CORRECT FLOWBACK PROCEDURE - A KEY TO SUCCESSFUL FOAM STIMULATION

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ABSTRACT

The elements of a successfully planned and executed foam stimulation treatment have characteristically included surface and bottom-hole foam quality calculations, foam rheology, foam structure, surfactant and polymer requirements, pressure volume and temperature considerations, proppant transport, and fluid and nitrogen rates.

Often taken for granted is the importance and advantages of foam flowback after the treatment to obtain maximum load recoveries with minimum or no proppant flowback into the wellbore or to the surface.

A carefully planned and successfully used procedure is presented to allow more quantitative and precise control of foam flowback after a treatment is completed. Considerations for proper shut-in time, flowback technique, return fluid character, pressures, rates, closure stress criteria and formation damage will be made. The use of adjustable versus positive choke assemblies is discussed and advantages and procedures for the use of both are offered. Procedures for foam flowback from shallow, moderately deep and deep well treatments are recommended with considerations for bauxite and and propping materials.

Careful attention to the surface equipment preparation will result in obtaining maximum load recovery, with minimum proppant fill and/or flowback. This will allow the operator to realize the full benefits from the foam treatment sooner.

Flowback procedures can significantly affect the resultant positioning of proppant in the packed fracture and subsequently the sustained productivity of the well. The importance of determining the closure stress requirement to enable adequate proppant entrapment in the fracture is presented.

An equally important factor is the cooperation of the service company and operator in designing, and implementing these procedures.

Understanding the consequences of not following these procedures is also important, and may offer clues as to why a foam stimulation job's results may not have been as good as anticipated. Key factors for determining that these procedures were not followed will be reviewed.

INTRODUCTION

Foamed stimulation, particularly foam fracturing has been practiced for over ten years, and in that time the variables by which foam is controlled during the application of a treatment are widely published. One post treatment variable that has received little attention is the importance of following a correct flowback procedure after foam fracturing treatments.

Several advantages can be realized by properly timing and performing the flowback of a well after foam fracturing or other types of foamed stimulation. The advantages relate directly to the recovery of the treatment fluid volume which is certainly beneficial in the case where a "fluid-sensitive" reservoir has been treated. The obvious advantages of recovering the treatment load can only be realized by following certain controlled procedures within a specified time after the treatment has been completed and shut-in. Correct observance of these procedures may even allow the majority of the treatment to be recovered without the services of a swabbing unit. Ultimately the benefit of proper flowback will be improved and more sustained productivity.

Another consideration after a foam treatment is the possibility for proppant flowback into the wellbore, or to the surface, sometimes causing damage to wellhead tubulars, valves, chokes, flow lines, etc. If certain procedures for flowback are followed, proppant flowback into the wellbore or to the surface can be reduced or eliminated.

If foam treatments are flowed back too rapidly it is even possible that casing collapse can occur due to the tremendous vacuum effect created.

Proper procedure includes readiness to perform and stay with flowback, providing the necessary wellhead equipment configuration, proper pressure monitoring, proper flow control equipment, and adequate safety practices.

The mechanism for breaking the foam to allow flowback, and the sequence in which it occurs after a job are equally important factors. Overtreatment with foaming surfactants or foam stabilizer additives can cause foams to not expand and break properly which in turn can be responsible for poor treatment fluid recovery due to foam blockage in the reservoir, and/or recovery of proppant in large quantities after the treatment. Less than optimum amounts of foaming surfactants or foam stabilizing agents may prevent the job from being performed properly and lead to premature treatment screenout.

Finally the ability to analyze shut-in pressure information to determine the closure stress from final bottom hole treating pressure data, and reservoir pressure emphasizes the importance of properly planning the treatment flowback procedure. Treatment shut-in time is a critical element, therefore, in maximizing the effectiveness of foam fracturing, and should not be overlooked when planning a job.

When all the correct elements of a foam stimulation treatment are designed and implemented, the foam treatment is complete. Bottom-hole and surface treatment parameters are important, but the key to a more successful foam stimulation is in the correct flowback procedure which ultimately allows quicker realization of well productivity with better, sustained results due to recovery of the maximum load possible, and the achievement of an optimum fracture closure.

MECHANISM FOR FOAMS BREAKING

In order for the flowback procedure to be successful after a foam fracturing treatment the stable foam bubbles must break to allow the reduction of proppant suspending, effective viscosity.

It should be noted that Bikerman's example is proof that foams used for carrying solid particles are actually three phase foams with the solid particles suspended in a gas-liquid boundary by surface tension. (See Figure 1). Particles attached to a bubble as indicated in Figure 1 will prevent bubble coalescence and, in this manner, enhance foam stability.(1) Since proppants are this third phase, they should not be considered as a portion of the liquid phase volume in the calculation of foam quality as a previous author has implied. Certainly the volume of proppant should be accounted for in the designed rate of the foam treatment.

Stable foam bubbles at reservoir temperature and pressure conditions are stabilized by the following factors:

1. Surfactant effect (surface tension)
2. Gel stabilizer effect (optional) (viscosity)
3. Pressure at temperature (bubble drainage control)

The removal of these factors allows the foam to begin to break in a sequence as follows:

1. As the well is opened to the atmosphere flowback begins as the foam nearest the early pressure drop begins to expand. This expansion weakens the surface energy of the bubbles allowing them to coalesce. As expansion and coalescence continues the foam quality increases to beyond 92.5 percent. At this point with the subsequent pressure drop the foam turns into a mist of liquid droplets in gas. This mist has low viscosity and can no longer provide support for the third or particle phase which is the proppant.

2. The expansion/coalescence trend dominoes from the fracture region through the perforations and into the wellbore.

3. If optimum flowback procedures are followed the maximum expansion/coalescence is timed so that the stable foam is broken in successive pressure drop sequences culminating at the wellbore in a broken mist.

4. As the mist begins to climb the wellbore tubulars it may encounter turbulence and compression due to back pressure from the choke assembly. Foam may be regenerated, but should not be carrying proppant. The regeneration of foam after breaking and leaving proppant behind in the fracture can be an advantage in maintaining stimultaneous recovery of both gas and liquid.

5. This bubble breakback to mist and foam regeneration is simplified in Figure 2 for reference purposes. Sizes are not to scale. Previous work by Holcomb, Callaway and Curry (2) indicates that a pressure drop of 1500 psi allows bubbles 0.3mm in diameter to expand to over 1.25mm in size at ambient temperatures. Micro-video photography has previously shown this expansion/coalescence which is suspected to be responsible for foams breaking.

6. Using too much foaming agent can cause overstability in foams and not allow this expansion/coalescence mechanism to take place, thereby causing foam blockage and/or proppant flowback. Stabilizing agents or gelling materials used in the liquid can cause this same effect if used in too high a concentration.

7. Generally 0.3 percent to no more than 1.5 percent by volume of foaming agent is required in the liquid phase to produce adequately stable foams which will carry proppant for the length of the pump time and yet allow effective foam breakback. Concentrations of foaming surfactant will vary with temperature and pressure conditions as well as with the type of base liquid foamed. See data for aqueous and hydrocarbon foams in references (2) and (3).

8. Not using enough foaming surfactant and/or foam stabilizing polymer can

cause premature foam instability which can lead to job screenout or high foam inefficiency.

ADVANTAGES OF PROPER FLOWBACK

1. The recovery of the majority of treatment fluid allows for minimum damage caused to reservoir permeability adjacent to the created fracture face. Since foam is usually 65-75 percent gas, only 25-35 percent of the treatment must be recovered. Following the prescribed procedures in this paper will allow maximum recovery of any load fluid.

2. Controlled flowback allows simultaneous recovery of both the gas phase (nitrogen) and the liquid phase (water, brine, hydrocarbon or alcohol). Opening up a well too rapidly during flowback causes a too rapid bubble expansion which allows the gas to be released too quickly, leaving the liquid phase essentially unrecovered. Flowing back a foam treatment too quickly can also regenerate the foam via the turbulence generated, and literally "drag" proppant into the wellbore and even to the surface.

   Too long a shut-in after foam fracturing causes the foam to drain and build up a high hydrostatic fluid column which after recovery of a nitrogen gas cap causes the flowback to cease. Nitrogen in the foam located in the fracture will also dissipate into the reservoir as the life of the foam is exhausted. This negates the advantage of gas assist to recover the liquid from the farthest reaches of the created fracture system.

   One additional factor which is possible when wells are opened too much, too quickly after a foam fracture treatment is collapsed casing. If negative pressures caused by the rapid venting of nitrogen from the wellhead override the expansion pressure factor due to friction heating and bottom hole temperature it is possible for the casing to be collapsed. This, of course, would disasterously affect the subsequent productivity of the well. Proper flowback control can lessen the likelihood this will happen.

   The need for well servicing after a foam treatment should be eliminated or reduced if these procedures are followed. Swabbing can be costly as well as time consuming, neither of which adds to the cost-effectiveness of the treatment.

PROPER PROCEDURE FOR FLOWBACK

Remembering the mechanism for foam break back the following step wise flowback regime should be followed after shut-in is established. The shortest time possible is desirable for bringing back foam treatments. Shut-in time should be gauged to allow the following parameters:

1. Gradual expansion of stable foams from between 65 percent and 75 percent gas or quality to in excess of 92.5 percent gas or quality at which point liquid is dispersed in gas as a mist. A stable foam no longer exists.

2. The stimultaneous recovery of the liquid and gas phases throughout the flowback time is desired. Allowing one phase to overcome the other generally leads to poor load recovery. When the liquid phase overrides the gas, hydrostatic head is created which could kill the energized flowback. When the gas phase overrides the liquid, liquid remains in the

fracture causing potential damage to the formation and ultimate poor load recovery as well as poorer than expected well productivity.

3. Allow any foam stabilizing gel used to aid in proppant transport to the point foam is created to break. Usually low gel concentrations (10-30 lbs./1000 gals. of liquid phase) are used for this purpose as well as to stabilize the foam. Returned gel viscosities should be 10 cps. viscosity or less to prevent proppant-in-foam carry back.

4. Allow the half-life of the surfactant foam times approximately five to occur. This discounts most of the surfactant's effectiveness so that bubble collapse occurs allowing broken foam flowback.

5. Allow for fracture closure to withhold proppant.

A procedure which allows the above to occur optimumly is as follows(4):

1. Shut-in the treatment for a time equivalent to that necessary based on the preceding parameters. Shut-in time should be between thirty minutes to no longer than four hours.

2. Have the wellhead rigged with an adjustable choke assembly, preferably remote actuated. A safety control valve should be installed in the flow line in case the choke malfunctions or is cut out.

3. Have a flow line laid, staked and chained to a tank or pit where gas and fluid can be flowed. All personnel should maintain a safe distance from the wellhead and flowback lines.

4. Have a pressure gauge rigged on the wellhead to monitor pressures while the well is flowing in order to establish that fracture closure has probably occurred.

5. Open the adjustable choke to the 12/64 inch setting and begin flowback.

6. Allow the flush volume to be recovered. If nitrogen was used to flush wait until liquid with nitrogen appears. If foam is used to flush, approximate the time to recover the flush volume.

7. After the flush volume is recovered attempt to recover a sample if a significant amount of proppant is suspected in the flow stream. "Significant" proppant is over 50 grains trapped in a steel cup (approx. 1/2 pint) after being held at a slight angle to the flowing nitrogen/liquid stream for 10 seconds.

8. If proppant recovery appears to be significant, shut-in the wellhead for fifteen minutes and resume the 12/64 inch opening procedure again.

9. If no significant proppant is detected open the choke to 24/64 inch for one hour.

10. If there is still an insignificant amount of proppant in the return flow open the choke to 36/64 inch for the next hour, and finally open the choke to 48/64 inch for the remainder of flowback or until significant proppant is detected.

11. Should significant proppant be detected at any point during the flowback the well should be shut-in and the flowback resumed after fifteen minutes at step 5 on the 12/64 inch choke setting.

12. Flowback should be monitored continuously until the maximum load is recovered, and the well is placed on production.

13. Pressure should be monitored continuously during flowback to assure that fracture closure is maintained. It is possible that if gas expansion at reservoir pressure and temperature is significant the fracture could be reopened to allow proppant flowback. Should that occur the well should be shut-in again to allow reclosure of the fracture.

Obviously different wellbore and wellhead assemblies are encountered depending on the well to be foam fractured. Other mechanical possibilities exist for flowback control, but this method has worked best for the author.

PROPPANT FLOWBACK PREVENTION

Since fracturing's primary goal is to place proppant in the created fracture to increase fracture conductivity, and thus well productivity via a greater effective wellbore radius, proppant flowback into the wellbore is undesirable.

Too rapid a flowback could cause regeneration of the foam which in turn would be able to carry proppant into the wellbore, and even to the surface. Proppant flowback is responsible for the following:

1. Reduced fracture conductivity, especially near the wellbore.

2. Wellbore "fill" which must be circulated or bailed out before the well can be produced efficiently.

3. Damage to tubulars, wellhead assemblies, and valves as well as the chokes used for controlled flowback.

Some proppant flowback is associated with almost any type of fracturing treatment, and if kept to a minimum causes little harm. However, the added influence of gas assist from a foam treatment can increase the magnitude of this problem significantly.

Proppant flowback can be minimized by the following steps:

1. Adequately flush the proppant at least to the perforations.

2. Although not desirable with conventional treatment fluids, foam can be overflushed slightly in order to anticipate some regeneration, and subsequent flowback of proppant toward the wellbore before fracture closure is complete. Never overflush in excess of 5 percent of the tubular volume.

3. The choke assembly on the wellhead should be an adjustable type with a high steel alloy or tungsten carbide material in the valve seating. Proppants such as sand will not cut out conventional materials as readily as proppants such as sintered bauxite, intermediate strength bauxite or zirconium based proppants. New alloys or metals are constantly being

researched for such applications. While tungsten carbide is considered the best material, new materials such as silicon carbide are being tried.

4. Positive, non-adjustable chokes are not usually recommended due to the trouble associated with changing out the various size choke beans. This involves periodically shutting in the well in order to accomplish the change out.

5. Following the steps outlined in the section on proper procedure for foam flowback will allow the foam to break back uniformly as it leaves the fracture through the perforations and travels up the wellbore tubulars to the surface, thus leaving the proppant in the fracture.

PRESSURE ANALYSIS DURING FOAM FLOWBACK

The monitoring of pressure during and after shut-in of a foam treatment is important in determining if fracture closure has occurred. Generally a corrected bottom hole treating pressure (BHTP) is determined using the average wellhead treating pressure (P_{WH}), foam hydrostatic head (P_H), and friction pressure (P_F). This number (BHTP) can also be determined from the instantaneous shut-in pressure and a hydrostatic head for a stable column of known quality foam.

In either case the closure stress pressure (P_{CS}) is equal to the bottom hole treating pressure (BHTP) minus the reservoir pressure (P_{RES}) or:

$$P_{CS} = BHTP - P_{RES}$$

It is desirable to maintain the flowback pressure at a level approximately 200 psi below the pressure necessary to maintain fracture closure stress, and thereby keep the proppant within the "healed" fracture system.

While it is generally assumed that once closure is achieved it is irreversible, it could be possible for gas expansion within the fracture to reopen the fracture and allow some proppant flowback. Continuous flowback monitoring will prevent this from occurring.

CONCLUSIONS

1. The mechanism for foams breaking to allow efficient flowback without proppant is controllable.

2. Correct flowback procedures are keys to successful foam stimulation because:

   a. Treatment load recovery is improved.
   b. Proppant flowback is minimized.
   c. Less damage to sensitive reservoirs is caused.
   d. Time to recover or make the well productive is reduced.
   e. Collapsed casing can be avoided.

3. Controlled flowback using an adjustable choke assembly, pressure monitoring gauge and staked flowlines allows for better and safer control of foam flowback. Remote actuated chokes are desirable.

4. Pressure analysis during flowback insures that fracture closure is maintained during flowback; keeping the proppant where it belongs - in the fracture.

REFERENCES

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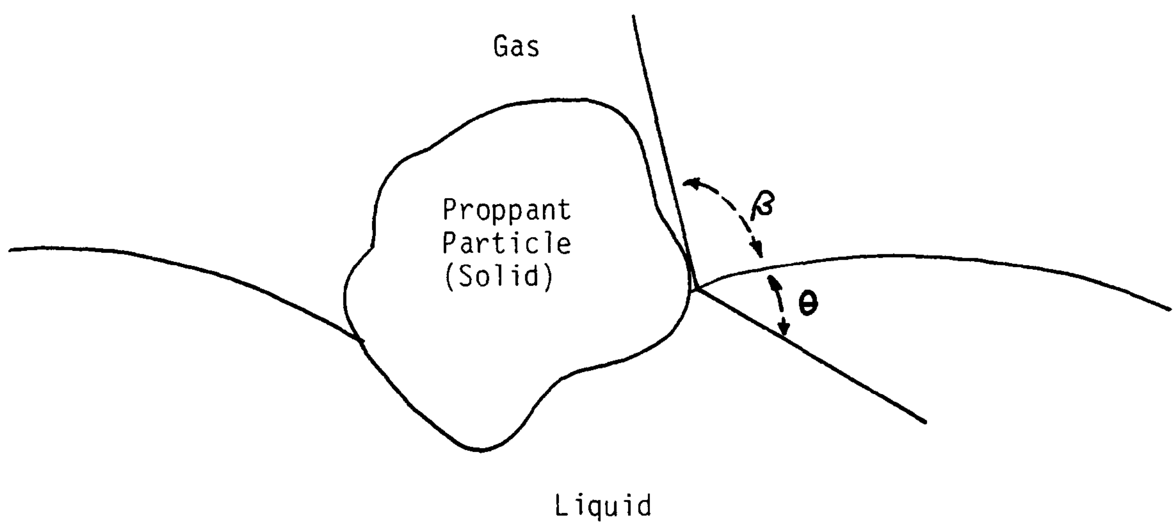

FIGURE 1 — SOLID PARTICLES SUSPENDED IN GAS-LIQUID BOUNDARY BY SURFACE TENSION. B IS THE ANGLE FORMED BY THE VERTICAL WITH LIQUID SURFACE AT A POINT OF THE THREE PHASE LINE, AND Θ IS THE CONTACT ANGLE AT THIS POINT. (1)

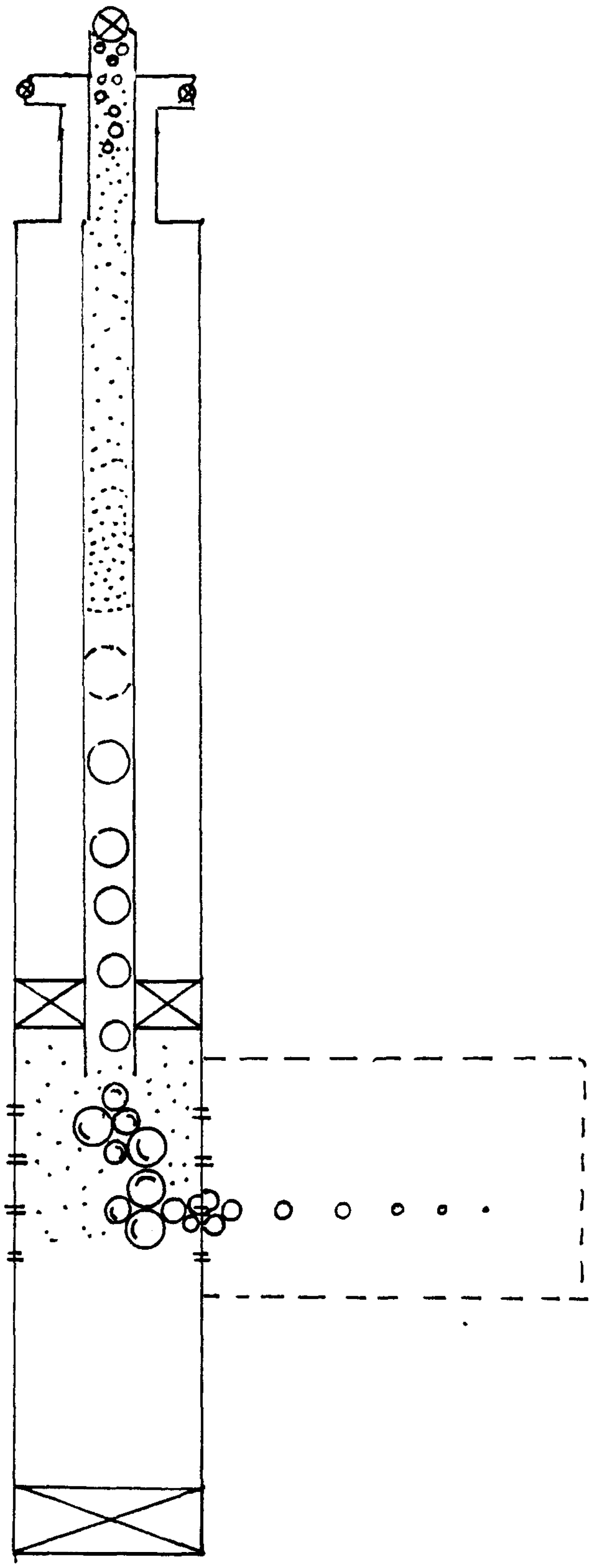

FIGURE 2 — WELLBORE SCHEMATIC ILLUSTRATING HOW STABLE BUBBLES 0.3mm IN SIZE ENLARGE AND EVENTUALLY COALESCE IN THE TUBING UPON FLOWBACK. NOTE STABLE BUBBLES ARE BEGINNING TO REGENERATE NEAR THE SURFACE AS BACK PRESSURE ENCOUNTERED.