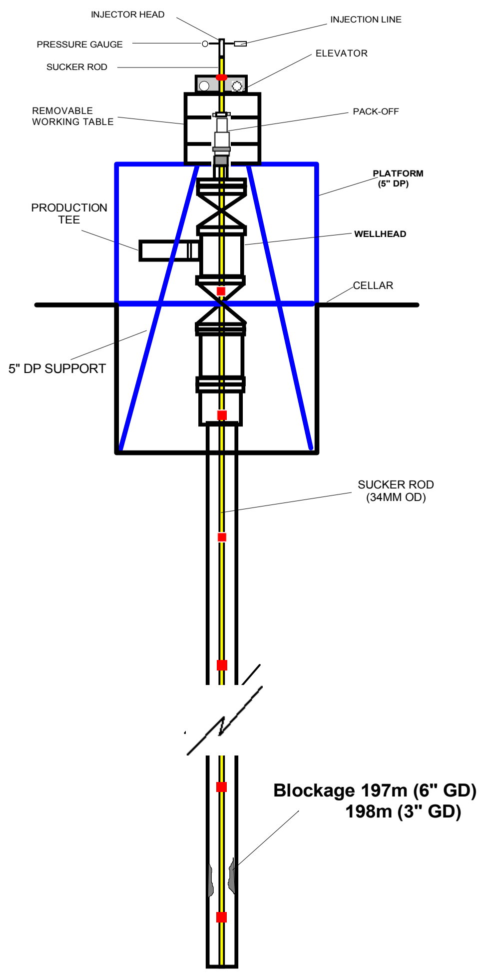

Figure 1. Sucker rod injection set-up at well APO-1D

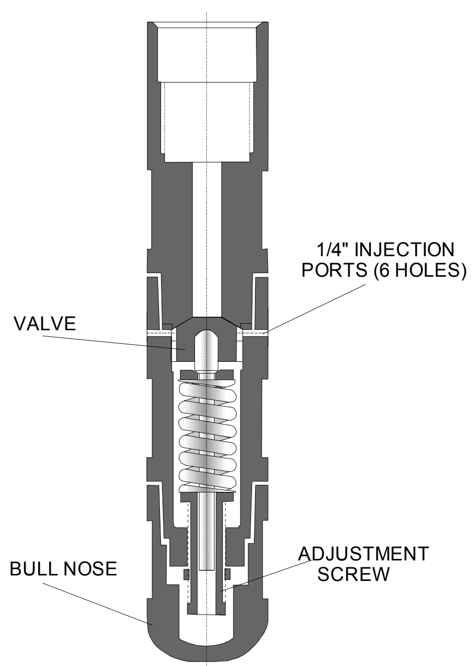

Figure 2. Downhole check valve used in the sucker rod set-up of well APO-1D

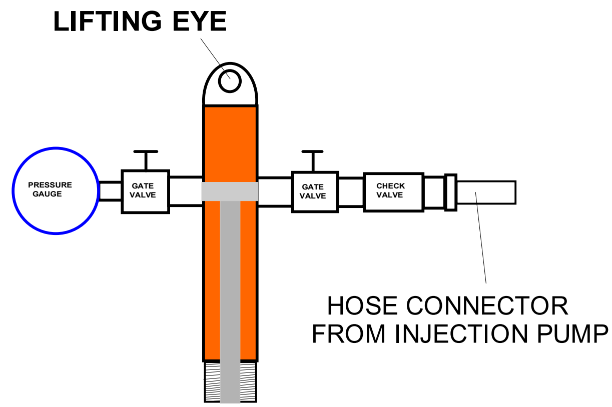

Figure 3. Injector head assembly of APO-1D sucker rod injection system.

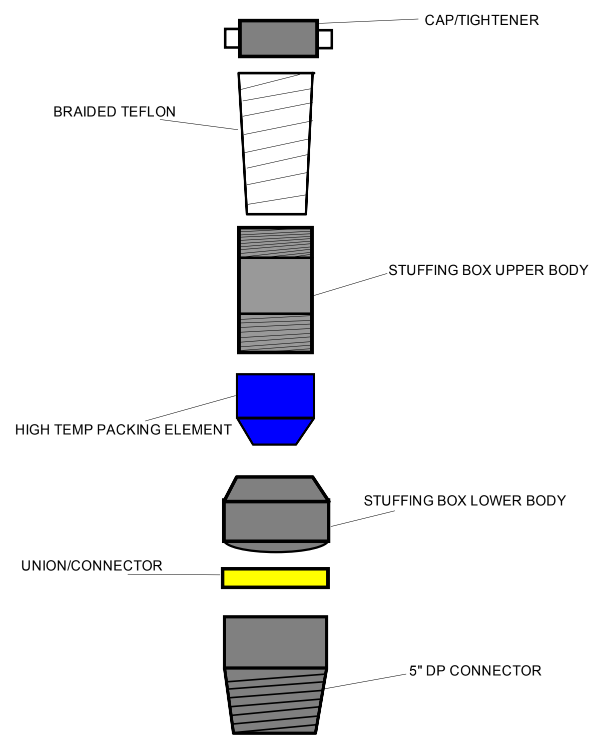

Figure 4. Pack-off assembly for the APO-1D sucker rod set-up

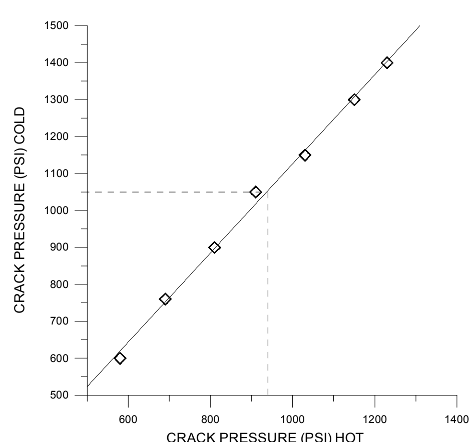

Figure 5. Calibration plot for downhole check valve.

Table 1. System pressures in the APO-1D sucker rod set-up.

Condition	P_{liq}	P_{950}	P_{cv}	P_{inj} (theo)
Cold (shut)	1340	798	1050	508
Heat-up	1134	747	940	553
Discharging	1151	609	940	398

where: P_{inj} (theo) = $P_{950} + P_{cv} - P_{liq}$
P_{inj} (theo) = Injection pump pressure, psig
P_{950} = Wellbore pressure at injection depth, psig
P_{cv} = Check valve crack pressure, psig
P_{liq} = Liquid head inside sucker rod, psig

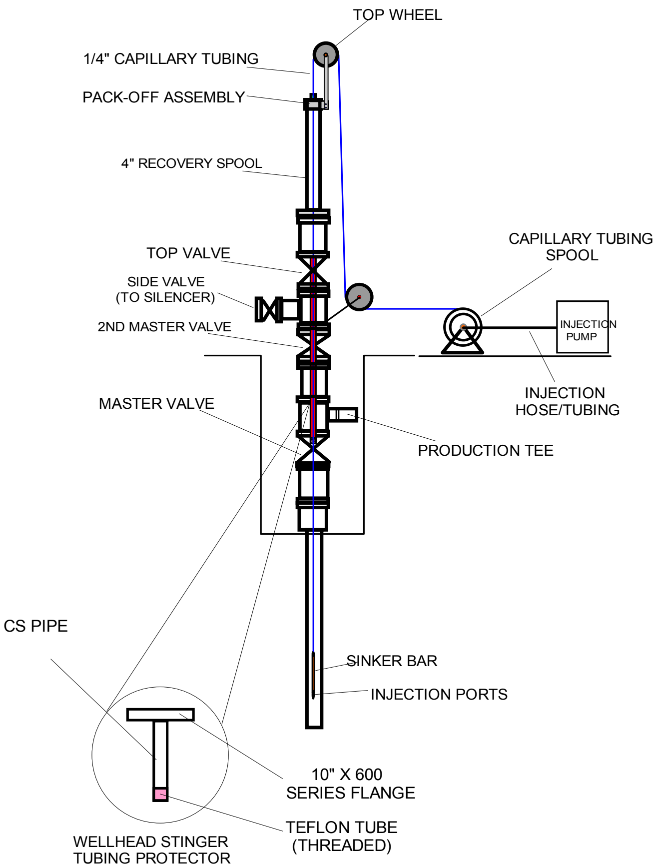

Figure 6. Set-up schematics of the SP-4D capillary tubing system.

Table 2. SP-4D calculated system pressures (psig) at two discharge conditions

	Flashpoint, mMD	P_w	dp_f(corr.)	dp_g	dp_{total}	P_{inj}(theo)	P_{inj}(actual)
1	603	537	-698	997	299	238	180-220
2	800	464	-698	997	299	165	-

Notes:
Injection at 740 mVD (815mMD)
Condition 1 @ 13.3 kscg OWHP and 44 kg/s massflow.
Condition 2 @ 11.0 kscg OWHP and 57 kg/s massflow.

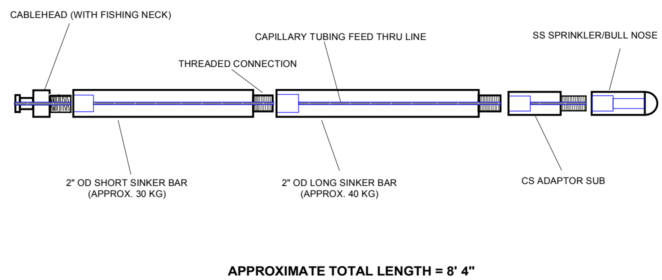

Figure 7. Sinker bars used in well SP-4D calcite inhibition system.