WORKING PRESSURE UPGRADING OF WELLHEAD EQUIPMENT FOR STIMULATION WORK

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INTRODUCTION

One of the most common problems encountered in designing a stimulation treatment is a low working pressure rating of surface equipment. Quite often, tubular goods are capable of much higher working pressures than the wellhead equipment, and the primary limit of pressure and injection rate is above ground.

Breakdown and "Ball Out" treatments are often restricted by low working pressure ratings when the maximum allowable pressure at the pump is less than the pressure required to inject fluid into new or fluid-damaged perforations. Even though high pressures may be required for only a few minutes, it is vital to successful completion of a well that each perforation or zone be opened.

Pressure limitations can be especially critical since the fracture area developed and proppant transport are direct functions of injection rate.

When the pressure limiting component of a well system is above ground it can usually be "upgraded" safely and reliably by one of these methods:

1. Isolating the wellhead from treating pressure
2. Substitution of a "Treating Tree" for the production Christmas tree
3. Special landing joints or "Top Out Joints" for working through blow out preventers or wellhead assemblies where conventional trees have not been installed.

Each of these methods has its strong and weak points and warrants detailed examination.

WELLHEAD ISOLATION EQUIPMENT

This is the most convenient and commonly used method of temporarily upgrading the working pressure capability of production equipment. A sealing element and mandrel are inserted through the existing tree bore and tubing hanger into the production tubing. Treating fluids are pumped through the tool mandrel directly into the production tubing. The Christmas tree is completely isolated from treating fluid contact.

There are several isolation tool systems in general use. They vary somewhat in mechanical detail, but have these features in common:

1. Differential pressure initiation of seal elements. No mechanical manipulation of the mandrel is necessary; tubing pressure energizes the seals.
2. They can be installed on a live well. A hydraulic piston system is most commonly used to insert the mandrel/seal assembly. Withdrawal is the reverse of the insertion procedure and can be done under pressure.
3. After hydraulically inserting the seal elements into the tubing, the mandrel assembly is mechanically locked.

The tool assembly shown in Fig. 2 illustrates the basic features of wellhead isolation tools.

The sealing element shown in Fig. 1 consists of a rubber cup which initiates a pressure seal and energizes the packer to effect a high pressure seal. The packer ring is backed by a support shoe to control creep. This element is very similar to some downhole packers in function with the main difference being in dimensional clearances which must be smaller to withstand 15,000 psi working pressure differentials. The isolation tool element is sized much closer to tubing ID than would be practical with packers running through long lengths of pipe.

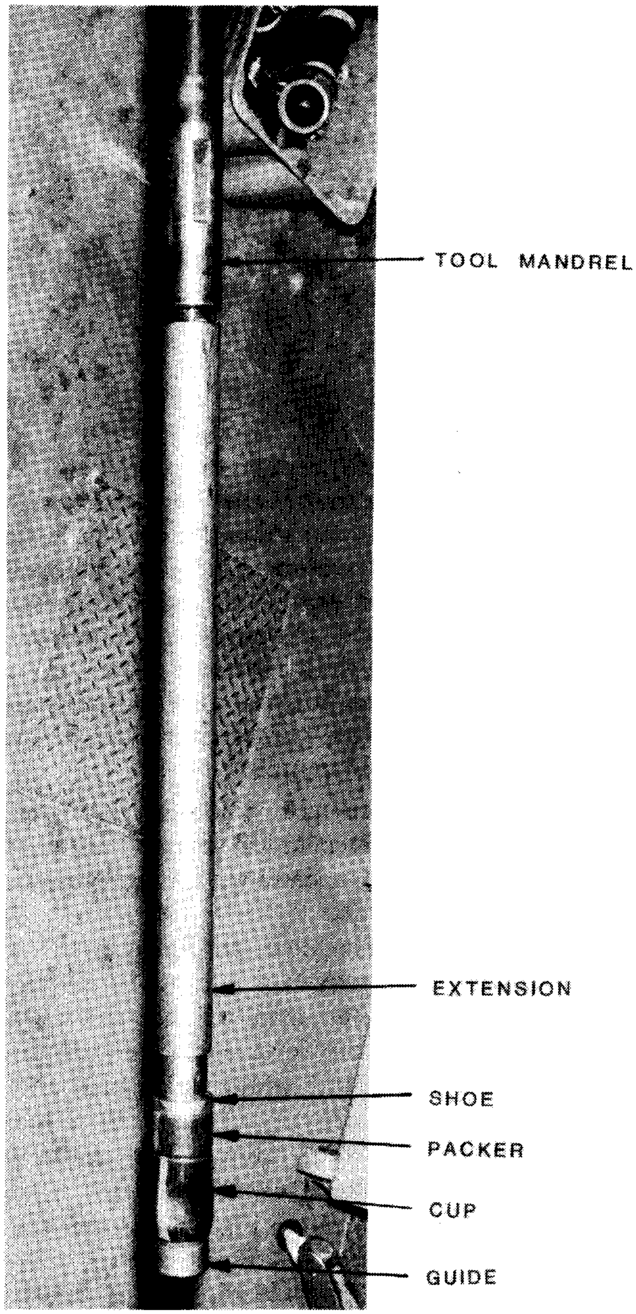

FIGURE I

Because the isolation tool seals are closely sized to the tubing, it is quite important that tubing ID and hanger ID be accurately known when selecting a seal element. Too small a seal element risks a pressure failure, and too large an element invites sticking a mandrel in the tubing.

Mandrel length is adjusted for different tree configurations with extensions, i.e., short subs of various lengths, or by substituting mandrels of assorted lengths. This length must be short enough to clear the master valve gate when the tool is set on the tree, and long enough to reach into the tubing when the mandrel is inserted. This minimum-maximum range may only be one or two inches on some trees and a foot or more on others, depending on the particular tool, tree configuration, and type of tubing hanger. The distinction between mandrels and extensions made here is that the mandrel includes the piston which works inside the hydraulic cylinder.

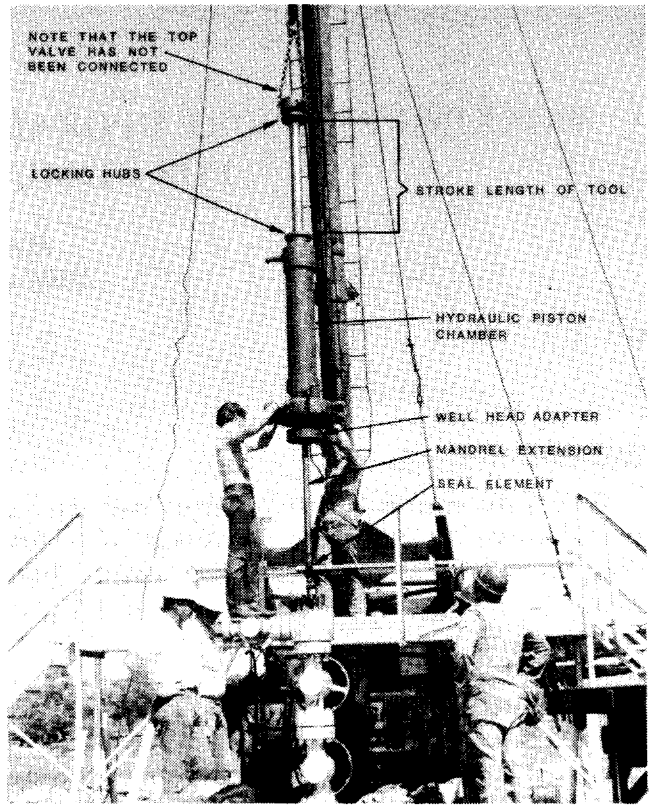

FIG. 2—THE SWAB VALVE HAS BEEN REMOVED FROM THIS TREE, AND THE FLOW LINE DISCONNECTED FROM THE WING VALVE. THE ISOLATION TOOL ASSEMBLY IS BEING SET ON.

Attachment of the tool assembly to the tree is best made by flanges, rather than threaded adapters made up into three caps or companion flanges, because the tools add substantial height to the tree; and when discharge lines are attached, sizable bending loads can be imposed. Flange connections will carry these bending loads much more competently, and they are not subject to wear from repeated makeup that results in leaks under pressure.

Effort should be made to insure that good quality,

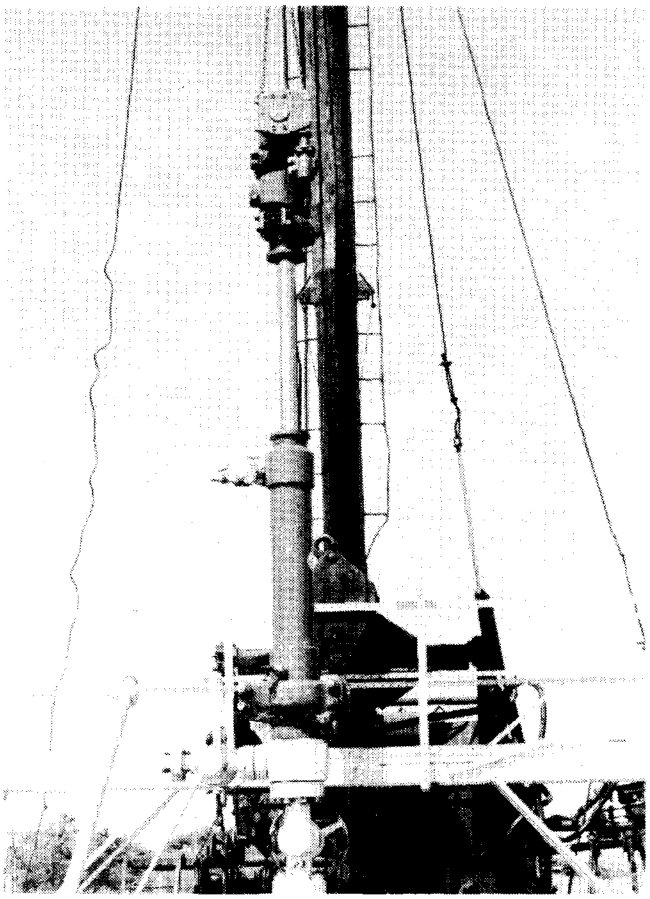

FIG. 3—THE ISOLATION TOOL ASSEMBLY HAS BEEN CONNECTED TO THE FLOW TEE AND IS BEING PRESSURE TESTED. NOTE THE DOUBLE VALVES ON TOP OF THE TOOL. THE TOP VALVE IS REMOTELY OPERATED, THE BOTTOM ONE MANUALLY OPERATED. THE LOWER MASTER VALVE IS CLOSED. TUBING PRESSURE IS 9,400 PSI.

mechanically competent adapters are used every time the isolation tool is installed, because once the wellhead master valve is opened and mandrel insertion started, the master valve is blocked open. Control of the well is absolutely dependent on the tool-tree connection, and the valve on top of the tool mandrel. Expediencies such as threaded connections and double changeovers can seriously reduce pressure and mechanical integrity.

Piston stroke length is an important feature of isolation tools. This length will vary from 36 inches to about 48 inches depending on the size, type and make of the tool.

Installation of the isolation tool is a simple, quick and completely safe procedure if accurate tree dimensions are provided, and reasonable attention given to the nature and limitations of the tools.

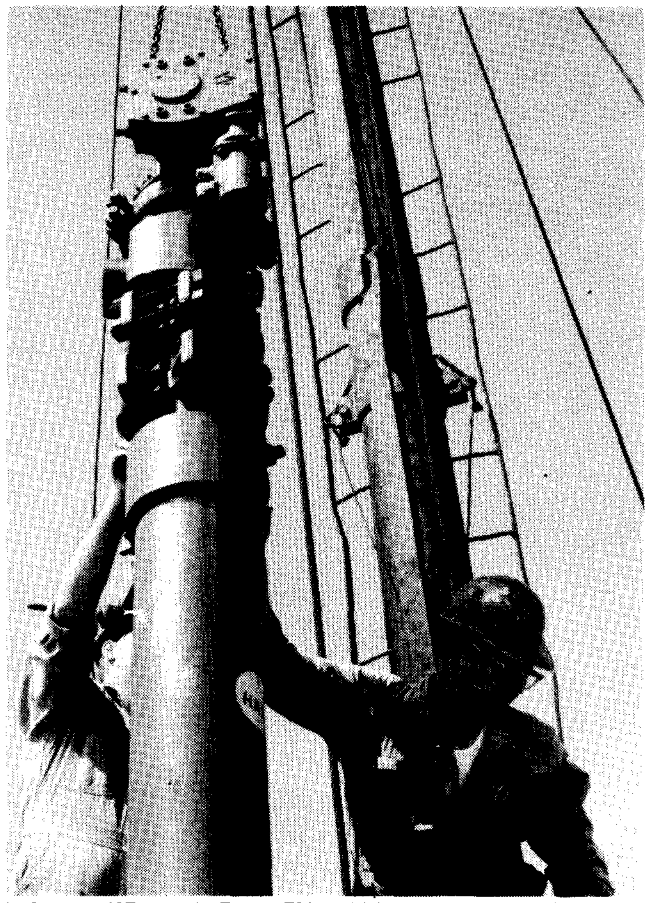

FIG. 4—THE SEAL ELEMENT HAS BEEN INSERTED, THE MANDREL IS FULLY DOWN, AND IS BEING LOCKED IN PLACE.

The necessary tree information is:

1. *Tubing size and weight* - this determines seal element size.
2. *Tubing hanger ID* - Hanger ID may be slightly smaller than tubing ID and can affect seal element selection.
3. *Height from top connection to center line of lower master valve* - This height determines the maximum mandrel length permissible.
4. *Distance from center line of lower master valve to top of the production tubing* - This distance determines the tool stroke length required.
5. *Top connection* - This permits selection of the proper wellhead adapter.

With this information, a tool assembly can be delivered to location ready to install. A recommended installation procedure is as follows:

1. Close the master valves of the tree.

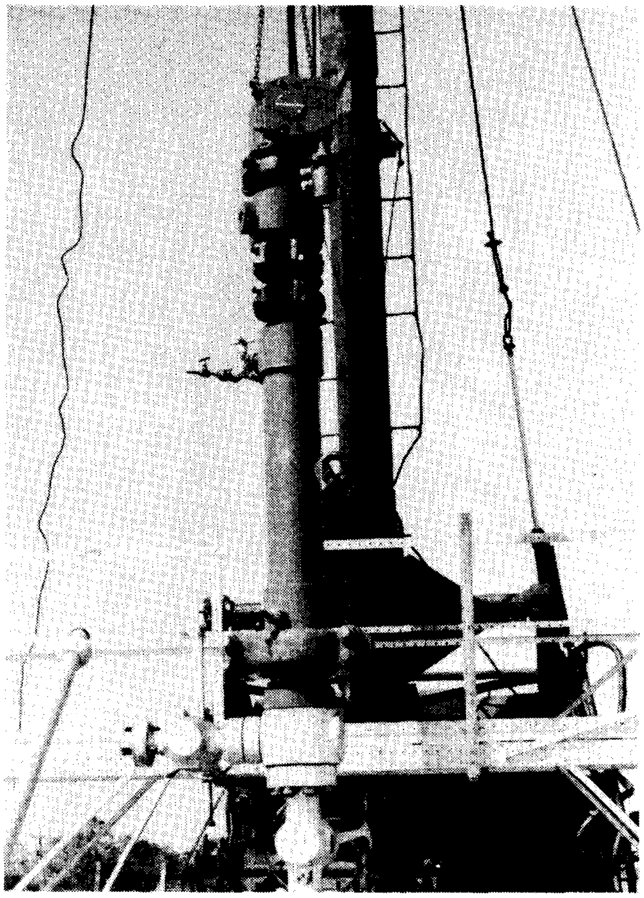

FIG. 5—INSERTION IS COMPLETE. THE MANDREL IS LOCKED DOWN, THE WING VALVE HAS BEEN OPENED TO SET THE SEAL ELEMENT. THE NEXT STEP IS TO CONNECT PUMP DISCHARGE LINE AND PROCEED WITH THE TREATMENT.

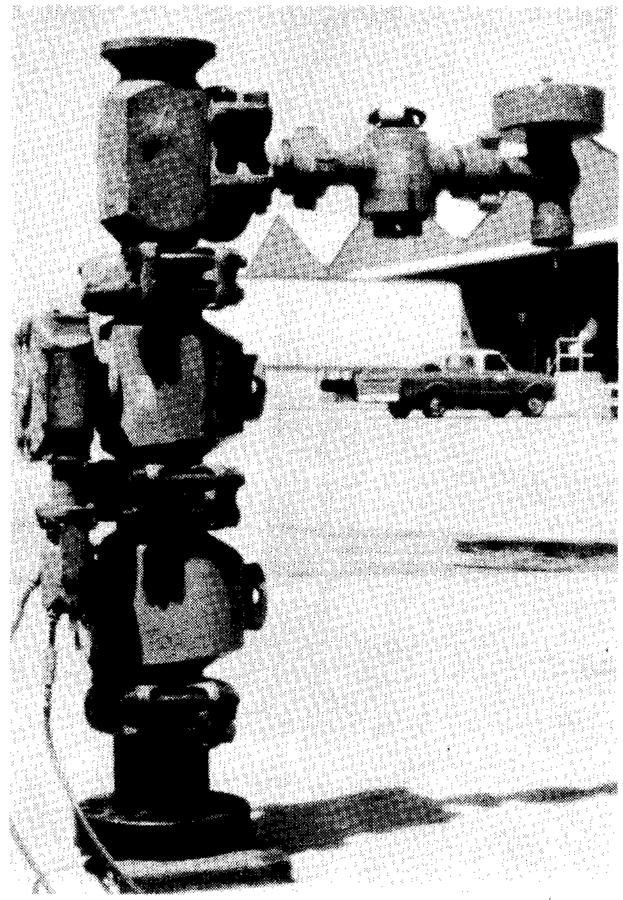

FIG. 6—THIS IS A 20,000 PSI WORKING PRESSURE 2-9/16" BORE UPPER RUN ASSEMBLY READY TO BE INSTALLED. IT INCLUDES A HIGH TENSILE STRENGTH ADAPTER FLANGE WITH 10,000 PSI FLANGE DIMENSIONS; ONE MANUAL, AND ONE REMOTELY OPERATED VALVE; WING VALVE; AND A 20,000 PSI PNEUMATICALLY OPERATED CHOKE.

2. Disconnect flow line at choke.
3. Open wing valve and upper master valve, leaving lower master valve closed. Check carefully for leakage. If the lower master valve is leaking appreciably *do not* attempt to install the isolation tool.
4. Remove swab valve or tree cap at top of flow tee. Connecting the tool directly to the flow tee minimizes overall height, and reduces the number of potential leakage points to a minimum.
5. With the tool piston fully stroked up, set the tool assembly on the tree and connect at the flow tee. Have valve on top of tool open. See Fig. 2.
6. Connect pump to the wing valve and pump slowly until tree bore and tool mandrel are completely filled with liquid. The seal element will not set while pumping this direction.
7. Close valve on tool and pressure-test to working pressure rating of tree. See Fig. 3.
8. Open lower master valve with pressure differential toward the tubing. This helps insure that the seal element cup is not energized.
9. Start insertion by pumping slowly on top of the piston. Observe insertion pressure closely; if any sharp increase in pressure is noted, stop pumping immediately as the cup has started to seal or has encountered mechanical interference. Attempting to force the seal element down will probably damage it. Pump slowly through the wing valve to relax the cup and reduce it to the

minimum OD. Resume pumping on top of the piston. If resistance is still noted, rotate the mandrel slowly clockwise. Occasionally, flange faces are not pulled down exactly parallel which results in a crooked tree bore. Rotating the mandrel will usually find a free path.

10. When the mandrel is fully down, mechanically lock it in position. *Never* depend solely on hydraulic pressure to hold the mandrel in position. See Fig. 4.
11. Disconnect the pump from the wing valve. If the well has pressure on the tubing, the packer can be set by opening the wing valve, which puts a differential pressure across the seal element. See Fig. 5.
12. Leave the wing valve open during treatment. Watch carefully for leakage. Leaving the valve open puts maximum differential on the seal element helping to insure a better seal, and in the event of a sudden failure, provides a release to help prevent over-pressuring the tree.
13. When treating is completed, and the tool is to be withdrawn from the tree, reconnect the pump to the wing valve and pressure up on *top* of the seal element to slightly more than the tubing pressure. Reducing the pressure differential permits the seal element to "unset" and helps prevent tearing it up, which is often the result if the mandrel is simply unlocked and withdrawn.
14. Tubing pressure will ordinarily force the mandrel out of the tree bore, and the rate of withdrawal is controlled by regulating the release of fluid from the top side of the piston.

The simplicity and economy of isolation tools make them ideal for breakdown treatments, and they are used to good advantage on fracturing jobs. They are also abused on some fracturing jobs. Sand-ladened fracturing fluids are very erosive at high velocities, and care must be exercised when using these tools on fracturing treatments.

The bores of the mandrels are necessarily small. The OD of the mandrel is limited by the tubing bore, and the mandrel wall must be relatively thick to withstand high treating pressures.

Erosion rates vary considerably with different fluids, but a working guideline is a maximum safe velocity of 250 feet per second. Mandrel erosion will occur at this velocity, but at a relatively slow rate. A very large treatment volume could be run with acceptable wear if one started with new mandrels. Mandrel erosion rate will increase at roughly the cube of the velocity above 250 fps, which will sharply limit the pumping duration permissible.

At velocities above about 300 fps, the extreme turbulence at the abrupt exit of the mandrel can begin to erode the tubing body. Erosion tests and job experience have indicated that tubing erosion is very slight (0.0005 in. to 0.001 in. per hour of pumping) with efficient mandrel exit shapes at velocities up to 250 fps. Above 300 fps, tubing body erosion becomes quite noticeable, and at 350 fps, tubing can be severely damaged in a one-hour span.

Again, it is emphasized that fluid properties very much affect mandrel erosion rates in the velocity range up to 300 fps. Mandrel and tubing wear might be acceptable with some fluids at 300 fps and totally unacceptable at the same rate with another fluid. Generally, the higher the friction loss of the fluid, the higher the erosion rate.

Sand concentration has little discernible effect above about 1/2 ppg; or conversely, 1/2 ppg will erode almost as much as 2 ppg.

The 250 fps guideline limit mentioned above is a generalization, and is recommended as a working maximum unless a very particular and carefully controlled set of conditions is known. A more convenient expression of the 250 fps velocity guideline is:

Mandrel ID (inches)	Rate at 250 fps (BPM)
0.90	11.8
1.00	14.6
1.10	17.6
1.25	22.8
1.50	32.8
2.00	58.3

The wellhead isolation tool is an economical and useful tool for upgrading working pressure limits of well systems for many stimulation requirements. No work is required on the wellhead-tubing system to install it, but it should always be applied with the prudence and care any "live" well deserves; and treating conditions should be designed within the tool's limitations.

TREATING TREES

In some instances, treating requirements may be beyond the safe operating capabilities of wellhead isolation tools. Changing out Christmas trees becomes the next alternative.

This can be quite expensive on deep wells when a large workover rig is required to lift the tubing; in many cases weighted fluids are necessary to kill the well and severe formation damage may result. Special parts for the tree assembly may be required, and in a final analysis, the whole prospect may become questionable.

One possibility on certain tree assemblies is substituting *only* an upper run assembly of a higher working pressure than the production tree. This would require setting a back-pressure valve in the tubing hanger and/or wireline plugs downhole, then removing the upper run of the tree at the tubing hanger adapter flange or bonnet, and substituting a higher pressure upper run. This will result in a flange mismatch, and a changeover spool, or adapter, will be required. In addition to making a dimensional adjustment for different flange types, the attachment of the adapter to the top face of the bonnet must be modified. For example, if a 15,000 psi upper run were to be substituted onto a 10,000 psi production tree, a spool from the 15,000 psi bottom flange of the master valve to the 10,000 psi configuration on the top face of the bonnet would still only be a 10,000 psi rated connection. Either the bolt size, or strength, must be changed to appreciably increase the effective pressure rating. Changing the size is not practical, but changing bolts is no problem.

By substituting indicator bolts with a minimum yield strength of at least 120,000 psi *and* making sure that the makeup stress in each bolt is at least equal to the effective pressure, the holding capability of a standard flange connection is increased 50 percent; in this example, from 10,000 psi to 15,000 psi. Torque measurements at these stress levels would be very inaccurate due to variations in thread friction, and a direct measurement of bolt strain would be more reliable.

In short, this substitution would require a special changeover spool for adapting valves to the tubing bonnet, the lower flange being thicker than standard; high tensile, indicator-type flange bolts with ground threads; and high-pressure valves with flow tee assembly. See Fig. 6.

Once installed on the tree, the plugs would be pulled, leaving the well ready to treat.

Following treatment and testing, the tubing could again be plugged to remove the "treating tree", and the production tree reinstalled.

While this technique is not as convenient nor economical as the wellhead isolation technique for temporary pressure upgrading, it would be preferred for high-rate, large-volume treatments that are beyond realistic limits of the isolation tool.

TOP OUT JOINTS

High-pressure stimulation work done through work strings while the drilling rig is on the well is often plagued by poor surface pressure integrity. The few feet of pipe above the blow out preventers and especially the top connection, comprise the fundamental working pressure limitation.

That portion of the tubing below the BOP can be supported by annulus pressure and differentials reduced, but that part of a joint above the BOP has to withstand the full treating pressure. In addition, it may be subjected to bending and torsional loads. Heavy-weight and/or high-tensile tubulars are often procured especially for this location in the string, and may be totally competent in the pipe body, but very little can be done to insure a threaded connection holding throughout a long treatment.

Typically, the threaded connection immediately under the tubing valve causes most shutdowns. Not only is this connection subjected to the highest pressure differential in the string, but high-frequency pump vibrations transmitted through the discharge line tend to loosen it. This connection is, by all odds, the weak link of the tubular chain.

A simple solution to top connection problems is effected by making the top connection an integral part on heavy-wall tube. A flange or hub-type connection is not affected by torsional loads or vibration.

This special joint must be long enough to extend through the BOP, adapt to the work string, and have a lift shoulder on top for elevators to pick up against. See Fig. 7.

Anticipation of need for, and the procurement of, is the main effort required to utilize the "Top Out Joint". Installation in the string is identical to the joint of pipe and, at most, preventer ram size may have to be changed.

Figure 8 illustrates one version of the "Top Out Joint". This tube is 3 in. ID and 5-1/2 in. OD, 20,000 psi working pressure, with clamped top

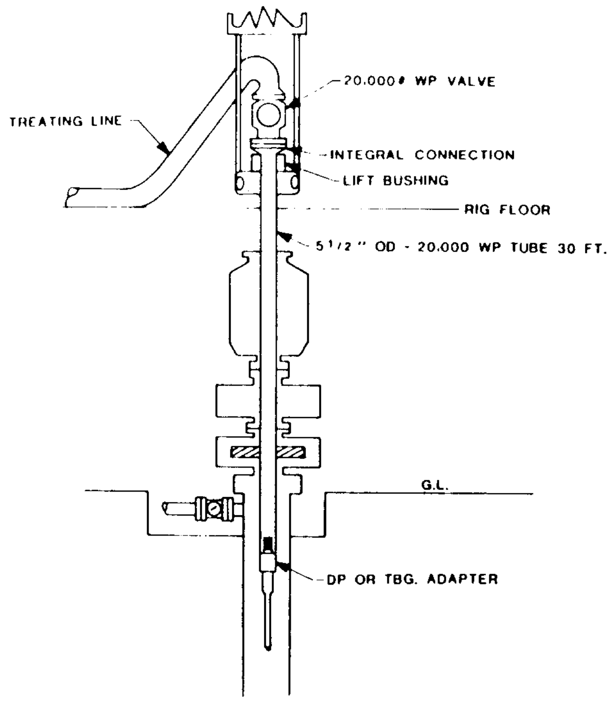

FIG. 7 —ELEMENTS OF A TOP OUT JOINT ASSEMBLY.

connection, lift bushing, and an O-Ring sealed, adapter-type bottom connection. Pressure integrity of this type surface connection is several fold greater than conventional threaded-type connections, and mechanical problems are virtually eliminated.

SUMMARY

Most surface equipment working pressure ratings can be safely and reliably upgraded by one of the three methods discussed here.

Pressure upgrading permits more latitude in designing and performing stimulation treatments, and often means the difference between a marginal result and a resoundingly successful one. These techniques are not just applicable to high pressure work; the 15,000 psi and 20,000 psi working pressure

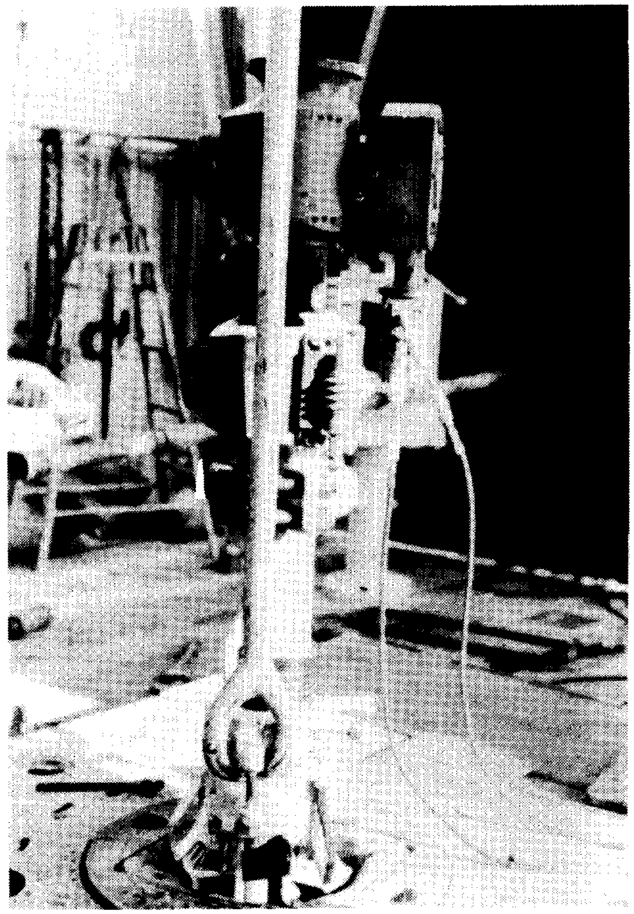

FIG. 8 —TOP OUT JOINT COMPLETE WITH DOUBLE 15,000 PSI WORKING PRESSURE, 3" I.D. VALVES.

ratings are mentioned in this text only to illustrate capability. Most isolation tool work for example, is done through 3000 psi and 5000 psi rated trees installed on older wells.

The cost of this equipment and the installation time required for these upgrading procedures is minute in comparison to the possible injuries, damaged equipment, and the cost of aborted treatments that can result from exceeding rated working pressures.