EQUIPMENT CONSIDERATIONS IN CARBON DIOXIDE FLOODING

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ABSTRACT

The intended functions of wellbore equipment in injection or producing wells are to provide well control and safety. It is only in a situation where both of these are provided that efficient, trouble free operations can be depended on. Enhanced oil recovery places unique demands on wellbore equipment which must be planned for during completion design. This paper discusses techniques and equipment which can be utilized to provide the necessary well control and safety in carbon dioxide flooding operations.

A complete treating of the subject discussing exhaustively the aspects of possible design combinations would require voluminous material not possible in a paper such as this. Therefore it is the authors' intent to discuss what we believe to be very important considerations within the subject and give enough case history information to help the reader set the tone for a comprehensive study of his individual situation.

PROBLEMS ENCOUNTERED IN CARBON DIOXIDE FLOODING

Corrosive Effects on Metals

Carbon dioxide in the presence of water will chemically attack metallic surfaces to corrode them. With the corrosion tendencies of the carbon dioxide added to possible existing corrosion problems due to hydrogen sulfide and a high concentration of chlorides in the injection water as well as in the produced fluids, corrosion becomes an especially troublesome problem in carbon dioxide flooding projects. A carbon dioxide flood will tend to accelerate the corrosion problems that were experienced during a previous waterflood because the carbon dioxide brings the pH balance down enhancing the already corrosive nature of the environment. It must be kept in mind that no single approach solves all problems related to carbon dioxide corrosion. While one system might work extremely well in one wellbore environment, it may fail in another. For this reason, as much test data and as many case histories as possible must be considered in each equipment recommendation for a carbon dioxide flooding application. In general, corrosion problems are not as severe in the injection wells as they are in the producing wells.

Physical Effects on Elastomers

The two troublesome effects commonly noted after exposure of a rubber part to carbon dioxide rich fluids are swelling and blistering. Swelling enlarges the entire part whereas blistering is more localized. The swelling is a result of chemical compatibility of the elastomer with the carbon dioxide. Blistering has its origin in the vacuoles and non-knit areas of the rubber compound. Both effects are undesirable, but swelling is the principal cause of most of the problems associated with the use of elastomers in carbon dioxide environments.

Physical growth of elastomer tool parts downhole can cause removal problems. The tool may stick and wedge in the wellbore, causing considerable problems for the operator. Also the swabbing of fluid by a swelled packer rubber during retrieval can be troublesome and add to well control problems since it actually contributes toward bringing the well in.

Wellbore Control Problems

In many areas where injection wells historically have been killed by backflowing prior to workovers in waterfloods, this is no longer possible after converting to carbon dioxide injection. After only a few weeks of carbon dioxide injection many wells will instead require kill fluids to control during workover cycle. The carbon dioxide will feed into the wellbore and cut the kill fluids as they are being circulated sometimes making the procedure dangerous.

Effects on Packoff Reliability

The wellbore temperatures encountered in carbon dioxide flooding especially in the Permian Basin are not typically high compared with wellbore temperatures encountered in other aspects of oil production. At these temperatures the swell resulting from exposure to carbon dioxide is inversely proprotional to the hardness of a rubber part used at these temperatures. Because of this a tendency exist toward using hard packing elements. This coupled with the fact that carbon dioxide is a difficult fluid to contain results in difficulty in getting a packoff which is effective in sealing against the carbon dioxide.

Effects on Tubing Joint Sealing Reliability

One of the most troublesome problems in carbon dioxide injection wells is leakage at the tubing couplings. Experience has shown that the carbon dioxide is much more difficult to contain than the injection water used in waterflooding and that the API type tubing threads traditionally used are not reliable without special modifications for the carbon dioxide service. Premium tubing joints offer a potential solution to this problem.

TOOLS TO USE FOR SOLUTIONS

A lot of tools are available to the operator for trying to combat the problems discussed above. Some of these are stainless steels, non-ferrous alloys, coatings, corrosion inhibitors, non-metallic tubulars and rubber compounding. Each of these are important tools and the proper applications of these can solve many of the problems which would otherwise be severe. These have all received much attention by operators. There are two other tools which the authors believe are equally important however which have received less overall attention. These are the "back to the basics" tools of completion design and wellsite procedures. Without the proper application of these tools the use of the other tools will be greatly impaired.

A good example of this is the fact that careless wellsite handling of coated parts can render a coating completely ineffective. Another example is that a poor completion design which does not allow for proper inhibitor application can keep the best inhibitor from preventing corrosion.

Five case histories are given in the remainder of this paper which illustrate the need for proper design and wellsite procedures. We do not attempt to cover the entire field with these five examples, but we believe they will illustrate how attention to detail is important. Three of the case histories involve non-metallic tubulars. Perhaps none of the tools available to the carbon dioxide flood operator requires more attention to design and procedures than does this one. The other two case histories illustrate heavily how the selection of packer equipment and wellsite procedures can contribute to wellbore control.

CASE HISTORIES--NON-METALLIC TUBULARS

Non-metallic tubulars are known in the industry as fiber glass tubing and casing. Where depth or pressure limitations do not preclude their use they offer a material which is not affected by the corrosive environment present downhole in most carbon dioxide floods. One of the major obstacles with the use of these materials in the past was a perceived incompatibility with packer equipment. Case histories are given concerning both setting packers with fiber glass tubing and setting packers in fiber glass casing. The primary concerns which must be considered in setting a packer on fiber glass tubing are: 1) The intergal joint strength of the tubing; 2) The weight of the tubing string in the wellbore fluid; 3)The tension forces required to set and release the packer; and 4) The amount of torque required to set and release the packer.
The primary concern of setting a packer in fiber glass casing is potential casing damage. Because no two brands of fiber glass materials have the same physical properties care must be taken to use the data supplied by the specific manufacturer of concern.

Setting on Fiber Glass Tubing

In a recent Kansas completion using a Guiberson Uni-Packer VI packer the operator used the following procedure:

Run in wellbore with the packer, on-off tool and six joints of steel tubing to start the packer;
Set the packer six joints in the wellbore
Release the on-off tool and pull six joints of steel tubing out of the hole;
Go back in the hole with six joints of fiber glass tubing and recouple the on-off tool;
Run the packer to 3892' on the fiber glass tubing and set the packer with 8000 lbs. tension;
Flange up the wellhead with 7000 lbs tension left in packer;
Load the hole and test.

The steel tubing was used in this case to supply enough weight to start in the wellbore.

In another recent completion, this one in west Texas, using a 5 1/2" Guiberson ER-VI packer and 2 3/8" fiber glass tubing with a rated axial load capacity of 14000 lbs the operator installed the packer at 4800'.

The most important factor to consider in an installation of this type is whether or not enought axial load carrying capability is available to allow enough tension to be pulled into the packer to insure competent packoff. With the packer which was used 7500 lbs. is required to insure packoff. The following calculations were performed to plan for this particular situation:

Weight of tubing in air:	4,800 ft X 1.72 lbs/ft + 8256 lbs
Buoyance force in 9.0 ppg fluid:	4800' X .0519 X 9.0 ppg X 144 sq in = 3228 lbs
Tubing weight in fluid:	8256 - 3228 = 5028 lbs
Available tension:	14000 - 5028 = 8972 lbs

The calculations show that this installation is possible. It was in fact installed with no problems. In the case of this installation, the packer was not started in the wellbore with the help of steel tubing; but was run from the surface on fiber glass tubing. An on-off tool was not utilized, but a stainless steel pup joint was run just above the packer to be used as an emergency fishing neck if necessary.

Setting Packers in Fiber Glass Casing

A laboratory test was recently run demonstrating the effects of setting a packer inside fiber glass casing. This test was performed in Dallas, Texas by representatives of Guiberson, a manufacturer of fiber glass casing and a major oil company. The test demonstrated that successful installation of a packer can be done within fiber glass casing if the casing is supported by a competent cement sheath.

A 15 ft. joint of 5 1/2" O.D. x 4 3/4" I.D. fiber glass casing was cemented inside a joint of 9 5/8" steel casing to simulate the situation of being cemented inside a wellbore. The bottom of the fiber glass casing was bull-plugged. This test pot was then pressure tested to 2000 psi to insure that there were no leaks before the test was begun.

The test pot was then lowered into a special environmental test pot recepticle and flanged up to a head at the surface. Hot oil was circulated around the outside of the 9 5/8" casing until the entire assembly was stabilized at 110 degrees F.

At this point a Guiberson Uni-Packer VI packer with three 75 durometer packing elements was set inside the fiber glass reinforced casing. The packer was connected to a polished rod which passed through a pressure containing gland on the surface head with a 2 3/8" fiber glass reinforced pup joint. All setting and releasing actions were acheived by manulations through this pup joint.

The packer was set using 8000 pounds of tension to acheive rubber system packoff. Three pressure cycles of 2000 psi were then applied to the packer. A pressure cycle consisted of pressuring first below the packer for 30 minutes and then releasing that pressure and pressuring above the packer for 30 minutes.

No leaks were observed during any of the pressure cycles. After completion of the three cycles the packer was released and pulled from the casing.

The casing was then cut into two halves so that damage to the inside of the fiber glass reinforced casing could be assessed. It was found that damage was limiteds to the area of tooth contact of the packer slips and was also limited to the depth of tooth penetration.

The consensus of those running the test was that suitable performance was demonstrated by the fiber glass reinforced casing and packer combination. It should be noted again however that this simulated a condition with supported pipe. Similar test with fiber glass reinforced casing in an unsupported situation have resulted in extensive damage to the casing.

CASE HISTORY--INJECTION WELL CONTROL

In a recent West Texas example where the average injection well depth was 2900' problems were encountered during workover operations with wellbore control. After a few weeks of carbon dioxide injection at 1400 psig it became impractical to kill the injection wells by backflowing. Most of the wells were pressured to a point such that there was 800 to 1100 psi shut-in tubing pressure, and the wells would not die after a reasonable period of backflowing. These wells required a kill fluid to enable the required work to be done.

When kill fluids were first used a problem occurred because of small mixing tanks available on location. A slug of kill fluid would be pumped and then while the next slug was being mixed the fluid in the wellbore was being cut by the carbon dioxide flowing back into the wellbore from the formation. Fluids pumped into the wellbore at 16 lb/gal would return at 13 lb/gal. The returning fluid would have to be reconditioned to 16 lb/gal before being pumped again and long delays would occur in the killing operations.

One obvious solution to the problem was to utilize a mixing tank large enough to allow the entire wellbore to be loaded with one batch. Better results were obtained by running a plug in the gudgeon section of the on-off connector, uncoupling the overshot and circulating the kill fluid above the packer. With the wellbore full of mud at the required weight the tubing could be recoupled and the packer released.

CASE HISTORY--PACKER APPLICATION

Chosing the proper packer for the application is very important as is illustrated by a case history involving a 4800' deep west Texas well which was being converted from water injection to a WAG injector in a carbon dioxide flooding project. The initial packer of choice for this installation was a simple tension packer as had been used during the waterflooding operations.

Force analyses were performed to cover the cases of water injection, carbon dioxide injection and well killing. The computer printouts obtained during the force analyses follow this discussion.

Looking at the analysis for the water injection case it can be seen that a force of nearly 29000 lbs is being transmitted through the shear pins of the packer. Since the shear pins in this type of packer are brass they are subject to being sheared by long term loads which are greater than half their rated load. The force analysis was prepared assuming worst case conditions, however. Knowing this the decision was made to go ahead with installation of this type of packer in the original water flood. This decision was made with the knowlege that if the packer did shear and release the operator could bleed the pressure off by backflowing, pull the well, re-dress the packer and run back into the wellbore to restart injection. The cost of this would be low in both time and money compared to the cost of running a more sophisticated packer design thoughout the entire project. This proved over the years to be a sound decision on the part of the operator for very few of the packers did shear out and had to be pulled.

When the field was converted to carbon dioxide injection the concern of packers prematurely shearing became extremely important. Again looking at the force analysis for the carbon dioxide injection stage we find again that there is a danger of shearing out over a long time. The analysis shows over 25000 lbs being carried through the shear pins. If the packer did prematurely shear the loss of expensive carbon dioxide would be a major concern. More important than that the problem of trying to regain control of the well with carbon dioxide being fed into the well from the formation is severe. Experience has shown that mud in excess of 13.5 ppg would be required to kill the well. A force analysis was run assuming injection of mud into the well with a packer which had not sheared. The forces are unacceptable even in this case where the control offered by the packer is of utmost importance. In an actual case in this field 14.0 ppg mud was required to achieve control and it was necessary to begin the process with 16.0 ppg fluid because of the rapid cutting of the mud by the carbon dioxide. One of the most critical problems encountered during this operation was the pressure which was on the casing from the time the packer sheared until the well was killed.

The recommended completion equipment for the wells in the last two case histories would include a double grip type packer which would allow the packer to be set in tension or compression, an on-off tool with a profile nipple in the gudgeon section, and a downhole shut off valve run between the packer and the on-off tool. The packer will elimate the possibility of premature shear with these conditions. The shut off valve will allow the well to be shut in at the packer while the tubing is disconnected at the on-off tool to facilitate circulation of kill fluid without the action of carbon dioxide cutting the fluid. The profile in the on-off tool offers a redundant option for shutting in the well at the packer while kill fluids are being circulated. The use of this equipment will prevent premature failure of the wellbore equipment and will allow control of the wellbore when work does become necessary.

A COMPUTER CALCULATED
SINGLE STRING ANALYSIS
COMPLIMENTS OF
G U I B E R S O N

ANALYSIS FOR:
SHORT COURSE
LUBBOCK TEXAS

01/30/85

WELL NAME AND NUMBER:
CO2 INJECTION WELLS
WEST TEXAS

TYPE OF INSTALLATION:
CO2 INJECTION STAGE ASSUME 6.5 PPG CO2

WELL DATA:	
LENGTH OF TUBING	4800. FT.
CASING I.D.	4.950 IN.
TUBING I.D.	1.995 IN.
TUBING O.D.	2.375 IN.
TUBING WEIGHT	4.700 LB./FT.
TUBING YIELD STRENGTH	55000. PSI
INT. FLUID WEIGHT IN TUB.	8.33 LB./GAL.
INT. FLUID WEIGHT IN ANN.	8.33 LB./GAL.
FIN. FLUID WEIGHT IN TUB.	6.50 LB./GAL.
FIN. FLUID WEIGHT IN ANN.	8.33 LB./GAL.
INT. APPLIED SURF. TUB. PRESS.	0. PSI
INT. APPLIED SURF. CSG. PRESS.	0. PSI
FIN. APPLIED SURF. TUB. PRESS.	1400. PSI
FIN. APPLIED SURF. CSG. PRESS.	0. PSI
INITIAL TEMPERATURE AT TOP	65. DEG.(F)
INITIAL BOTTOM HOLE TEMPERATURE	100. DEG.(F)
FINAL TEMPERATURE AT TOP	65. DEG.(F)
FINAL BOTTOM HOLE TEMPERATURE	65. DEG.(F)
INITIAL TENSION PULLED	-15000. LBS.
TYPE OF PACKER	5 1/2 UNI-PACKER I
PACKER CODE	2
PACKER TO TUBING RELATIONSHIP	LATCHED
PACKER VALVE OR SEAL DIAMETER	3.000 IN.
SHEAR VALUE OF PACKER	40000. LBS.
TOTAL FRICTION LOSS IN TUBING	0 PSI

CALCULATED VALUES:

TUBING OUTER FIBER STRESS	15065. PSI
TUBING INNER FIBER STRESS	15570. PSI

PRESSURE CHANGES (-) MEANS DIFFERENTIAL UP (+) MEANS DIFFERENTIAL DOWN

FINAL DIFFERENTIAL AT SURFACE	-1400. PSI
FINAL DIFFERENTIAL AT PACKER	-943. PSI

LENGTH CHANGES AND/OR FORCE CHANGES
(-) MEANS AN UPWARD MOVEMENT OR A TENSION FORCE
(+) MEANS A DOWNWARD MOVEMENT OR A COMPRESSIVE FORCE

EQUIVALENT LENGTH CHANGES AT THE PACKER			
INITIAL TENSION PULLED	-22. IN.		-1.8 FT.
PISTON EFFECT	-5. IN.		-.5 FT.
BUCKLING EFFECT	-1. IN.	OR	-.1 FT.
BALLOONING EFFECT	-3. IN.		-.3 FT.
TEMPERATURE EFFECT	-7. IN.		-.6 FT.
TOTAL EFFECT	-39. IN.		-3.2 FT.

TEMPERATURE EFFECT	-4725. LBS.
TOTAL FORCE OF TUBING ON PACKER	-25641. LBS.
PRESSURE FORCE ACROSS PACKER	-11484. LBS.
TOTAL NET FORCE ACROSS PACKER	-37125. LBS.

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CAUTION - CALCULATIONS INDICATE THAT THE TOTAL FORCE CARRIED THROUGH THE SHEAR PINS IS -25641. LBS. UP. THIS FORCE COULD CAUSE THE SHEAR PINS TO PREMAURELY SHEAR OUT SINCE IT IS GREATER THAN 50% OF THE TOTAL SHEAR PIN VALUE OF 20000. LBS.
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TENSION IN TUBING AT TOP JOINT +41770. LBS.

A COMPUTER CALCULATED
SINGLE STRING ANALYSIS
COMPLIMENTS OF
G U I B E R S O N

ANALYSIS FOR:
SHORT COURSE
LUBBOCK TEXAS

01/30/85

WELL NAME AND NUMBER:
CO2 INJECTION WELLS
WEST TEXAS

TYPE OF INSTALLATION:
WATER INJECTION STAGE ASSUME 8.7 PPG WATER

WELL DATA:

LENGTH OF TUBING	4800. FT.
CASING I.D.	4.950 IN.
TUBING I.D.	1.995 IN.
TUBING O.D.	2.375 IN.
TUBING WEIGHT	4.700 LB./FT.
TUBING YIELD STRENGTH	55000. PSI
INT. FLUID WEIGHT IN TUB.	8.33 LB./GAL.
INT. FLUID WEIGHT IN ANN.	8.33 LB./GAL.
FIN. FLUID WEIGHT IN TUB.	8.70 LB./GAL.
FIN. FLUID WEIGHT IN ANN.	8.33 LB./GAL.
INT. APPLIED SURF. TUB. PRESS.	0. PSI
INT. APPLIED SURF. CSG. PRESS.	0. PSI
FIN. APPLIED SURF. TUB. PRESS.	1500. PSI
FIN. APPLIED SURF. CSG. PRESS.	0. PSI
INITIAL TEMPERATURE AT TOP	65. DEG.(F)
INITIAL BOTTOM HOLE TEMPERATURE	100. DEG.(F)
FINAL TEMPERATURE AT TOP	65. DEG.(F)
FINAL BOTTOM HOLE TEMPERATURE	65. DEG.(F)
INITIAL TENSION PULLED	-15000. LBS.
TYPE OF PACKER	5 1/2 UNI-PACKER I
PACKER CODE	2
PACKER TO TUBING RELATIONSHIP	LATCHED
PACKER VALVE OR SEAL DIAMETER	3.000 IN.
SHEAR VALUE OF PACKER	40000. LBS.
TOTAL FRICTION LOSS IN TUBING	0 PSI

CALCULATED VALUES:

TUBING OUTER FIBER STRESS	15059. PSI
TUBING INNER FIBER STRESS	16457. PSI

PRESSURE CHANGES (-) MEANS DIFFERENTIAL UP (+) MEANS DIFFERENTIAL DOWN

FINAL DIFFERENTIAL AT SURFACE	-1500. PSI
FINAL DIFFERENTIAL AT PACKER	-1592. PSI

LENGTH CHANGES AND/OR FORCE CHANGES
(-) MEANS AN UPWARD MOVEMENT OR A TENSION FORCE
(+) MEANS A DOWNWARD MOVEMENT OR A COMPRESSIVE FORCE

EQUIVALENT LENGTH CHANGES AT THE PACKER

INITIAL TENSION PULLED	-22. IN.		-1.8 FT.
PISTON EFFECT	-9. IN.		-.8 FT.
BUCKLING EFFECT	-3. IN.	OR	-.3 FT.
BALLOONING EFFECT	-4. IN.		-.4 FT.
TEMPERATURE EFFECT	-7. IN.		-.6 FT.
TOTAL EFFECT	-46. IN.		-3.8 FT.

TEMPERATURE EFFECT	-4725. LBS.
TOTAL FORCE OF TUBING ON PACKER	-28903. LBS.
PRESSURE FORCE ACROSS PACKER	-19388. LBS.
TOTAL NET FORCE ACROSS PACKER	-48291. LBS.

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CAUTION - CALCULATIONS INDICATE THAT THE TOTAL FORCE CARRIED THROUGH THE SHEAR PINS IS -28903. LBS. UP. THIS FORCE COULD CAUSE THE SHEAR PINS TO PREMAURELY SHEAR OUT SINCE IT IS GREATER THAN 50% OF THE TOTAL SHEAR PIN VALUE OF 20000. LBS.
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TENSION IN TUBING AT TOP JOINT +42473. LBS.

A COMPUTER CALCULATED
SINGLE STRING ANALYSIS
COMPLIMENTS OF
G U I B E R S O N

ANALYSIS FOR:
SHORT COURSE
LUBBOCK TEXAS

01/30/85

WELL NAME AND NUMBER:
CO2 INJECTION WELLS
WEST TEXAS

TYPE OF INSTALLATION:
KILL WELL ASSUME 13.5 PPG MUD DOWN TUBING

WELL DATA:

LENGTH OF TUBING	4800. FT.
CASING I.D.	4.950 IN.
TUBING I.D.	1.995 IN.
TUBING O.D.	2.375 IN.
TUBING WEIGHT	4.700 LB./FT.
TUBING YIELD STRENGTH	55000. PSI
INT. FLUID WEIGHT IN TUB.	8.33 LB./GAL.
INT. FLUID WEIGHT IN ANN.	8.33 LB./GAL.
FIN. FLUID WEIGHT IN TUB.	13.50 LB./GAL.
FIN. FLUID WEIGHT IN ANN.	8.33 LB./GAL.
INT. APPLIED SURF. TUB. PRESS.	0. PSI
INT. APPLIED SURF. CSG. PRESS.	0. PSI
FIN. APPLIED SURF. TUB. PRESS.	0. PSI
FIN. APPLIED SURF. CSG. PRESS.	0. PSI
INITIAL TEMPERATURE AT TOP	65. DEG.(F)
INITIAL BOTTOM HOLE TEMPERATURE	100. DEG.(F)
FINAL TEMPERATURE AT TOP	65. DEG.(F)
FINAL BOTTOM HOLE TEMPERATURE	65. DEG.(F)
INITIAL TENSION PULLED	-15000. LBS.
TYPE OF PACKER	5 1/2 UNI-PACKER I
PACKER CODE	2
PACKER TO TUBING RELATIONSHIP	LATCHED
PACKER VALVE OR SEAL DIAMETER	3.000 IN.
SHEAR VALUE OF PACKER	40000. LBS.
TOTAL FRICTION LOSS IN TUBING	0 PSI

CALCULATED VALUES:

TUBING OUTER FIBER STRESS	14022. PSI
TUBING INNER FIBER STRESS	15019. PSI

PRESSURE CHANGES (-) MEANS DIFFERENTIAL UP (+) MEANS DIFFERENTIAL DOWN

FINAL DIFFERENTIAL AT SURFACE	+0. PSI
FINAL DIFFERENTIAL AT PACKER	-1290. PSI

LENGTH CHANGES AND/OR FORCE CHANGES
(-) MEANS AN UPWARD MOVEMENT OR A TENSION FORCE
(+) MEANS A DOWNWARD MOVEMENT OR A COMPRESSIVE FORCE

EQUIVALENT LENGTH CHANGES AT THE PACKER

INITIAL TENSION PULLED	-22. IN.		-1.8 FT.
PISTON EFFECT	-7. IN.		-.6 FT.
BUCKLING EFFECT	-2. IN.	OR	-.1 FT.
BALLOONING EFFECT	-2. IN.		-.1 FT.
TEMPERATURE EFFECT	-7. IN.		-.6 FT.
TOTAL EFFECT	-40. IN.		-3.3 FT.

TEMPERATURE EFFECT	-4725. LBS.
TOTAL FORCE OF TUBING ON PACKER	-26022. LBS.
PRESSURE FORCE ACROSS PACKER	-15712. LBS.
TOTAL NET FORCE ACROSS PACKER	-41734. LBS.

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CAUTION - CALCULATIONS INDICATE THAT THE TOTAL FORCE CARRIED THROUGH THE SHEAR PINS IS -26022. LBS. UP. THIS FORCE COULD CAUSE THE SHEAR PINS TO PREMAURELY SHEAR OUT SINCE IT IS GREATER THAN 50% OF THE TOTAL SHEAR PIN VALUE OF 20000. LBS.

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TENSION IN TUBING AT TOP JOINT +40783. LBS.

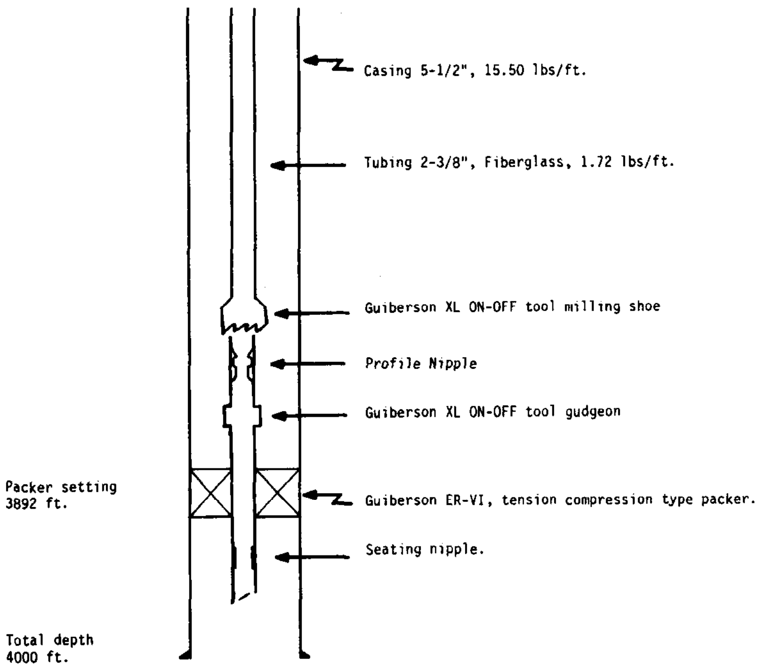

Figure 1 - Recent Kansas completion - fiberglass tubing

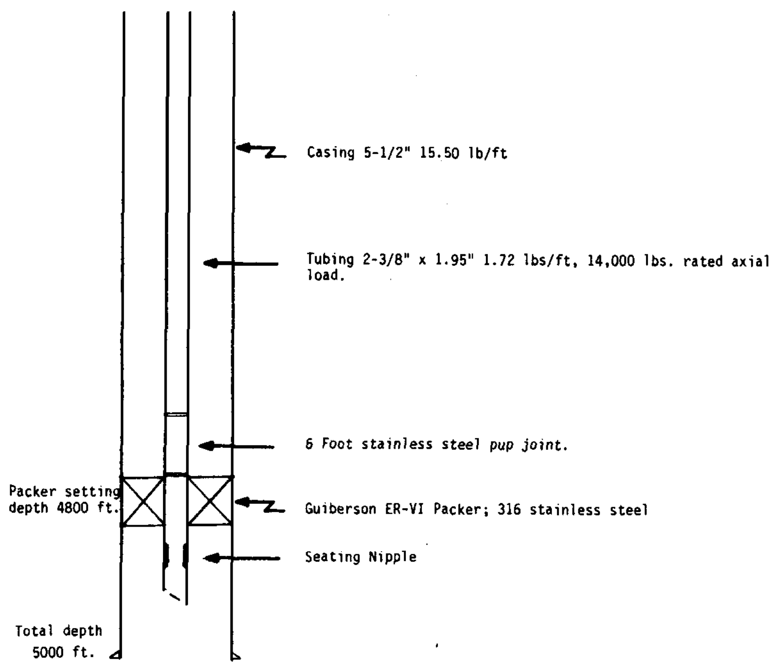

Figure 2 - Recent West Texas completion - fiberglass tubing

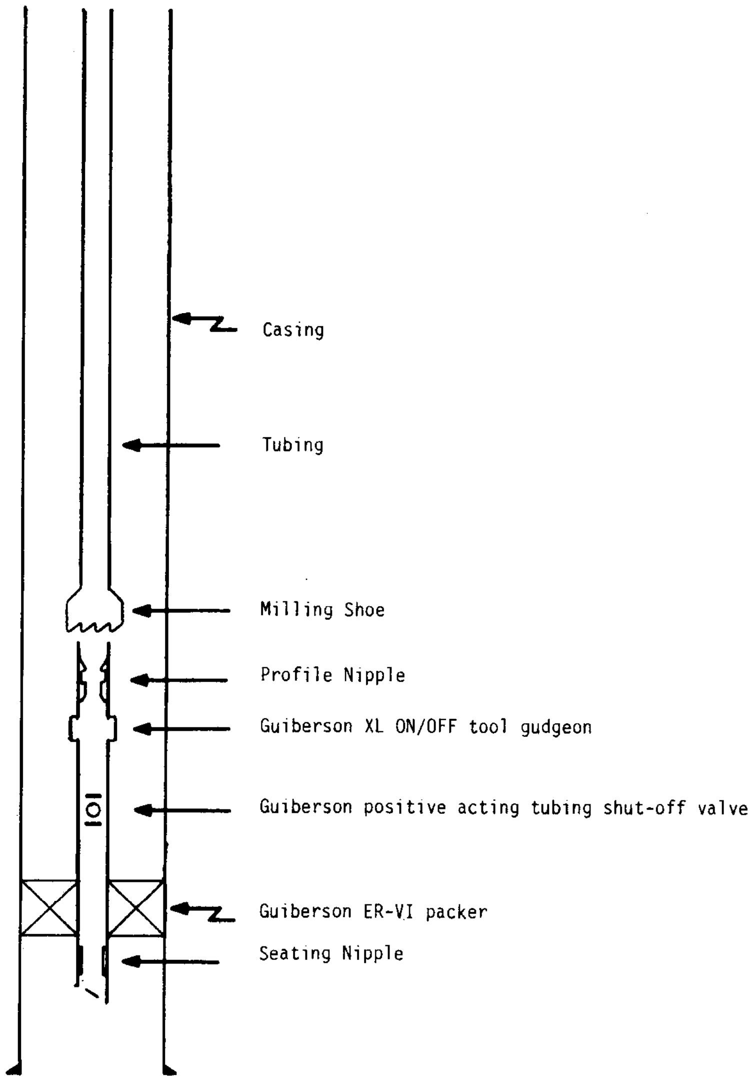

Figure 3 - Recommended completion equipment