Tubing Anchors — Should We Use Them?

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Is your company likely to have worn tubing couplings, or holes worn in the casing caused by tubing movement in the next few years? Are the tubing threads, or even the body of the tubing likely to break by repeated stresses of transfer load? Do you think that there is likely to be a loss of efficiency in pumping due to movement of the tubing at the pump end? Could it be possible that a low pump efficiency could be due to the leaky thread in the tubing, resulting from the tubing threads working?

If the answer to any one of these questions is "Yes," then it is entirely possible that you should use tubing anchors. Therefore, an endeavor will be made to throw some light on this subject.

Some ask, "What is a tubing anchor?"

A tubing anchor is a tool placed in the tubing string, either approximately 20 percent above the bottom end of the tubing, or at the end, or near end, of the tubing. It is placed there to prevent movement of tubing while pumping or flowing.

There are several types, such as "Hook wall" (incorrectly referred to as compression type), and tension type.

Hook Wall Type Anchors

The hook wall type anchor is set by rotating in the right hand direction to release the slips so they will engage with the casing when the tubing is lowered. The slips will hold the 20 percent of the tubing below, and thus relieve the upper part of the tubing from that much load. Also the load transferred from rods to the tubing will be taken only by the anchor and casing.

Tension Type Anchors

Tension type anchors are those which can be set below a determined point and then the upper end of the tubing stretched upward until it can be set on slips, or other devices of the well head.

There are several types of these anchors. Some have a screw mechanism to set the slips and retrieve them. Some have a frangible mandrel which is broken in the event the tool cannot be retrieved correctly. However, this leaves material in the hole which must be fished out.

Another type tension anchor is one that is set as the others, by rotating one direction and retrieved after turning in the other direction.

In the event this rotation is not successful for retrieving, then it is only necesssary to pull on the tubing some extra weight to fracture the frangible slips. These slips are a new concept of friction. They are not held to the body by dove tail slides, but by a flange on the sides which move in a sloping groove in the body on each side of the three slips.

In reference to an A.P.I. publication, given in Chicago, Illinois, November 5, 1951, entitled, "Influence of Tension and Compression on Straightness and Buckling of Tubular Goods in Oil Wells," by Arthur Lubinski, Research Department of Stanolind Oil and Gas Co., Tulsa, Oklahoma, we find application of these calculations for actual field uses.

For example, the paper refers to tubing set on a packer, and the packer is called the "freeze point." Figure 1-A. If there is not fluid inside, or outside, the tubing then some compression will cause buckling, as shown in Figure 1-B.

If the tubing is subjected to fluids above the packer in the annulus, the paper shows that the tubing could take some compression without buckling, due to external forces tending to keep the tubing straight. Also if the tubing is on the packer and no fluid in the annulus, but there is fluid inside, then the freeze point should be subjected to some tension to prevent buckling, or to keep the tubing straight.

For lack of time the mathematics and explanation will be accepted, and those wishing to follow the calculations may obtain the above mentioned paper for thorough investigation.

Let us take the first example of the freeze point and use the "hook wall" anchor instead of a packer. Referring to Mr. J. C. Slonneger's statement in the paper, "Principles of Sucker Rod Pumping," given at the 1954 West Texas Short Course in Oil Lifting Methods, "The tubing anchor should be set with approximately 20 percent of the tubing below the anchor." If the anchor is set without any fluid inside, or outside of the tubing above the anchor, and only that weight of the 20 percent of the tubing load below the anchor is lost from the entire string, the tubing will hang straight until a load of fluid is pumped up through the tubing. When the tubing is full, some amount of buckling could occur. Fig. 1-A-B.

If the second instance is used, from Mr. Lubinski's paper where there is a hole full of fluid, and the anchor is set, it might be thought that a little added weight might be all right, due to annulus load. In this case it would be all right to add the load if the annulus fluid remained at the same level. In most cases the fluid level is lowered, and as this occurs the buckling would then have a chance to occur and result in an expense to pumping.

In the third instance of the above paper where the hook wall anchor is set, knowing you will fill up the tubing, then the anchor should be set with a loss of load equal to less than 20 percent of the tubing string. This would leave the upper part of the tubing in tension and would have a tendency to eliminate the buckling.

Unfortunately, placing the hook wall tubing anchor 20 percent above the end of the tubing does not eliminate the movement of the lower end of the tubing. It is still free to thresh about.

Present knowledge of tubing troubles resulting from unanchored tubing may be reviewed at this time. The "Drill Bit" magazine published an article in February 1955, entitled, "Correct Uses of Tubing Anchors Gives Advantages, Cuts Servicing Required." (Reprints may be obtained from Equipment Engineers, Inc., Dallas, Texas.) This article discusses load changes on the tubing due to rod pump picking the load up off the tubing on the up stroke, and dropping this load on the tubing on the down stroke. (The article deals with hook wall tubing anchors only.)

This load could vary from a few hundred pounds to 15,000 lbs. or more per stroke. In a well making 10 strokes per minute, this changing load would occur 5 1/4 million times per year. It is easy to see that the tubing fibers are stressed in proportion to the strokes per minute and the load on the plunger. Also, the threads are going to jerk out of the coupling or at least attempt to come out of the coupling on each stroke. The only thing that prevents the joint from jumping out of the coupling is resistance of the joint to neck down enough to pass the threads, or the lack of stretch in the diameter of the coupling from enlarging in diameter so that the threads will come out. See Fig. 3-A.

This action results in the threads of the coupling, and the threads of the joint, moving up and down on each other, vertical to axis of the joint, and in time, with millions of movements per year, laps or hones each other away until the threads do not fit close and therefore leak. See Fig. 3-B-C.

This leakage is not noticed and often attributed to the well falling off in production.

Many times producers have found the well's production extremely low, and moved in to check the equipment. If they found nothing wrong with the pump, they then pulled the tubing. If they found nothing wrong with the tubing, they "gave up," and ran all the equipment back into the hole. To their surprise the well's producing capacity is increased, but they did not know why.

The threads, when replaced, have a new coat of compaund and are made up into the coupling a couple of threads more. Also the old coat of scale which was deposited at each end of the threads is now jammed together tightly. This serves to eliminate the worn places and makes a new seal. See Figure 3-D.

In a well near here, the production fell off too fast and an effort was made to analyze the cause. A Dynamometer checked the pump O. K., but no fluid came to the surface. A testing service was called to check the tubing for leaks, and found that fifteen of the top collars were leaking. These collars were replaced, and the production became normal. A number of other wells which had been operating six or seven years without pulling

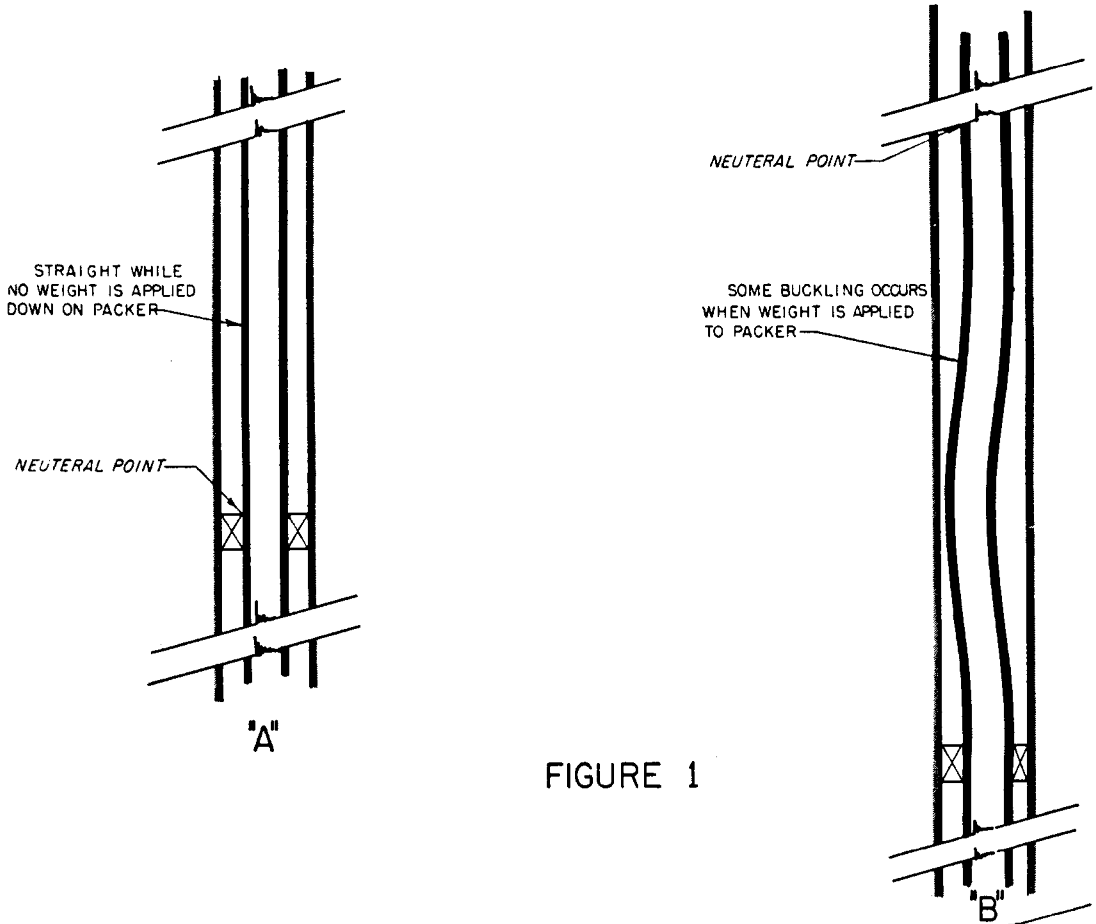


FIGURE 1

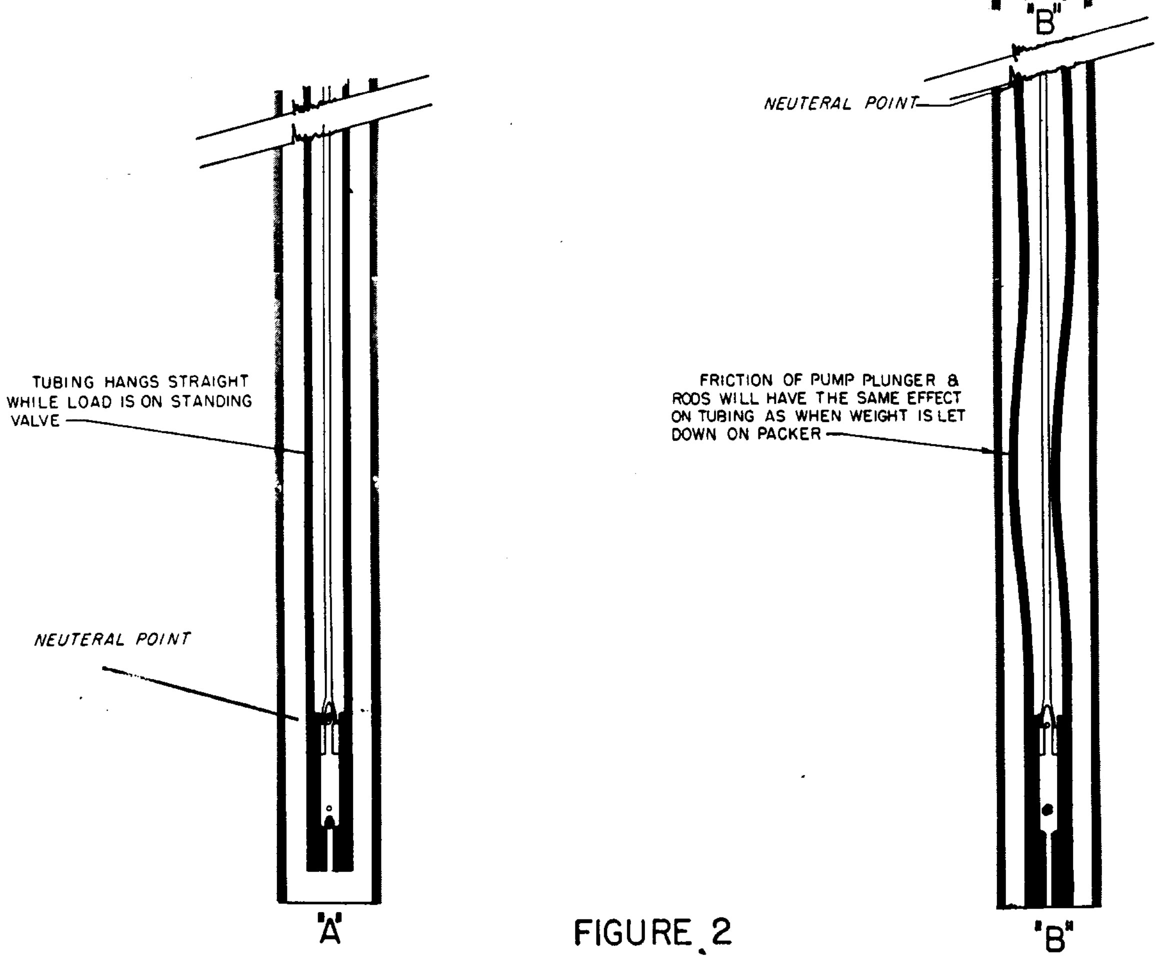


FIGURE 2

were checked, and found to be leaking badly. Whereas, these wells had been operating 24 hours a day to obtain their allowable, they now produced the allowable in six hours. Electricity, wear and tear on equipment, loss of production, etc., would easily have paid for a tubing anchor.

In wells where the shock load is 10,000 to 15,000 pounds per stroke, the cross section of the tubing is being stretched as a sucker rod with a large range of load. This range of load is detrimental to the tubing, and causes internal stress, resulting in cold working of the steel. This cold working increases the hardness and causes brittleness. Hardness reduces the life or elastic limits of the tube.

Tubing load changes were found to be excessive when pounding fluid. A test was made in a well which would pump down.

In Figure 4, cards A and B were taken on the rods and the tubing at the same time. The well was pumped at four different speeds. The first of which would not pump the well off, the other three speeds pumped the well off in varying degrees, until the

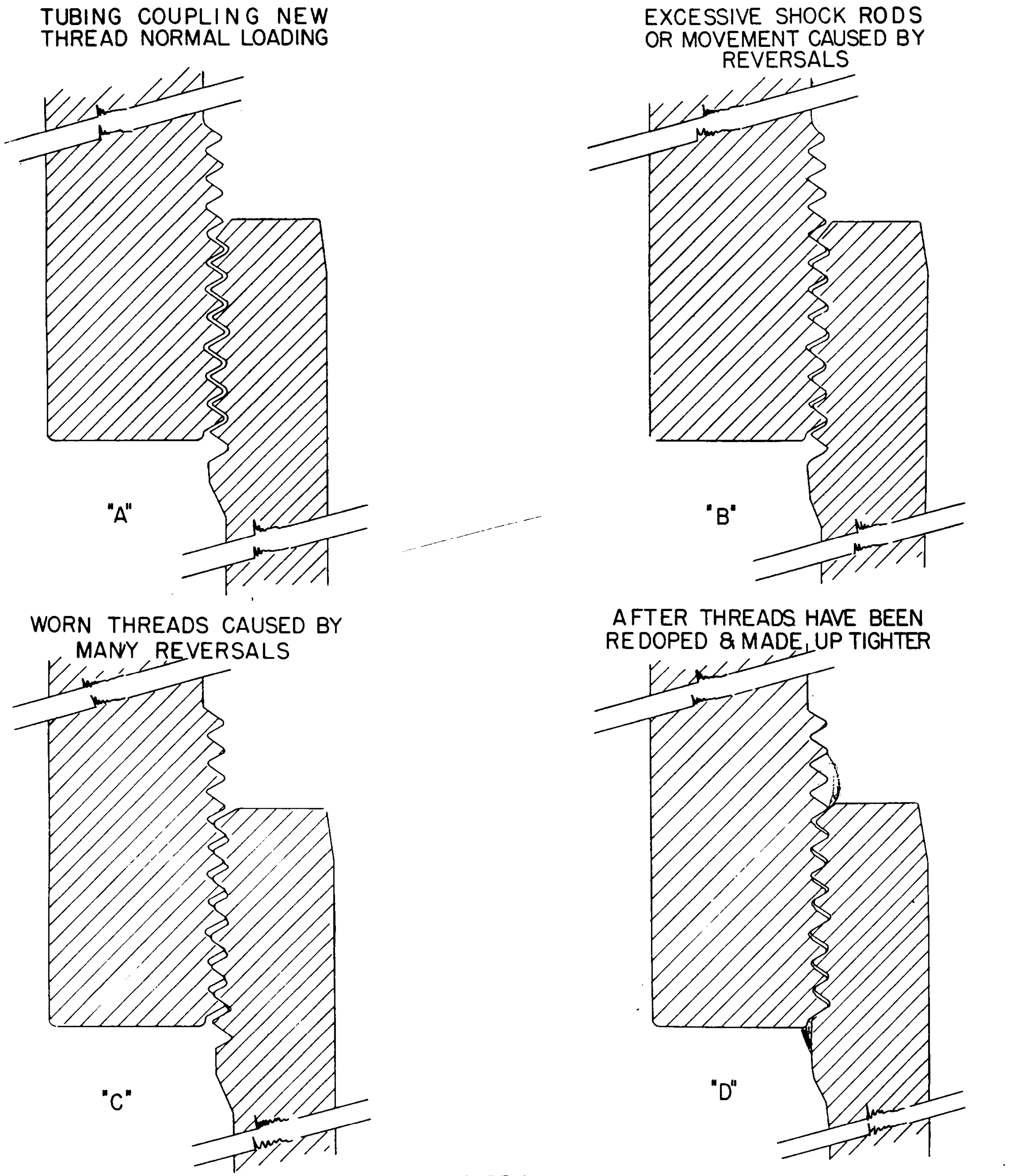


FIGURE 4

fastest speed pounded fluid below the half way mark on the down stroke. It can be noted how the range of load on the tubing, increased with each increased speed and a higher velocity of impact on the down stroke.

A tubing anchor was later run into the well, and a similar test taken at similar speeds with the same equipment. (Fig. 4). Cards A and C were the results in this case.

It is evident that the range of load on tubing has been reduced to nothing. This elimination of range of load reduces cold working and hardening, and extends the life of the tubing and threads to approach an infinite time. Even though wells which pump in a normal manner and then have a tubing anchor installed, benefit from the reduction of range of load to zero.

In pumping a well the plunger picks up the load on the up stroke, and the tubing is relieved of this stress and tends to follow the plunger up for some distance. This distance varies with the speed and the length of the stroke and diameter of the plunger.

Recently a tension type anchor was installed in a deep marginal well, to aid in relieving tubing trouble. The well now makes more oil per day with less pumping time. In this well the plunger is having a higher sweep through efficiency. The saving in equipment life will pay the anchor out quickly, to say nothing of increased production with less electricity.

Another well had a large plunger running at a high rate, and producing about 580 bbls. per day. The equipment had difficulty staying together at this speed. A hook wall anchor was installed. The tubing plunger load was so great the hook wall tubing anchor could creep up the hole and cause buckling. This anchor was removed and a tension tubing anchor was installed. No other equipment was changed.

In the next eight months there were no service unit jobs on this well, or an elimination of 16 over the previous eight months. The engine maintenance had become almost nil. The production had increased to 750 bbls. per day.

In this case the well made a profit before the troubles were corrected. Now the margin of profit is almost double. This is the case in many instances after the tubing anchor is properly used.

It is not often that the friction of the plunger and rods are considered in a pumping well. This friction is considerable and will cause some buckling on the up stroke, Figure 2. This buckling will occur in the lower end of the tubing. If the hook wall anchor is used, the lower 20 percent of the tubing will dangle below, and the friction will cause some buckling below the anchor. If the tension type anchor is used, and set at the bottom end of the tubing, there should be no buckling.

Often in deeper wells we find worn tubing and rod couplings at the lower part of the tubing. Many operators pass this off as crooked hole, and think they can do nothing about it. In this day of drilling, it is too expensive to drill crooked holes, and it is unlikely that they should exist to an extent to cause rod wear. By installing tubing anchor in that type well, it is entirely possible to eliminate such excessive wear. This wear shows up, also, in additional horsepower required.

Some people might be disturbed about the tubing being stretched more than hanging with the fluid load in the well. For a moment, let us think about a sucker rod joint. Here we make up the pin and coupling tightly enough to stretch the pin beyond any load that may be applied to those rods. If the pin is not stretched to that point, the pin failures will be in the results.

The tubing should be placed in tension to prevent working of these collars and flexing the molecules in the body of the tubing. By looking at a Goodman's Diagram (one may be found on page 28 in the Sucker Rod Hand Book No. 336, published by Bethlehem Steel Company), we can see that the less the range of load we have, the more stress we can apply to the tubing and the closer we can approach the tensile strength in this work. Therefore, if we pulled enough tension in a string of tubing to overcome all forces of changing bouyancy, reciprocal loading and friction applied while pumping, the tubing would last longer and have less effect from corrosion, also less effect from work hardness. The collar threads would stay perfect without wear, except from the friction of unscrewing.

Some operators take the stand that anchors are good in wells of a certain depth, or deeper. This is a weak "out" in this problem. It should be looked at from the angle of load transfer, speed, and well conditions. Certain combinations of stroke length, speed and plunger diameter will cause tubing to move up and down the hole dangerously close to destruction.

The old saying "out of sight, out of mind" seems to apply to the tubing and casing problems. The top of the tubing does not move, so some think the bottom does not move. The casing cannot be inspected, except by expensive methods, so that problem will never occur, they hope. When the

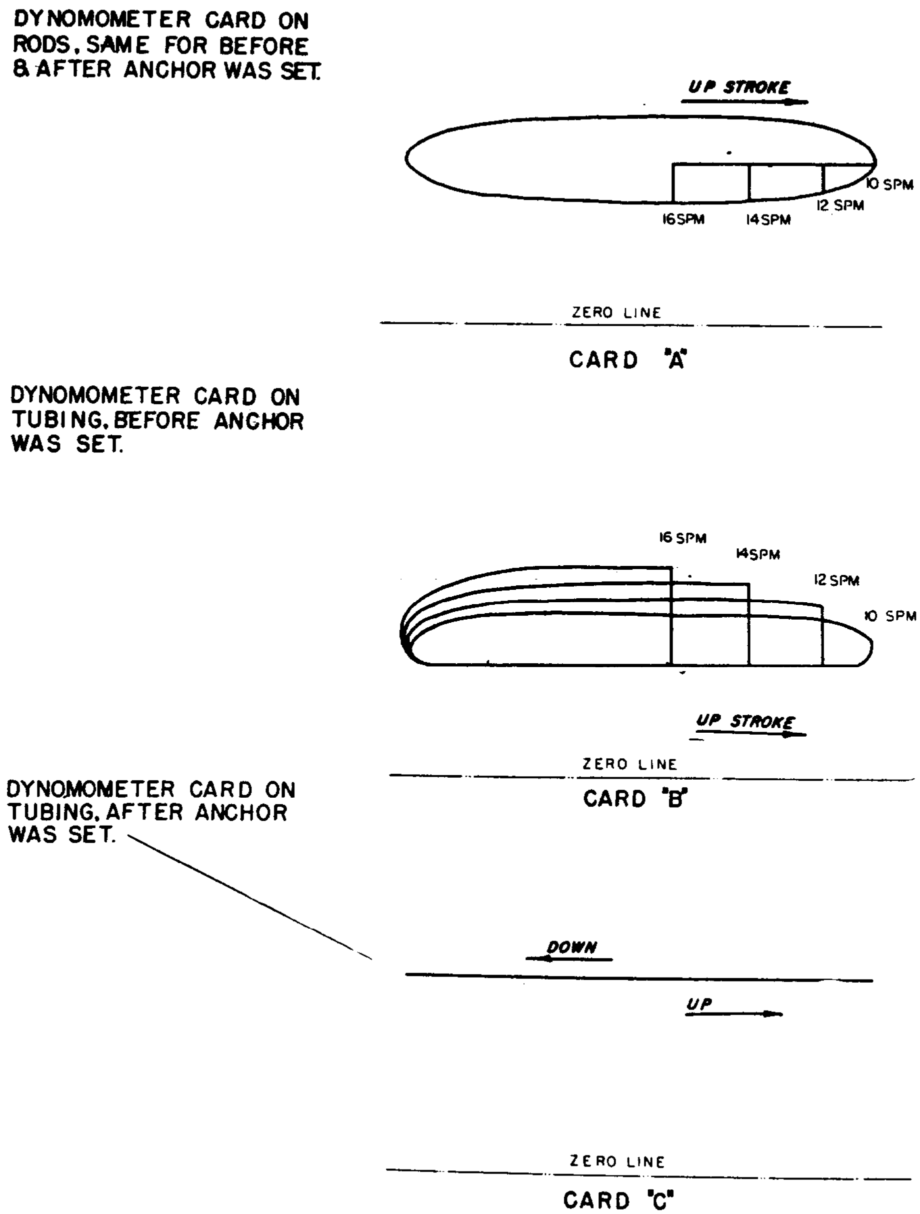


FIGURE 3

tubing couplings come out, worn only a little, there is evidence of casing wear. Unfortunately the casing cannot be pulled and replaced as simply as tubing.

The problems of moving tubing are many and varied. Here is an example of one problem with a hook wall anchor.

Dynamometer card No. 1. Figure 5, was taken on a well which had become destructive to the engine. This card was taken and demonstrated that the loads exerted were above normal, and that there was undertravel in the plunger.

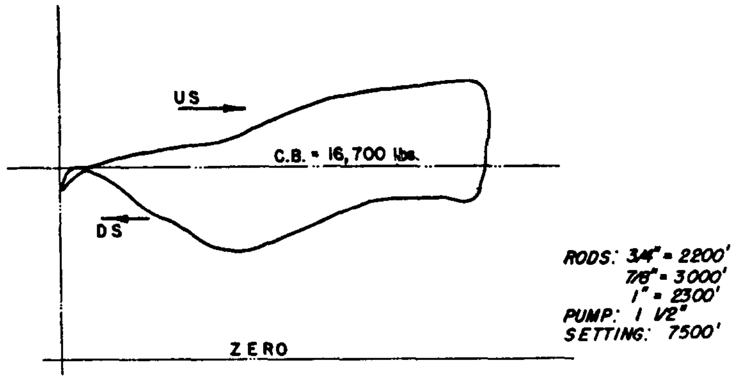
At this point the analysis disclosed excessive friction in the rod string due to the creeping up hole of the hook wall anchor.

One short pup joint of tubing was removed from the string and the card No. 2 was taken. It can be seen by the data along side the card that there was an effective benefit in the peak load, range of loads, rod stress and torque in the gear box.

Another pup joint was removed before card No. 3 was taken. This card indicated data almost identical to that taken when the equipment was first installed. The improved condition has a tremendous benefit in all parts

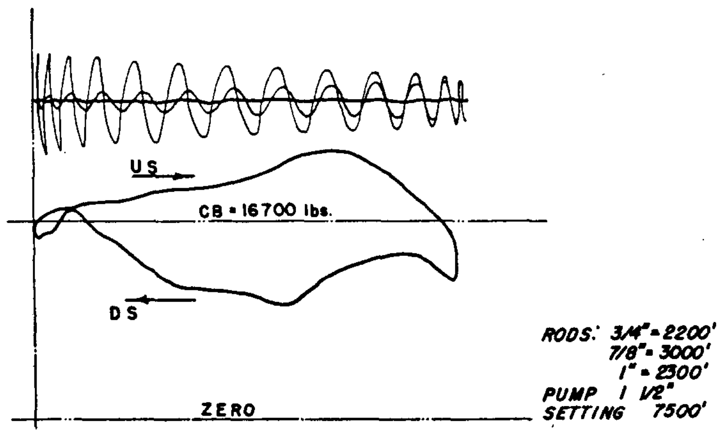
SOME BODYS NO. 1
THE OTHER DAY 12:18
SCALE: 8875 Lb./in.
MAX. LOAD = 23,650 Lb.
MIN. LOAD = 9,910 Lb.
RANGE = 13,740 Lb.
ROD STRESS = 30,300 Lb./in.^{2}
A. CARD = 3.56 in^2
L CARD = 4.15"
PRHP = 18.2
PEAK TORQUE = 258,000 in-Lbs.

CARD No. 1



SOME BODYS NO. 1
THE NEXT DAY 2:05
SCALE: 8875 Lb./in.
13-74" SPM
MAX. LOAD = 22,800 Lb.
MIN. LOAD = 9,470 Lb.
RANGE = 13,300 Lb.
ROD STRESS = 29,200 Lb./in^2
A. CARD = 3.09 in^2
L. CARD = 4.07"
PRHP = 16.35
PEAK TORQUE = 264,000 in.-Lbs.

CARD No. 2



SOME BODYS NO. 1
ELEVEN DAYS LATER
SCALE: 8875 Lb./in.
13-73.5" S.P.M.
MAX. LOAD = 20,600 Lb.
MIN. LOAD = 10,280 Lb.
RANGE = 10,320 Lb.
ROD STRESS = 26,400 Lb./in.^{2}
A CARD = 2.455 in^2
L CARD = 4.06 in
PRHP = 12.92
PEAK TORQUE = 198,000 in-Lbs.

CARD No. 3

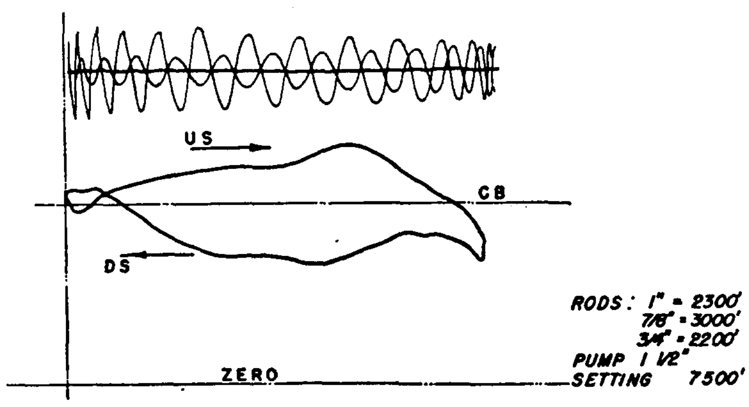


FIGURE 5

of the pumping system.

The tubing was pulled from the hole, and it was found that the anchor was set with less than 20 percent of the tubing below. The reason the anchor crept up the hole was that the plunger load, friction of plunger and rods, was greater than the weight of the tubing hanging below the anchor. On each stroke the lower end of the tubing would raise a little, and the anchor would also move up and catch a new hold, until it had buckled the tubing above. From discussion above we find that it is easy to buckle the tubing under certain conditions.

Most troubles in the past, and benefits from the new information, all point to keeping the tubing in tension in pumping and flowing wells.

The new developments have made them safer to use and remove. The benefits when viewed over a long period of time are tremendous of value.

The hook wall anchor, when properly used, keeps the majority of the tubing in tension, and is greatly beneficial. Some people have to become accustomed to anchoring tubing as a new idea, yet it has been anchored in many wells over a twenty year period by using hook wall tubing anchors.

To those wanting the ultimate in anchoring, the tension type anchor is the answer.

Yes, it can be said that tubing should be anchored.