The Lease Pumper's Handbook

Chapter 17
Well Servicing and Workover

Section C

THE TUBING STRING

C-1. Tubing and Casing Perforation.

The relationship of casing perforations to tubing perforations is important to the performance of the well, whether it is a flowing well or produced by artificial lift. The lease operator must know if the tubing perforations are above or below the casing perforations or at the same level (Figure 1). This can be critical as to how much oil the well produces and the problems encountered.

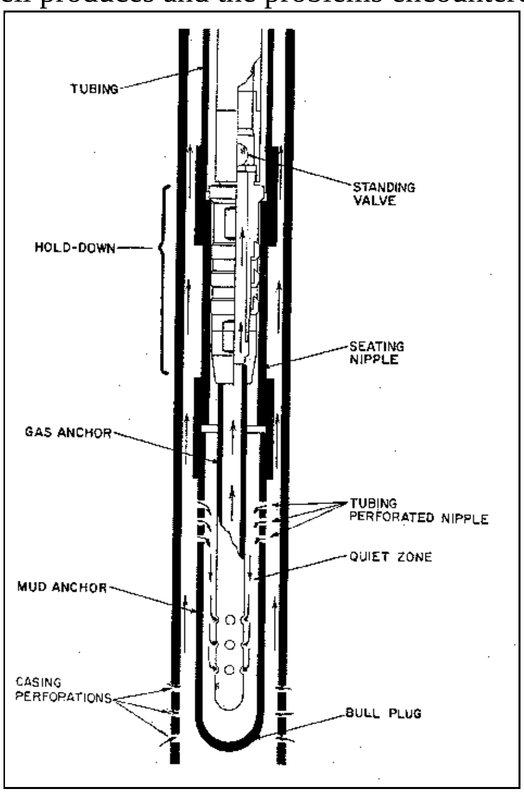

Figure 1. Relationship of well perforations.
(courtesy of Harbison Fisher)

For wells that produce a lot of scale, production personnel operate under different philosophies. One school of thought is that the higher the tubing perforations can be raised above the casing perforations and still achieve a satisfactory daily production, the less the scale will break out of the water in the tubing and flow line. Some companies raise the tubing perforations a few feet above the casing perforations, while other companies move them much higher.

Some operators maintain that if tubing perforations are placed even with or lower than the casing perforations, the reduction in reservoir pressure will increase daily production, resulting in increased income to solve the additional production problems.

Other companies place the tubing perforations below the casing perforations even if it results in a tubing arrangement where the tubing has no mud anchor. A shop-made two-foot perforated joint is used. The joint is closed on bottom and has dozens of ½-inch holes drilled into it. A collar is used to screw it directly under the seating nipple. This reduces the length of the pump gas anchor to one foot or less. Companies favoring this method maintain that it gives the highest daily average production.

The most typical tubing arrangement is to place the tubing perforations a few feet above the casing perforations. This maintains a small amount of liquid against the formation, instead of having a drained or dry matrix area at the bottom of the hole.

The lease pumper should know the company preferences, and a supervisor is usually able to provide this information.

C-2. Selection of Tubing Quality.

Tubing is available in many different wall thicknesses and qualities of metal. Typical tubing ratings include:

- **H-40.** This is the most economical tubing and is used on wells that are not very deep.
- **J-55.** Most medium depth wells use this tubing. It will be found in wells up to approximately 7,000 feet deep.
- **C-75.** This tubing is not quite as common but gives dependable service where pipe better than J-55 is required.
- **N-80.** This pipe gives very good service in wells to approximately 12,000 feet or more in depth.
- **P-105.** This is an example of the heavier duty pipe needed for wells that are drilled deeper, where high gas pressures are encountered.
- **Additional tubing ratings.** Additional classifications go from x-heavy line pipe on the lower end to 110, 125, 140, 150, and 155 on the upper end. With wells exceeding 20,000 feet, special pipe has been developed.

C-3. Tubing Lengths and Threads.

Tubing is an extruded seamless pipe that is sold in random lengths from 28-40 feet (Figure 2). It is measured with a hundredth of a foot tape. By joint selection, a string of pipe can be made up to any specific length. Pup joints are available in two-foot increments up to twelve feet long. A mark may be stamped on the outside a few feet from the end to show its quality rating. The stamping may be a simple H, J, C, N, or P. On used tubing, this stamped number may be located after cleaning with a wire brush.

Threads may be round or V-shaped, with 8 round serving as the standard thread today. Round threads are hot rolled into the metal and are much stronger than the older V-thread style. Changeover couplings are available when different threads are encountered.

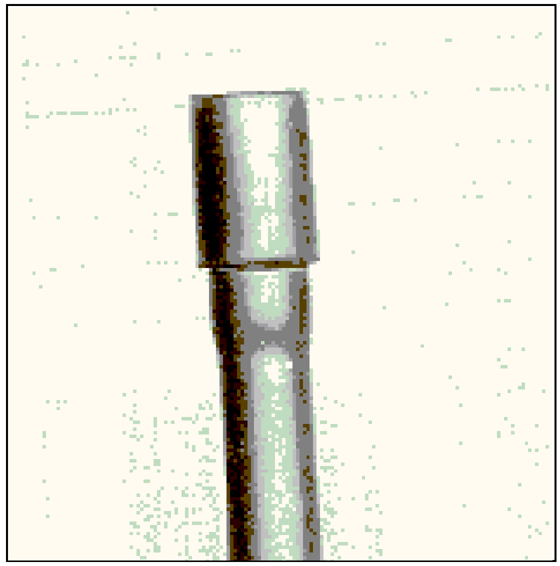

Figure 2. The end of a joint of tubing showing the upset end and the tubing collar.

C-4. Measuring Line Pipe and Tubing Diameter.

New oilfield workers sometimes have trouble understanding the sizes of pipe and should memorize the following two rules:

- Line pipe is measured by inside diameter because it is associated with production volume.
- Tubing is measured by outside diameter because this is the inside diameter of lifting tools needed to run tubing into the hole.

Pipe used on the surface for flow lines and for constructing tank batteries is usually referred to simply as *line pipe* and is always measured by *inside* diameter. For example, 2" line pipe has an inside diameter of 2".

On the other hand, 2-3/8" tubing has an inside diameter of 2", and an outside diameter of 2-3/8". When 2-3/8" tubing is used for flow lines or other high- or low-pressure applications on the surface, many companies will refer to the pipe as 2" line pipe in their records. This does not create a problem when joints are measured. Common sense will dictate if it is tubing being used on the surface because line pipe for oil fields is usually 25 feet in length and tubing is longer.

Line pipe and tubing comparison.

- 2-3/8 inch tubing is 2 inch line pipe.
- 2-7/8 inch tubing is 2½ inch line pipe.
- 3½ inch tubing is 3 inch line pipe.
- 4½ inch tubing is 4 inch line pipe.

Smaller tubing is also available with an inside diameter of ¾", 1", 1¼", and 1½", as well as streamlined special sizes. Other special sizes are reviewed in Appendix D.

C-5. Pulling and Running Tubing.

During tubing make-up, care must be taken that the correct power is applied. If the joint is made up too loose, it may leak, and, if too tight, it expands the coupling and damages the threads. When standing the pipe in the derrick, care must be taken to prevent damaging the threads.

Dropping rabbits through tubing. When running new or replacement tubing into a well, a *rabbit* is always dropped through the joint to be sure that it is fully open. A standing valve containing the no-go section can be used for this. This will identify scaled or out-of-round joints, because the rabbit will hang up and fail to fall through the joint. It is preferable to identify the problem before the joint is run into the hole.

Tubing is usually broken out and made up with hydraulic tubing tongs. For some work, mechanical tools such as *crummies* are used and are available on well servicing units.

The advantages to hydraulic tongs over hand tools are obvious. The desired torque can be dialed into the tongs' power settings and additional or less power is available on demand. Correct pressure when running pipe is an assurance that threads will not be damaged on make-up.

C-6. Identifying and Recording the Tubing String Components.

The mud anchor. The mud anchor is the first joint run in the hole. It is usually a full joint with a tubing bull plug on bottom. When the tubing is pulled, this joint will usually contain several feet of sediment, formation, or drilling mud and will be emptied. The mud anchor also protects the gas anchor on the rod pump.

Pipe length measurements. By joint selection, a string of pipe or group of joints can be made up to a specific length. This is especially important when spacing gas lift valves or adjusting the total string length.

Perforated nipple. The perforated nipple may be two, four, six, or more feet long and is a pup joint with many rows of approximately ½-inch holes drilled through all four sides. Special combination mud anchor/perforated joints may be shop-made. The coupling or collar that connects each joint of the tubing string together must be of equal or better quality than the tubing.

Seating nipples. A seating nipple is a short joint of upset thickness tubing that has a tapered opening at either end to allow the pump to seat into it and seal the opening between the pump and the tubing.

Seating nipples are only long enough to seat the pump as long as the seat will hold. For cup-type seating pumps, it is less than one foot long. A longer seating nipple is available that is long enough to be reversible. If the seating surface becomes scratched or damaged, it can be turned upside down and a new seat is available. Mechanical-type seating nipples may not be reversible.

Packers, holddowns and safety joints. Records must contain specific information about special equipment that may have been installed such as packers, holddowns, and safety joints. This may be brand, model, serial number, method of how to set the tool, and how to release and remove it. For example, if a 25-year-old tool is removed, fished, run, or re-dressed, records are needed that must supply identifying information

The tubing string. Tubing is a random length string of pipe with each joint measuring from 28-40 feet long. When measured, the tally sheet must indicate if it is measured overall or with the 1½ inches of thread left off. This changes the measurement of the string length by 15 feet per 100 joints. The third and most accurate method of measurement is taken when pipe is hanging from the elevators, measuring from the top of the collar to top of the next collar with the slips removed. This gives the installation length.

When loading the string from the storage yard, some companies measure the pipe overall, including thread, but remove the thread measurement when running it into the hole for perforation correlation reasons.

If the string has problems and is being removed after many years, the pumper needs to know exactly what comes next and have an exact description. For this reason, pipe is always run back into the hole in the same order that it was removed.

Pup joints. When all of the full-length joints that can be run are made up, the final tubing spacers added are pup joints. Pup joints are available in two foot increments from 2-12 feet long. One and one-half foot as well as three-foot joints may be available. As many pup joints as necessary will be added until tubing perforations are at the correct depth in relation to casing perforations.

Wellhead hangers. The final item added in the tubing string is either the tubing hanger or the slips, according to the wellhead style. Another final act is to set the packer or latch onto the tubing holddown to prevent tubing breathing. It may also be necessary to pull a tension on the tubing.

C-7. Typical Tubing Problems.

Typical tubing string problems include split collars, holes caused by corrosion, and split tubing (Figure 3). With such problems, a well may stop producing fluid, even while showing good pump action from the bleeder.

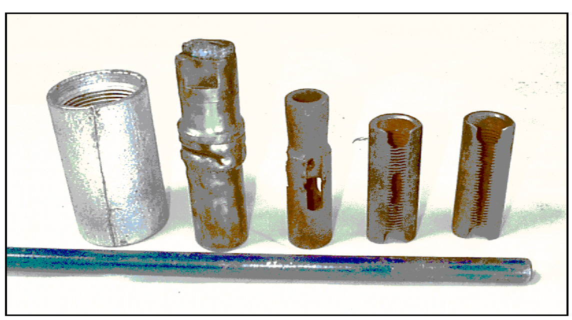

Figure 3. A split collar, damaged brass pump part, corrosion damage, and two worn sucker rod boxes.

Leaks or production problems can also be confirmed by placing a pressure gauge in the bleeder valve, closing the wing valve, and pumping against a closed-in system. This procedure needs to be coordinated with two people, with one standing at the electrical switch or clutch and the other observing the gauge. This procedure can also clear debris out of a pump valve. For safety reasons, the lease pumper should never stand directly in front of a gauge when it is being pressurized.

Split collars and holes in tubing. These problems usually result in no production at the bleeder and are relatively easy to locate. A typical solution is to mix a small amount of tracer material such as aluminum paint in five gallons of diesel fuel or kerosene, and pour it down the tubing. As the well is pulled, the leaking joint can be identified by observing the tracer material or aluminum paint on the outside. After identifying and replacing the leaking joint, the pipe is run back into the hole, and the well placed back into production. Normally only one hole will be found.

Standing valves. A standing valve can be dropped into the tubing to seat in the pump seating nipple in situations where the hole in the tubing is difficult to locate. The hole is filled with fluid, pressure applied at the surface, and the tubing pulled. When fluid is reached or the tracer fluid is observed, it should be possible to locate the hole or split joint.

After the problem has been solved, the standing valve can be retrieved with the sand line and an overshot, then the pipe can be run back into the hole and the well placed back into production. A good standing valve such as the one shown in Figure 3 will allow the pumper to release the fluid weight before having to unseat it. This reduces the pressure needed to unseat it.

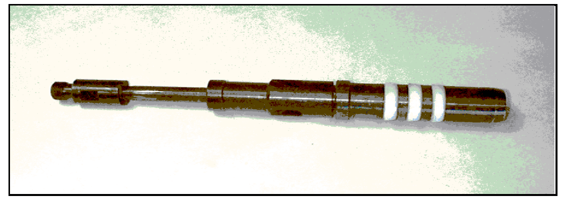

Figure 4. A 3-cup standing valve from Harbison Fischer.

Split tubing and hydrotesting. Occasionally a split joint of tubing can be very difficult to locate. Oil may or may not be produced. The bleeder valve may show good production, but no liquid travels to the tank battery. A standard pumping flow line pressure check at the bleeder valve can confirm the possibility of a split joint. If monthly flow line pressures are not taken and recorded, the pumper cannot know what the pressure should be. Consequently, there is no basis of reference to identify a problem in this manner.

When all other methods of locating the tubing leak fails, one option remains. The tubing can be hydrotested. When hydrotesting, the full tubing string may be pulled and two joints tested at a time under high pressure as the tubing is run back into the hole. A special two-person crew and a specially equipped truck are brought to the lease. Three sucker rods are used to rig up the 75-foot long tool. As each “double” of tubing is dropped into the hole, it is pressure tested. The tool is pulled up each time, so is just below the slips while testing. It is considered too dangerous to the safety of the floor crew to test above the slips.

Many other methods may be used when trying to solve problems of poor production.