TUBING AND WELLHEAD INTEGRITY PRESSURE TEST

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ABSTRACT

When a hole in the tubing, (HIT) is suspected, then confirm the HIT with a tubing and wellhead integrity pressure test. If no fluid is produced to the surface, then the test may be performed by shutting down the well and pumping clean treated water into the tubing. Then the tubing is usually pressured up to 500 psi(g) and the pressure is held for a time period. If a hole is present, then the tubing pressure will quickly leak off. A collar leak can take much longer time to leak off. If fluid is produced to surface, then the typical procedure is to use the sucker rod pump to increase surface pressure by pumping against a closed valve.

If a sudden drop in production occurs, then a recommended practice is to pressure test the tubing, casing check valve, and tubing back pressure valve. High speed tubing pressure data acquired in conjunction with a dynamometer test provides the operator with enhanced troubleshooting capability.

Introduction

Economic conditions dictate that maximum efficiency be maintained in artificial lifted wells at all times. When holes in the tubing or leaky check valve occur then the production rate from a well decreases and efficiency becomes low. When a hole in the tubing is suspected, then a recommended practice is to confirm the HIT by pressure testing the tubing.

In beam lift applications acquisition of dynamometer load and position along with simultaneous tubing pressure acquisition provides a combination of measured data can be very powerful for troubleshooting. With the advent of high performance digital data acquisition systems a more complete analysis of pumping system can be performed. Simultaneous measurement of numerous dynamic parameters such as tubing pressure, motor Kilowatts, amps and volts, gear torque, polished rod position, velocity, acceleration and load, motor speed and unit's strokes per minute allows detailed analysis and troubleshooting of numerous rod pumping problems. Modern data acquisition systems provide the means to acquire data from many transducers simultaneously in order to undertake either simple or advanced analysis. Simultaneous acquisition of high speed tubing pressure further advanced the operators ability to understand, troubleshoot and optimize wells.

Wireless Pressure Transducer

The pressure transducer element is constructed of extremely corrosion resistant Elgiloy material and utilizes thin film sensor diaphragm technology. The thin film Wheatstone bridge is applied to the diaphragm using a physical vapor deposition process to form a tight molecular bond with the sensor diaphragm. This type of transducer is rugged, long lived and offers good accuracy over a wide range of temperatures. The Wireless Pressure Sensor is powered by long lasting rechargeable batteries and is the currently certified by UL and CSA for use in Class I, Div1 Groups C&D per UL913 and CSA 157 standards. The wireless radio transmission range is approximately 400 feet line of sight. The wireless pressure transducer also houses a thermistor that measures transducer temperature. The Wireless Pressure Transducer is installed on a well (**Fig. 1**) that is setup to pressure test the tubing and then pressure test the casing check valve. The pressure transducer can be easily re-zeroed at the beginning of each test. The pressure transducer and associated electronics have stability for measurement of better than 0.1-PSI resolution with a pressure transducer having a rating of 1,500 PSI. Even better resolution is available with a lower pressure range transducer.

Tubing and Wellhead Integrity Pressure Test

An integrity pressure test is a process in which the tubing and valves can be tested for leaks. A pressure test involves filling the tubing with liquid, sometimes by either calling a pump truck or a hot oiler to determine if water or produced fluid can fill the tubing to a desired surface pressure. This type of tubing pressure test may be done by shutting down the well (usually on the down stroke) and pumping clean treated water into the tubing. If the sucker rod pump can discharge fluid into the tubing, then the lowest cost and simplest method to pressure test the tubing in a rod pumped well is to use the sucker rod pump to pressure up the tubing; each pump stroke discharges of oil, water and gas into the tubing. In order to perform the pressure test the tubing must be sealed at the bottom of the tubing and sealed by one or more valves at the surface. At the bottom of the tubing the standing valve of the sucker rod pump provides the seal, for other forms of artificial lift a standing valve must be set below the suspected hole in the tubing or near the bottom of the tubing to provide the seal, a seal below a hole is required to perform the pressure test. The downstream flowline valve is closed to ensure the fluid being pumped will go down the tubing and NOT go down the flowline or casing annulus. The tubing is usually pressured up to 500 psig. If the pressure remains reasonably constant then there is no leak and if the pressure drops off then there is a leak in the tubing or a leak through one of the closed valves. When the surface tubing pressure will not increase or goes on a vacuum, then on occasion a liquid with dye or paint is pumped into the tubing, so the pulled tubing joint having a hole will be easy to identify by the presence of the dye/paint on the outside of the joint.

If a hole in the tubing is small and near the surface, then the water injection rate (barrels/minute) can often increase the tubing pressure to 500 psig. Normally when a hole is present, then the tubing pressure will very quickly leak off (30 seconds to a minute). A "collar leak" however will not leak off as fast. A single leaking tubing collar can take as much as 10 minutes to leak off 500 psig of pressure.[1]

A back-pressure regulating valve, BPV, on the tubing is sometimes installed in wells to prevent liquid from being blown out of the tubing. Tubing liquids tend to flow off, when poor downhole gas separation results in too high of gas flow rate into the tubing. Pump action stops when gas blows the tubing dry since there is no differential pressure acting across the traveling valve. Gassy wells can flow off[2] or "unload" the tubing if foreign material of some type becomes trapped between the ball and seat resulting in sticking the back-pressure valve open, allowing the high gas rate through the pump to unload the tubing. While pumping, a quick method to check for foreign material[1] is to screw in the stem of a BPV several turns and then shut the well's tubing/flowline valve and allow pump action to increase the surface pressure. Once the tubing pressure has increased to 300-400 psi, then open the flowline valve. If the back pressure valve holds the pressure, then the BPV's ball and seat are providing a seal and no foreign material is impeding the seal between the ball and seat. If after opening the flow line and the pressure quickly leaks off, then the back pressure valve should be disassembled and repaired.

Another "valve" that can leak is the surface casing check valve. There are many brands on the market, but most employ a flapper that shuts against a seat to only allow the casing fluid to flow in one direction - down the flowline. When a casing "check" fails, a well can have all the visible signs of normal pumping, even showing a back pressure valve that is operating properly. But a leak in the surface casing check valve can result in none of the produced fluids going to the tank. The well's production will be "circulating", where fluid that is being pumped up the tubing is leaking past the flapper and falling back into the casing annulus of the well. When a HIT or leaky surface casing check valve is suspected, then a recommended practice is to always test both for a pressure leak. The procedure to test a check valve is to apply pressure on the downstream side of the valve and determine if the pressure leaks back into the upstream side of the valve. Prudent operators design their surface piping so that this test is simple to perform. Such designs that allow a quick pressure test of the surface check valve will prevent costly workovers due to a misdiagnosed downhole problem. HIT and a leaky surface casing check valve have many of the same symptoms, but with a HIT the tubing will not pass a pressure test of the tubing.

Pressure Sampling

A measured surface dynamometer card (plot of measured polished rod load at the various positions throughout a complete stroke) is commonly used to analyze the operation of a sucker rod pumping system. Portable computers and digital instrumentation software applications are available to acquire current and power data with dynamometer records to provide the necessary information to perform a very complete analysis of the beam pumping system[1]. New generation software and hardware take advantage of the tremendous increase in laptop processing speed, memory size and screen resolution to generate in real time a quantitative visualization of the surface dynamometer card with tubing pressure, downhole rod pump operation, plunger motion, valve action and fluid flow[2]. The data is transmitted to the Wireless Base Station connected to the USB port of the user's laptop computer. Generally the pressure measurement is performed in conjunction with acquisition of dynamometer data. The processing speed of the laptop computers allows storing and manipulating massive amounts of data. Continuous data recording allows the operator to identify the frequency of tubing pressure changes which may indicate problems in the operation of the beam pumping system. High speed and high resolution pressure and dynamometer data are used identify how the pump system is performing and trouble shoot problems.

How to Perform a Tubing Integrity Pressure Test

The remainder of this paper discusses performing and analyzing tubing integrity pressure tests. The pressure data is primarily acquired during the wireless acquisition of dynamometer data. The tubing pressure is simultaneously acquired with a wireless pressure sensor connected to the tubing at the pumping-tee or at the flowline fluid sampling valve. The tubing integrity test should be run at the end of running the conventional valve test. This test is normally done by using the sucker rod pump to increase (pump up) the tubing pressure with each pump stroke discharging oil, water and gas into the tubing. Before performing the pressure test determine the number of pump up strokes. When one person is performing the pressure test, then he must close the flow valve at the front of the pumping unit and at the back stop the pumping unit after the desired pressure is reached. The number of pump up stroke must be determined before a pressure test is performed on a well producing primarily liquid. In some wells the tubing pressure builds up to 500 psig in a few strokes. The operator could easily overpressure a stuffing box trying at the back of the pumping unit to decide when to stop for the pressure test.

An additional pressure test should be performed to determine if the casing check valve is holding. A recommended practice as part of all tubing integrity pressure test, the operator should always verify that the casing check valve between flowline and casing is holding pressure. The casing check valve prevents recirculating produced liquids; recirculating out the tubing, through the casing check, back down the casing annulus and back into the pump.

Figure 1 shows the well setup with the wireless pressure transducer attached to the well head. Wireless pressure data is acquired to perform a tubing pressure test first and then the casing check valve is pressure tested. **Figure 2** shows the arrangement of the valves, V1, used to pressure test the tubing and valve, V2, used to pressure test the casing check vale. To perform the casing Check Valve test, the wellhead configuration should have valve (V2) downstream from Tee junction of tubing and casing flow lines. Following is the procedure to perform the tubing integrity pressure test:

1. At the end of running the conventional valve test acquire one minute of tubing pressure data with the unit stopped at the bottom of the stroke to monitor the value of the tubing head pressure when there is no flow and the tubing to flow line valve is open.
2. Close the tubing to flow-line valve, V1, and monitor the tubing pressure for one or more minutes to determine whether: a - pressure stays constant or b-Pressure decreases or c-Pressure increases. This determines the composition of the fluid in the tubing, (If a or b are true then fluid is primarily liquid. If c is true then tubing has significant gas (correspondingly the pump card should show partial liquid fillage).
3. Run the unit for 2 complete strokes, stop unit and set brake. Monitor the corresponding change in pressure. Determine the increase in pressure psi per stroke.
4. Estimate number of strokes (N) required to reach the desired tubing Integrity Test Pressure. Divide that number of strokes by two. Run the unit for N/2 strokes then stop and set the brake.
5. Monitor pressure for one minute.(If necessary make adjustments to pressure increase per unit stroke)
6. Turn on unit for remaining number of strokes. Monitor the recorded pressure on the screen, allowing the pump to increase the tubing pressure to the desired pressure, and then stop the pumping unit.
7. Tubing pressure increased above flow line pressure by shutting valve V1 until desired test pressure reached. The tubing is usually pressured up to 500 psig.
8. Normally when a hole is present, then the tubing pressure will very quickly leak off (30 seconds to a minute)
9. Watch the pressure for a 10 minute time period. A tubing collar leak can take as much as 10 minutes to leak off 500 psig of pressure.
10. No significant tubing leak is likely, if the tubing pressure change is small. After stopping, the tubing pressure may:
    a. Increase as the gas discharged from the pump segregates in the tubing and rises to the surface.
    b. Decrease slightly as the temperature of hot produced tubing liquid equalizes to the geothermal temperature gradient of the wellbore.
    c. Remain fairly constant
11. If tubing is not leaking or leak is not very significant, then at the end of the tubing pressure test verify the casing check valve is holding.
12. Check the Casing Check valve by closing the valve to the flow line (V2) and opening valve V1as illustrated in Figure 3.
13. Monitor pressure:
    a. Pressure will drop a little as pressure between V1 and V2 equalize, but if the pressure holds then the casing check valve is OK

b. If pressure drops significantly, then the Casing Check valve has a problem

Example Tubing Integrity Pressure Test Data

Figure 4 shows pressure data acquired versus elapsed time during a tubing pressure test. This pressure versus time data is used to illustrate some of the features that can be identified and discuss some of the key events that can occur during a pressure test. Six key events are identified and labeled to correspond to the sequence of events occurring during this particular test. Please note that this is one of many different possible ways to run the test.

(1) Before this point the pumping unit was operating normally and tubing pressure being recorded shows the normal pump action on the pressure signal. Average pressure is about 65 psi. At point 1 the brake is pulled to stop the pumping unit.

(1) to (2) with the surface valve open the monitored pressure indicates the flow line pressure. At point (2) the valve from the tubing to the flow line is closed sealing the tubing string at the surface. Presumably the standing valve, SV, seals at the bottom of the tubing, and traveling valve, TV, also provides a seal except for slippage normally occurring through the plunger/barrel clearance.

(2) to (3) the pressure shows an increasing trend from 65 psi to 95 psi. The increasing tubing pressure indicates that the high pressure gas discharged every pump stroke into the tubing is percolating through the liquid in the tubing and rising to the surface. While the pumping unit is stopped, liquid and gas in the tubing segregate with the light gas floating toward the surface. The surface pressure increases as more and more of the high pressure gas near the pump floats to reach the lower pressure gas accumulation at the surface. The rate of pressure increase is a function of the amount of gas present and the rise velocity of the gas bubbles.

(3) to (4) during this time the pump is stroked, about 7 times in three steps, while monitoring the tubing pressure. The first 2 strokes then stopped to monitor pressure for about 30 seconds. Then 2 more strokes and stopped for about one minute. Then more strokes until pressure increased to 130 psi then stopped at (4)

(4) to (5) final monitoring of pressure to see whether the surface pressure stays constant, decreases, or increases. This test showed slight increase over almost one minute of elapsed time.

(5) to (6) Valve to flow line is opened and the pressure monitored at the surface quickly decreases to original flow line pressure.

One reason the pump was stroked in several periods, rather than continuously, was to prevent the surface pressure from building up too high. If/when the tubing is completely filled with incompressible liquid, then the surface pressure can quickly increase to over pressure the stuffing box. Standing at the electrical switch box while using the Wireless Pressure and Dynamometer equipment, the operator may be unable to observe in real time the tubing pressure vs time plot on a laptop screen and decide how many strokes to pump into the closed tubing. Being able to visually monitor the pressure display during the pressure test allow the operator to ensure that the pressure does not exceed the desired maximum tubing head pressure.

Field Dynamometer Example Data

Field dynamometer and tubing integrity pressure test data was acquired on seven different wells. These tubing integrity pressure test will be used identify different problems is these sucker rod pumped wells. Each example well will show a different tubing integrity pressure test idea or concept. The tubing pressure measurement is a valuable tool to confirm that the tubing and surface valves hold pressure during the standard dynamometer testing of the well. When stopping to perform tubing integrity pressure test the plot of changing tubing pressure versus elapsing time can be monitored to determine if the valves and tubing are holding or leaking off.

Example 1

Pressure test was obtained in conjunction with a normal standing and traveling valve test. Dynamometer measurement of polished rod load and position is performed with a series of static measurements to determine the amount of liquid leaking past the valves and through the plunger-barrel clearance. This test is called a “Valve Check” load test. Several polished rod load measurements are taken in sequence first by carefully and gradually stopping the pumping unit on the upstroke (Traveling Valve test, TV) and setting the brake to monitor the load for a period of time. After resuming pumping and completing a few pump strokes, then stopping the unit on the downstroke (Standing Valve test, SV) to monitor the load for a short time. The initial load measured after stopping on the upstroke should be close to weight of the rods submerged in the tubing's fluid (Wrf) plus the fluid load (Fo) on the plunger. When stopping on the downstroke, the initial load value should be close to the Weight of the rods in fluid (Wrf). In both tests a change of the load while the unit is stopped is an indication of fluid leakage. The upper right hand of Figure 5 shows a typical record of the valve test for a case where there is no leakage. The vertical axis is polished rod load, units of kLb, and the horizontal axis is elapsed time, in units minutes and seconds (mm:ss).

The number of pump up stroke should be determined before a pressure test is performed on a well producing primarily liquid. If one person is performing the pressure test, then he must close the flow valve and stop the pumping unit after the desired pressure is reached. At the back of the pumping unit without seeing the display of the laptop the operator will not know when the desired pressure is reached.. Notice **Fig. 6** in the lower left corner of the plot the tubing pressure built up to 500 psi in just 3 strokes (166 psi/stroke). If the number of strokes required to reach 500 psi were not known, then the operator could easily overpressure the stuffing box while he is at the back of the pumping unit deciding when to stop for the pressure test. At the beginning of stroke 9 the flow line valve was closed and the tubing pressure reached 500 psi when the brake was set during stroke 12. The tubing pressure remained constant during the standing valve test time of 2:00 to 03:18. The traveling valve check load test is performed by bring the pumping unit to a stop about ¼ from the top of the stroke, the tubing pressure increased to 540 psi and remained fairly constant until pumping resumed at 04:50. The tested production rate from this well is 128 BPD, which matches pump displacement determined using the pump card. The tubing pressure remained fairly constant during the time period when the unit was stopped. The tubing integrity pressure test, valve test, and dynamometer card analysis confirmed that the tubing and valves in this well are not leaking.

Example 2

The pressure test for Example 2 well is shown in **Fig. 7**. For stroke 50 the average tubing pressure is 25 Psig. The flow line valve is closed at the beginning of stroke 51 and the tubing pressure increased to 580 Psig when the break was pulled at the end of stroke 53 to stop the pumping unit. The well may have a slow tubing collar leak since over an elapsed time of 10 minutes the tubing pressure leaking off from 590 to 530 Psig, but this comparatively small pressure change may be caused by the tubing liquids equalizing with the temperature of the earth.

A pump appears to be functioning properly when the pump card shape shows the pump to be filled with liquid, since no gas is inside the pump and the pump's traveling and standing valves are not leaking. To calculate the theoretical or expected fluid load, Fo from the Fluid Level acting across the plunger, then the pump intake pressure, Pi, pump discharge pressure, Pd, and plunger area, A, are used (Fo=(Pd-Pi)A). If the downhole pump card height is much less than the expected Fo from the Fluid Level, then there may a tubing or pump leak, a worn out pump, leaky valves or a high tubing-casing annulus fluid level the pump. **Fig. 8** shows an abnormally low pump card fluid load of 1355 lbs. The fluid level is 6511 feet from the surface and the pump card loads should be near the 3730 lbs fluid load calculated from the differential pressure acting across the 1.25 inch diameter plunger. The hole in the tubing is 4005 feet from the surface and the pump is lifting liquid up the tubing approximately 2500 feet to discharge out the tubing hole into the casing and circulating liquid back down the casing annulus to keep the pump filled with liquid. The hole in the tubing is 4005 feet from the surface and pump card load on the upstroke is too low because the pump only lifts the liquid approximately 35% of the distance to the surface to be discharge out the hole at a depth of 4005.

The low pump card height for Example 2 well, **Fig. 9**, often would cause the operator to suspect a hole in the tubing (as discussed in the previous paragraph). The tubing pressure held fairly constant over a 10 minute time interval, there does not appear to be a hole in the tubing. The tubing quickly pressured up from 25 to 530 Psig during the 24 second of elapsed time from stroke 51 to 53, because only liquid was being discharged from the pump into the tubing. Fo from the Fluid Level matches to the height of the downhole pump card, since this well has a very high fluid level. The tubing pressure test indicates that there is no hole in the tubing, but possibly a slow tubing collar leak. The problem identified on this well is the run time is set at 50 % and the well is not being drawn down. A recommendation to increase the run time should result in a significant increase in the production from this well.

Example 3

The pressure test for Example 3 well is shown in **Fig. 11**. Pump strokes are full of liquid, **Fig. 10**. The tubing appears to be filled with incompressible liquid, because the tubing pressure increased from 70 to 400 psig in 3 strokes. The pumping unit was stopped at stroke 36. There does not appear to be a hole in the tubing, because the tubing pressure slowly leaked off from 325 to 270 psig during 11 minutes of elapsed time.

At the point in time where the pumping unit was stopped, then the tubing pressure reach a 420 psig peak pressure. In 1.8 seconds of elapsed time the tubing pressure dropped to 290 psig. In 3.75 seconds of elapsed time after the 420 psig peak pressure occurred, then the tubing pressure increased up to 385 psig. The tubing pressure signal has the shape of an oscillating or repeating wave, with the time between peaks of 3.75 seconds. The peaks appear to be the round trip travel time between the closed flow line valve at the surface and the pump at the bottom of the tubing. This oscillation occurs when pumping is stopped with the surface valve closed and the tubing filled with fairly incompressible liquid. The pump's seating nipple is a depth of 7977 feet and the acoustic velocity of propagation of the wave in the tubing would be (7977 x 2/3.75) 4254 feet/sec, which is a typical acoustic velocity for water. This unique pressure fluctuating signal is created by suddenly stopping the pumping unit with the tubing filled with incompressible liquid. This signal is defined as a water hammer (or, more generally, fluid hammer) where a pressure surge or wave is caused when a fluid (usually a liquid but sometimes also a gas) in motion is forced to stop or change direction suddenly (momentum change). A water hammer commonly occurs when a valve closes suddenly at an end of a pipeline system, and a pressure wave propagates in the pipe. This signal is also called hydraulic shock. When a pressure test is performed on a well and the oscillating water hammer signal is seen at the time of stopping the pumping unit, then the pump is likely filled with liquid and the tubing is filled with fairly incompressible fluid.

Example 4

Figure 12 for example well 4 shows that the surface tubing pressure increases as high pressure gas rises up the tubing after pumping stops. The pump card has 80 % pump fillage and the gas inside the pump is discharged into the tubing at 3801 psig pressure. At stroke 79 the flow line valve is closed and the tubing pressure of 190 psig gradually increases at 8.6 psi per stroke. After 36 strokes the tubing pressure increased to 500 psig when the pumping unit was stopped at stroke 115. The surface flow line valve remained closed for 4.5 minutes with the pumping unit stopped and the tubing pressure increased from 500 to 560 psig. In this well the tubing pressure did not leak off, indicating there is no hole in the tubing.

The pump card shape displays gas in the pump and the gas in the pump is compressed and discharged from the pump. This compressed high pressure gas is discharged into the tubing at a 3801 psig pressure. Since there was gas inside the pump a pretest was not required because the tubing pressure slowly increased at 8.6 psi per stroke. The gas in the tubing tends to slip through the liquid in the tubing upward toward the surface. Once the pumping unit is stopped to determine if the tubing pressure will hold, then the higher pressure gas at the near the pump discharge will continue to float through the liquid and accumulate near the top of the tubing string. As the higher pressure gas mixes with the lower pressure gas near the surface, then the tubing pressure at 500 psig increased to 560 psig until the point in time when the surface valve was opened at 21:00.

Example 5

Figure 13 for example well 5 shows a pump filled with liquid. Fo from the fluid level and Fo Max are approximately equal to the pump card height. There is no production to surface from the well and even though the pump card shows a pump displacement of 268 BPD. Figure 14 shows that the tubing pressure near 0 and not changing with the surface flow line is closed. The tubing is filled with liquid based on the pump card height. The fluid level is close to the pump intake based on Fo from the fluid level. The tubing flow line valve was shut-in at stroke 10; the tubing pressure does not increase during 93 pump strokes filled with liquid. Even though 268 BPD of liquid is being discharged from the pump, none of the liquid can exit the tubing since the flow line valve is closed. There is a hole in the tubing since the closed flow line valve isolates the casing check valve from the tubing. Since the pump card loads are high, it is likely that the hole in the tubing is near the surface.

Example 6

Figure 15 for example well 6 shows a leaky standing valve diagnostic pump card shape. The tubing pressure is zero, but increases to 80 psig at the bottom of the stroke, when the flow line valve to the tubing is open. The tubing pressure during each stroke leaks off to zero pressure at the top of the stroke when the flow line to the tubing is closed. The flow line to the tubing is closed for strokes 130 to 133 and the tubing pressure increases to 480 psi at the bottom of stroke 133. This well has a very leaky standing valve and likely worn plunger and barrel, where liquid enters the tubing on the upstroke but all of the pressure leaks back out the SV to 0 pressure during the top 1/2 of the stroke.

Example 7

Figure 16 for example well 7 shows a full pump with a 145 BPD discharged from pump with the tubing valve closed with no pressure build up. On every stroke the tubing pressure suddenly drops from 45 psi to 40 psi due at 2.5

seconds of an 11 second stroke. A sudden drop in pressure during the upstroke can be due to a hole is a bottom hold down pump.

Conclusion

This paper describes the use of a Wireless High Speed Pressure Transducer measuring system that can be used to monitor the operation and performance of beam pumping wells. Dynamometer, power analysis and tubing pressure testing is routinely performed on beam pumped wells throughout the world. While pumping or while stopped the wireless pressure data can be acquired simultaneous with dynamometer load and position, motor power, current, and voltage.

A tubing pressure test can be used to identify a hole-in-tubing or a leaking valve using the procedure outlined earlier in a section in this article. When the tubing pressure rapidly leaks off when the unit is stopped, then often there is a likely leak in the tubing. If a hole is present, then often the tubing pressure will quickly leak off or NOT build-up pressure.

A full pump card shape means the tubing is likely full of incompressible liquid, then the operator should expect the tubing pressure can quickly increase with each stroke after the surface valve is closed for a tubing pressure test. To prevent blowing-out-the-stuffing-box or over-pressuring the tubing, then a pretest should be performed to count the number of strokes required to increase the tubing pressure to the desired level. Once the number of strokes is determined; then release the surface pressure, reclose the surface valve, start counting strokes, and stop the pumping unit at the exact point in time where the counted number of strokes has occurred. In some cases one (1) additional pump stroke displacing water into the tubing can result in the stuffing box leaking due to over-pressure.

If the pump card shape displays gas in the pump, then compressible fluid at the pump discharge is entering the tubing. A pretest is not required because the tubing pressure will slowly increase, even if there is no leak. The gas in the tubing tends to slip through the liquid in the tubing, Once the pumping unit is stopped to pressure test the tubing, then the higher pressure gas at the near the pump discharge will continue to float through the liquid and accumulate at the top of the tubing string. As the higher pressure gas near the pump mixes with the lower pressure gas near the surface, then the tubing pressure will slowly increase and the tubing surface pressure will continue to increase after pumping stops.

When the measured liquid production rate from a well suddenly decreases or stops, then pressure testing the tubing for a hole important trouble shooting step. Also important is to "ANALYSIS BEFORE ACTION" the well and not pull the tubing string without a hole being in the tubing. The pressure test should confirm that the loss in production is not due to the produced liquids leaking back down past the surface casing check valve or the tubing back pressure valve is not holding pressure.

Wireless tubing pressure measurement is a valuable tool for the operator to confirm that the tubing and surface valves hold pressure during the standard dynamometer testing of the well. When stopping to perform static traveling and standing valve tests the plot of changing tubing pressure versus elapsing time can be monitored to determine if the valves and tubing are holding pressure or leaking pressure off. High speed pressure data acquired in conjunction with a load and position from a dynamometer increases the knowledge of the operator and provides an enhanced troubleshooting capability.

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Nomenclature:

A = plunger area, square inches

Pd = Pump Discharge pressure, psi

Pi = Pump Intake pressure, psi

Figure 1 – Specific Well Setup to Pressure Test Tubing and Then Pressure Test Casing Check Valve

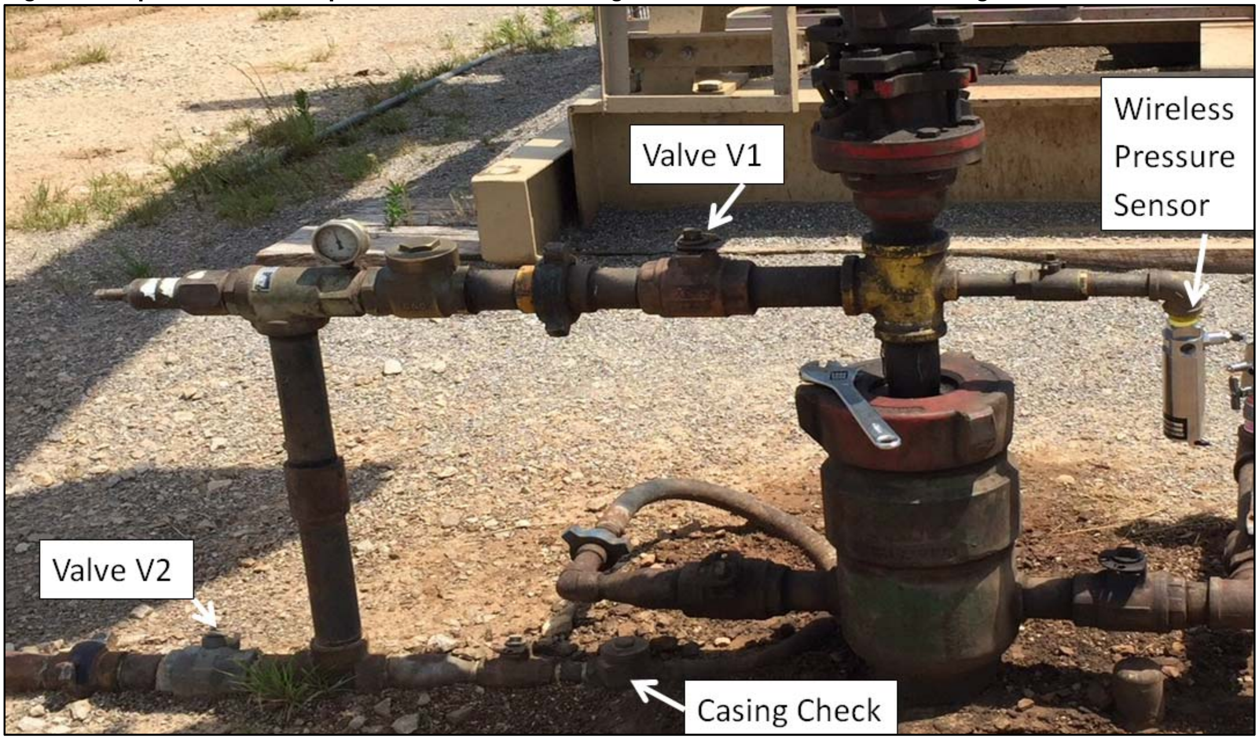

Figure 2 – Check If Valve Between Flowline and Casing is Holding to Prevent Liquid Recirculating Out the Tubing Back Down the Casing

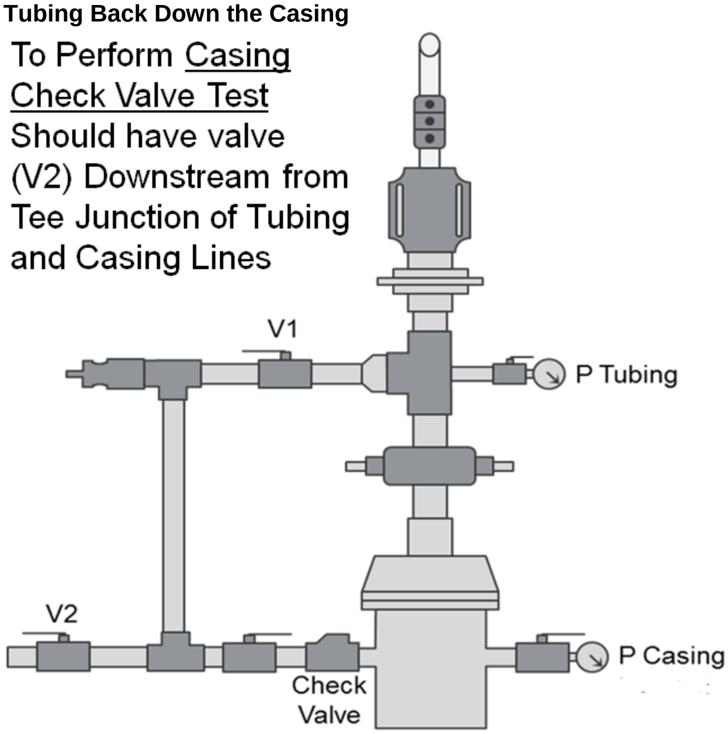

Figure 3 – Verified Casing Check Valve is OK and Holding Pressure

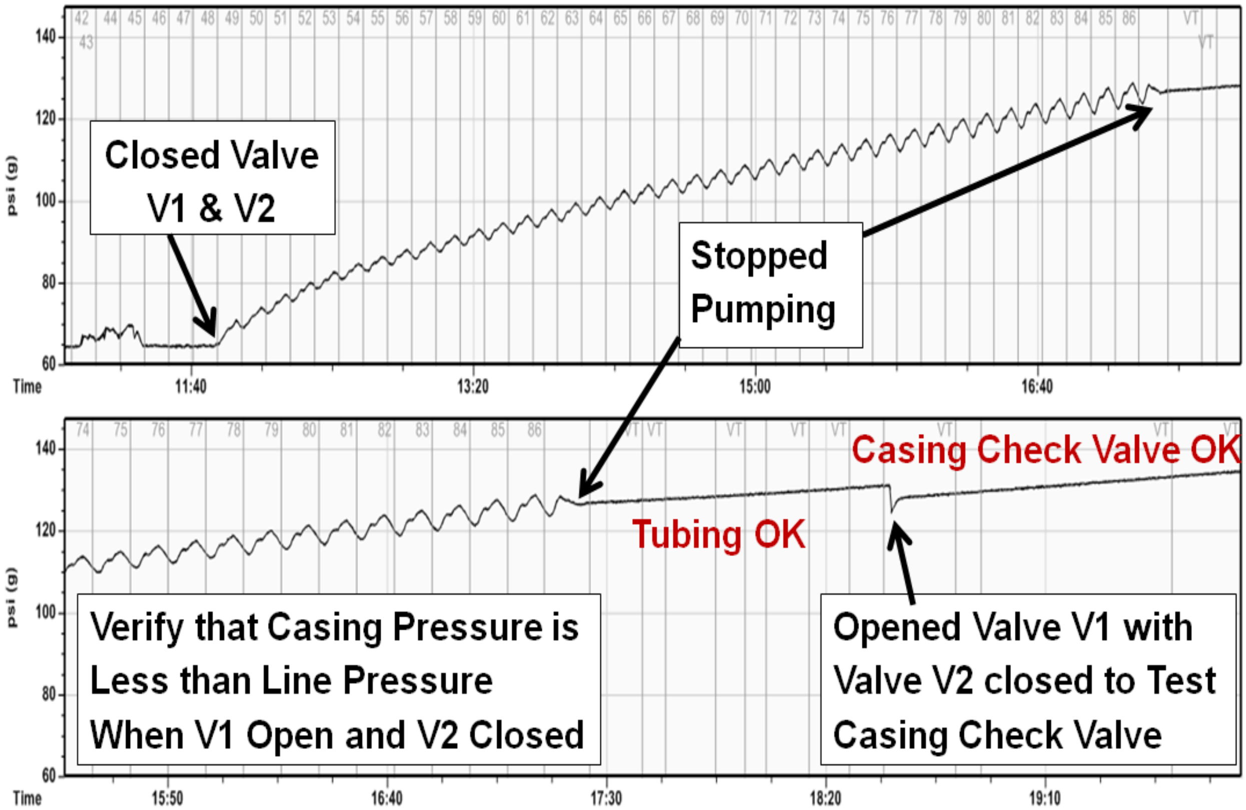

Figure 4 – Pressure Data Acquired versus Elapsed Time During an Example Tubing Pressure Test

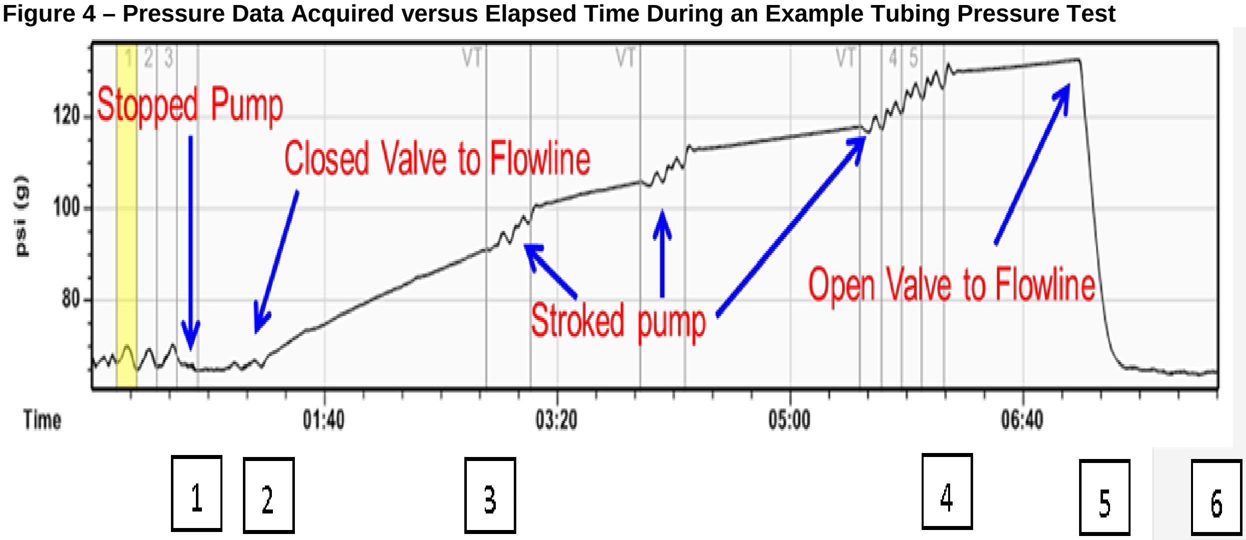

Figure 5 – Example 1: – Dynamometer Data Liquid Filled Pump Displacement Matches Production Rate

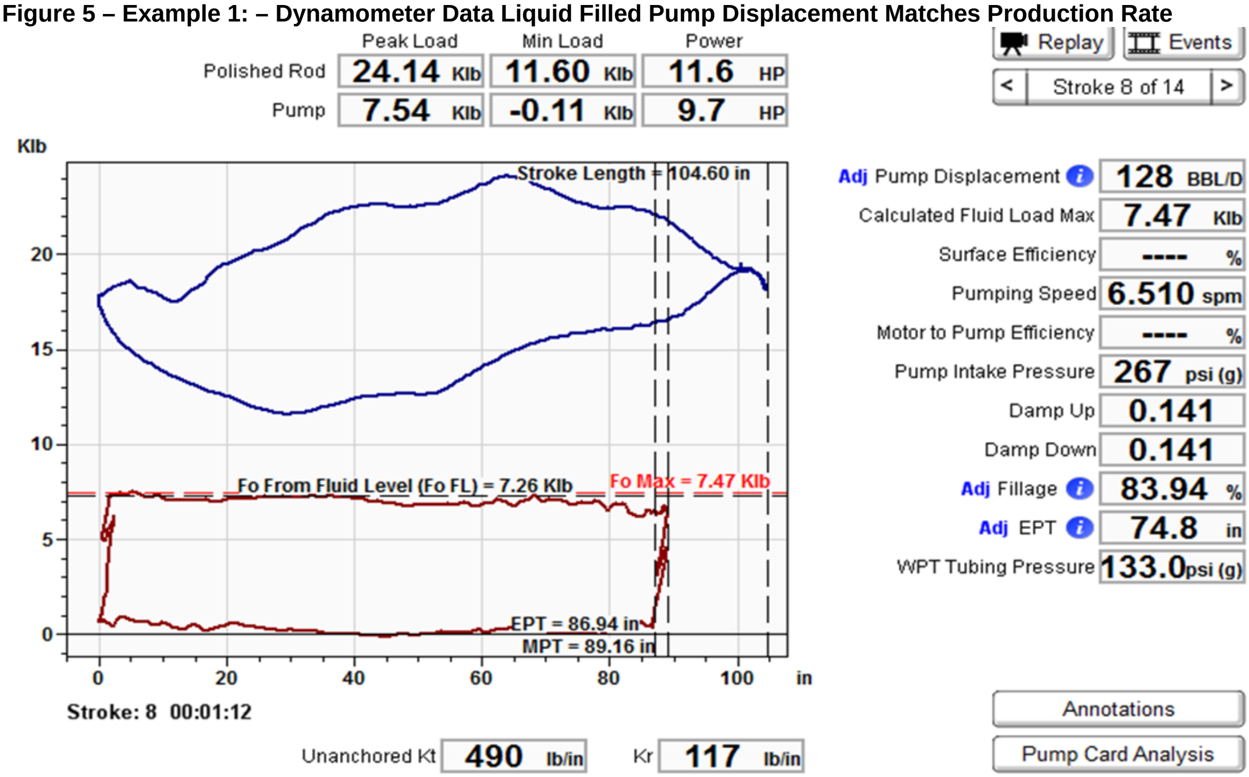

Figure 6 – Example 1: Pressure Test as Part of Standing and Traveling Valve Test

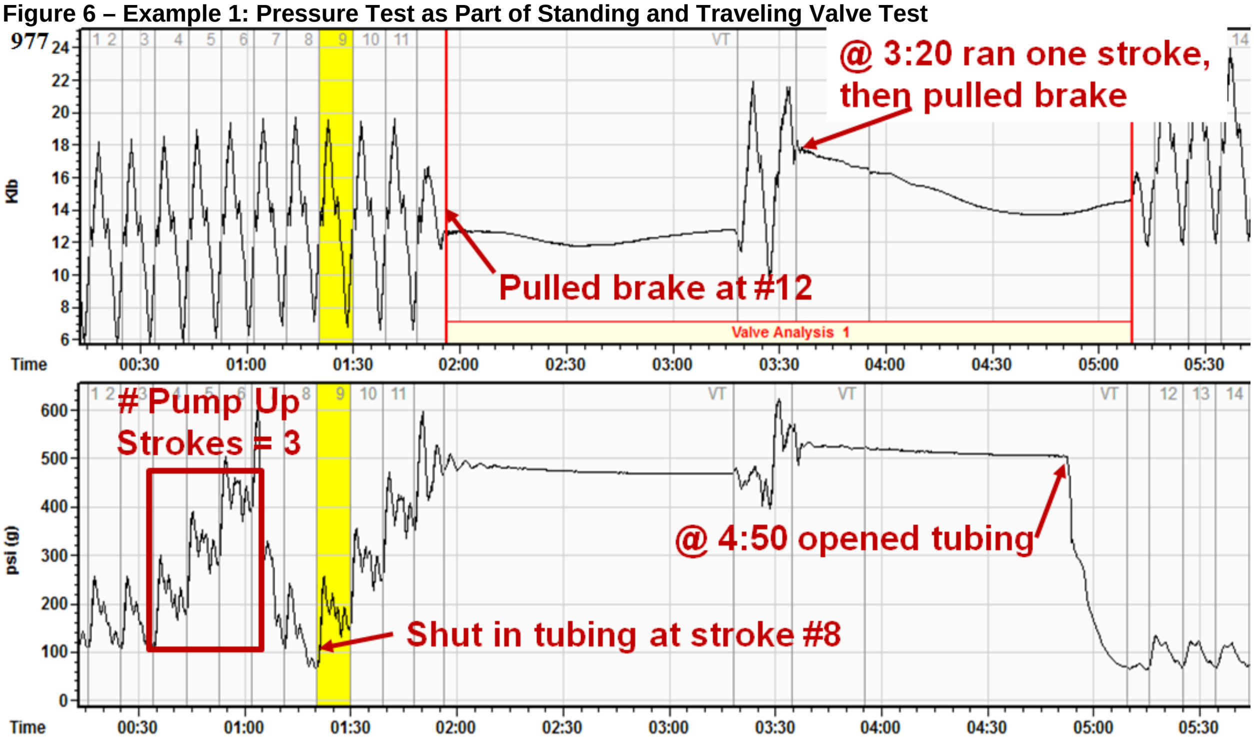

Figure 7 – Example 2: Tubing Pressure Leaks Off from 590 to 530 Psig in Elapsed Time of 10 Minutes

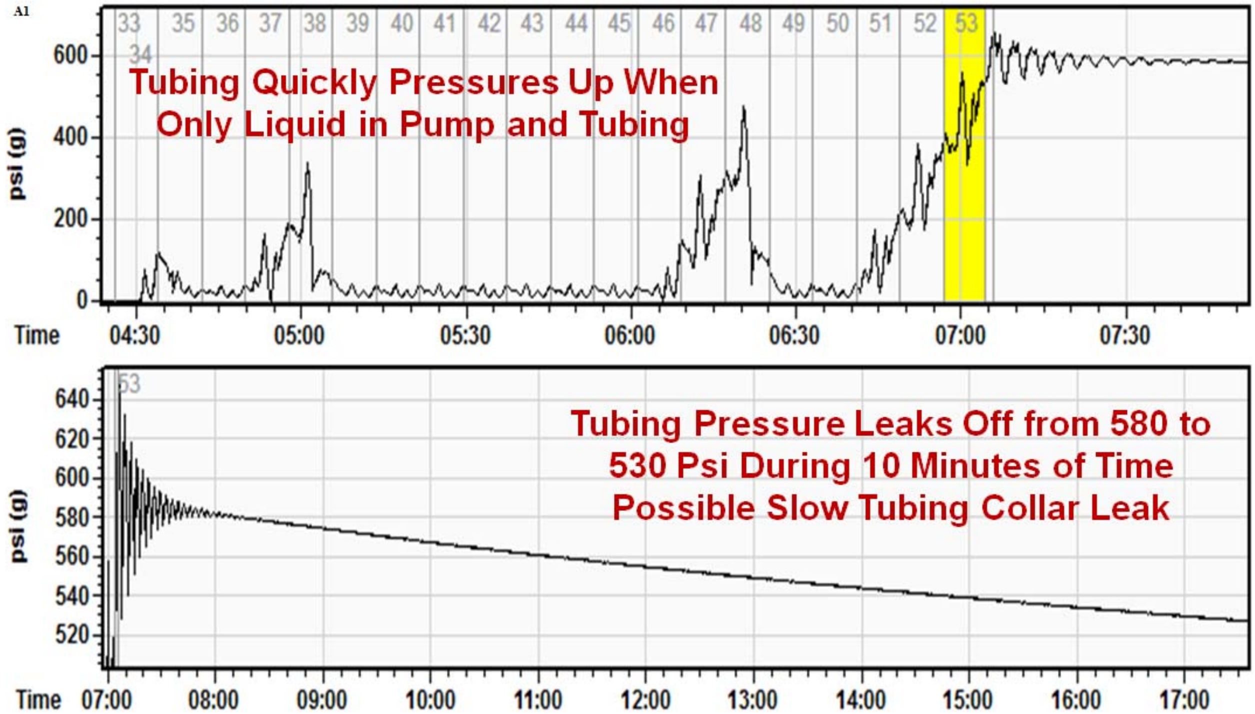

Figure 8 – Example 2: Well A1 Showing Pump Card for Hole in Tubing

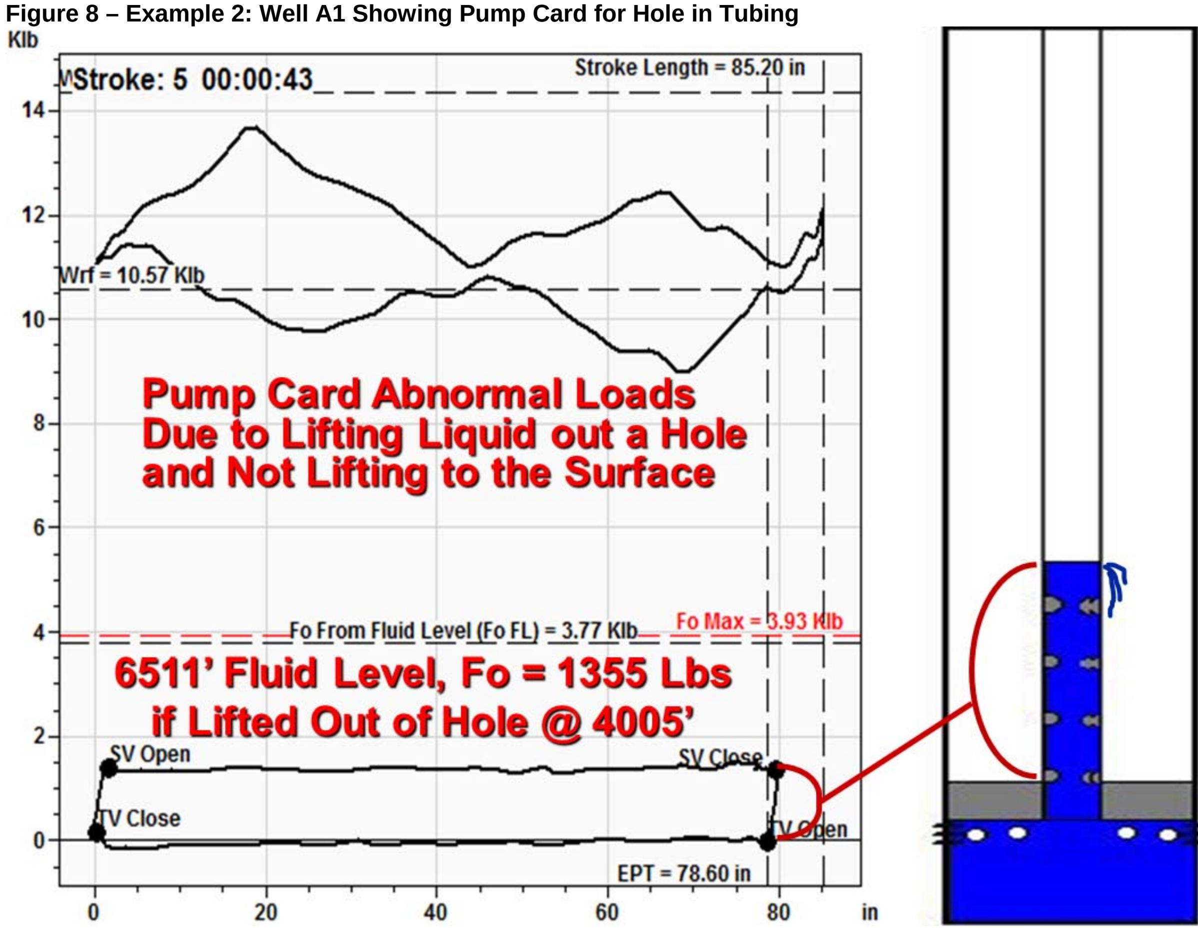

Figure 9 – Example 2: Run Time is 50% Resulting in High Fluid Level and Pump Full of Liquid

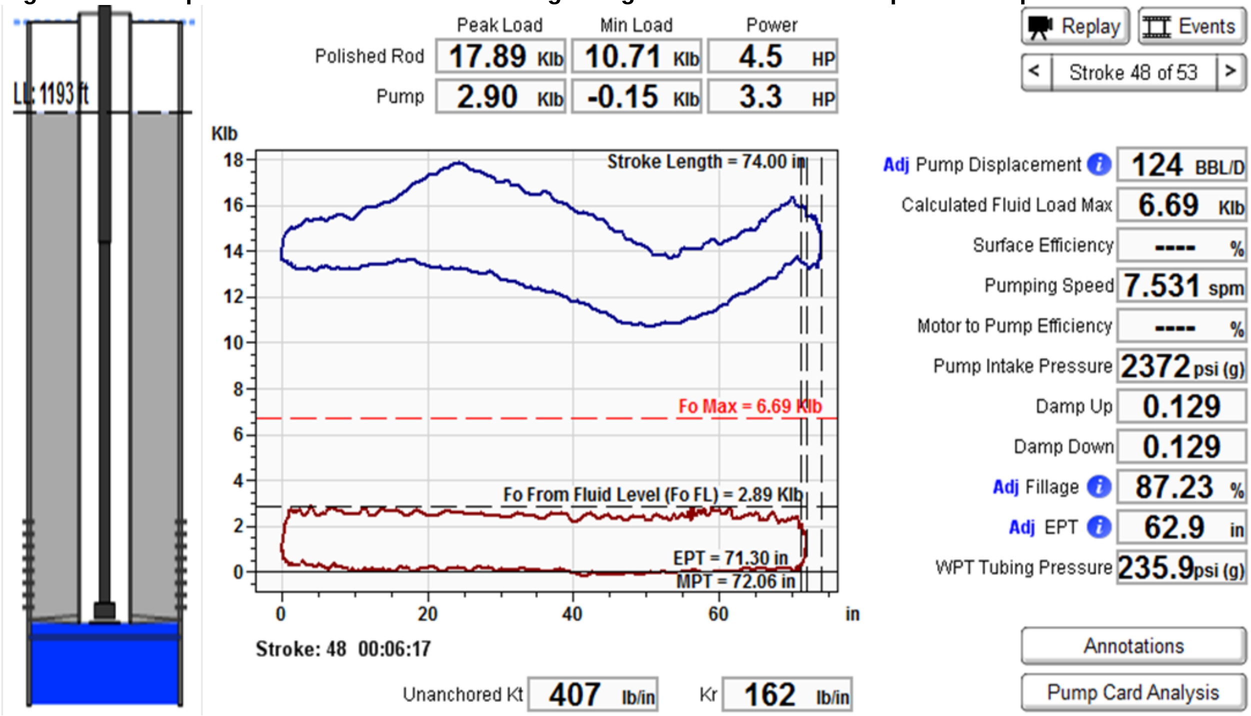

Figure 10 – Example 3: Well 7 Strokes 25-32 ~ Pump is Full of Liquid

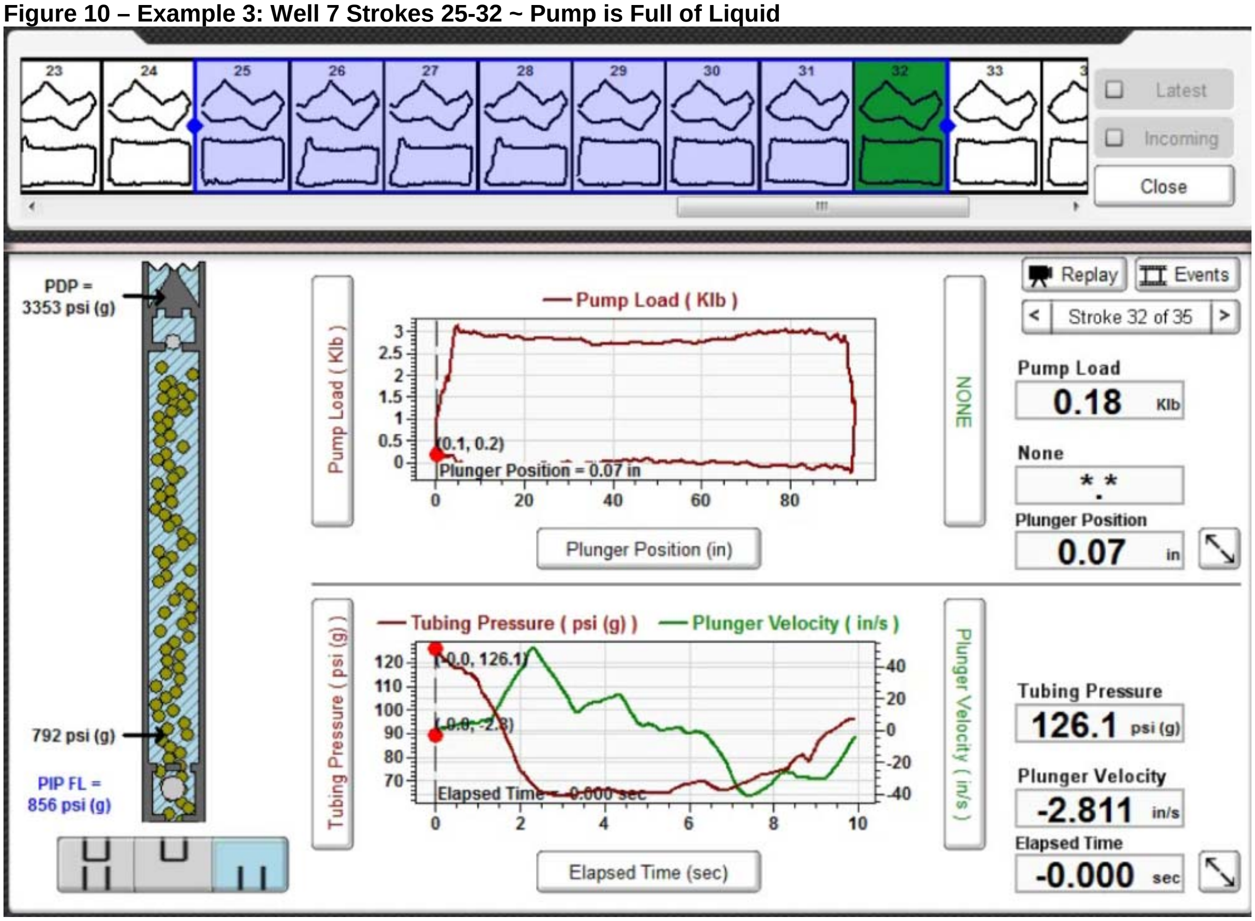

Figure 11 – Example 3: Tubing Pressures Up Quickly and Slow Leak off May Indicate Minor Tubing Collar Leak

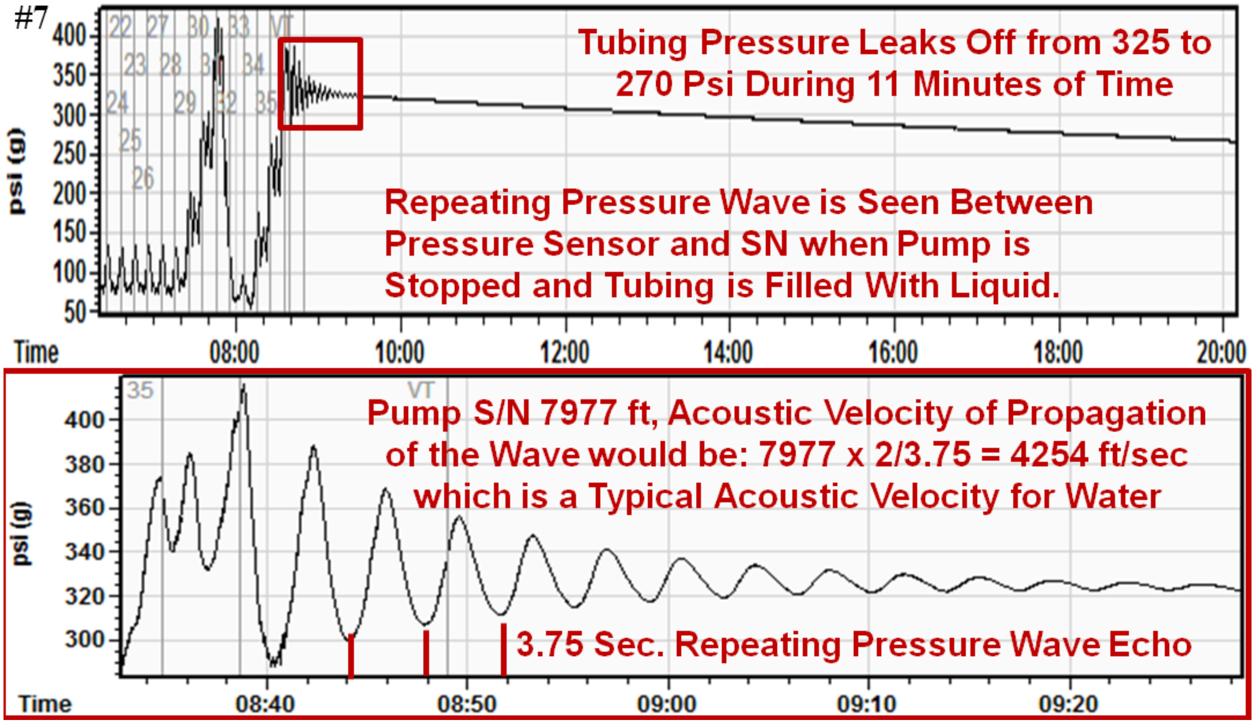

Figure 12 – Example 4: Surface Pressure Increases as High Pressure Gas Rises up Tubing After Pumping Stops

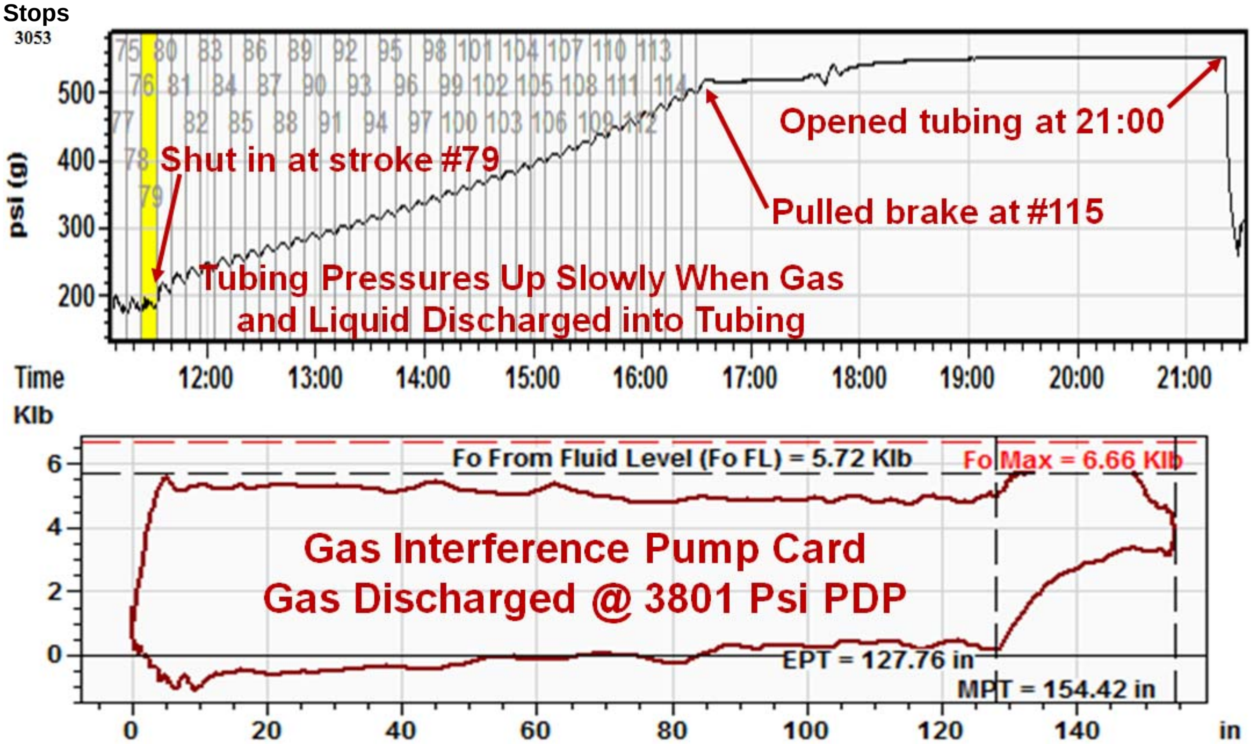

Figure 13 – Example 5: 269 BPD Adjusted Pump Displacement Shut-in @ Stroke #10 - NO Pressure Increase NO Production

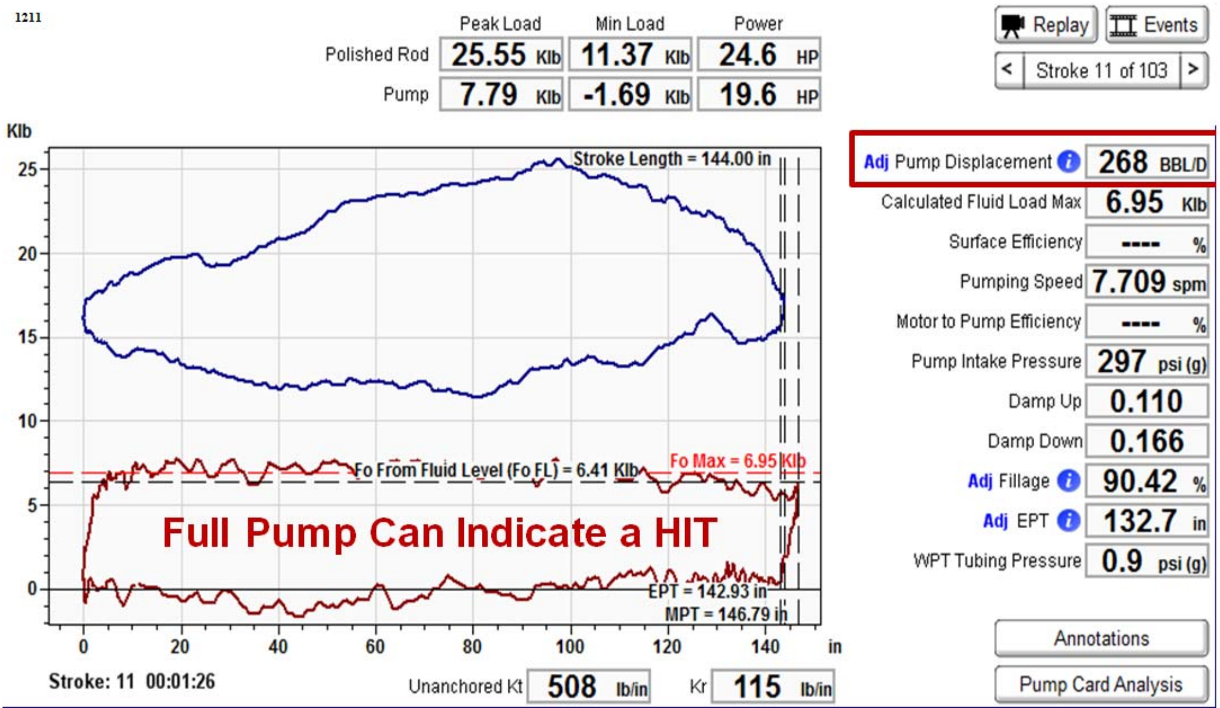

Figure 14 – Example 5: Likely Hole in Tubing Near Surface, Lifting Liquid to Surface Since Pump Card Height near FoMax

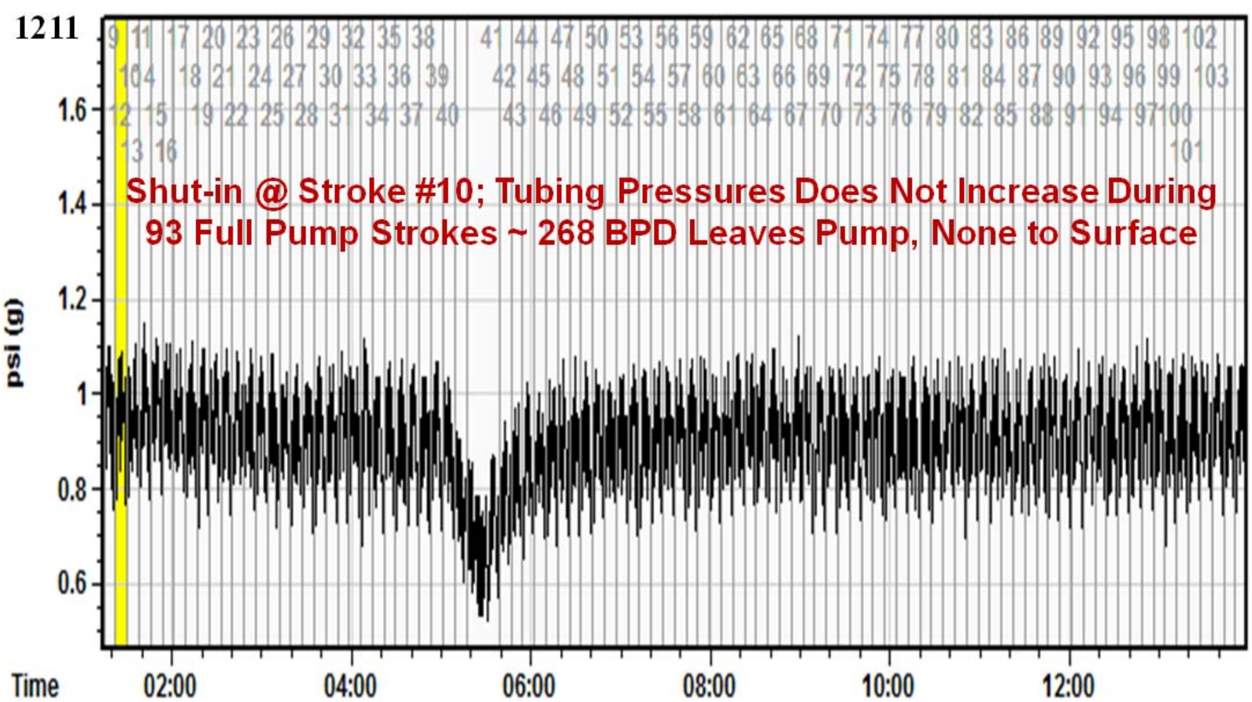

Figure 15 – Example 6: Leaky Standing Valve with Very High Fluid Level, Pressure Increases at Bottom of Down Stroke

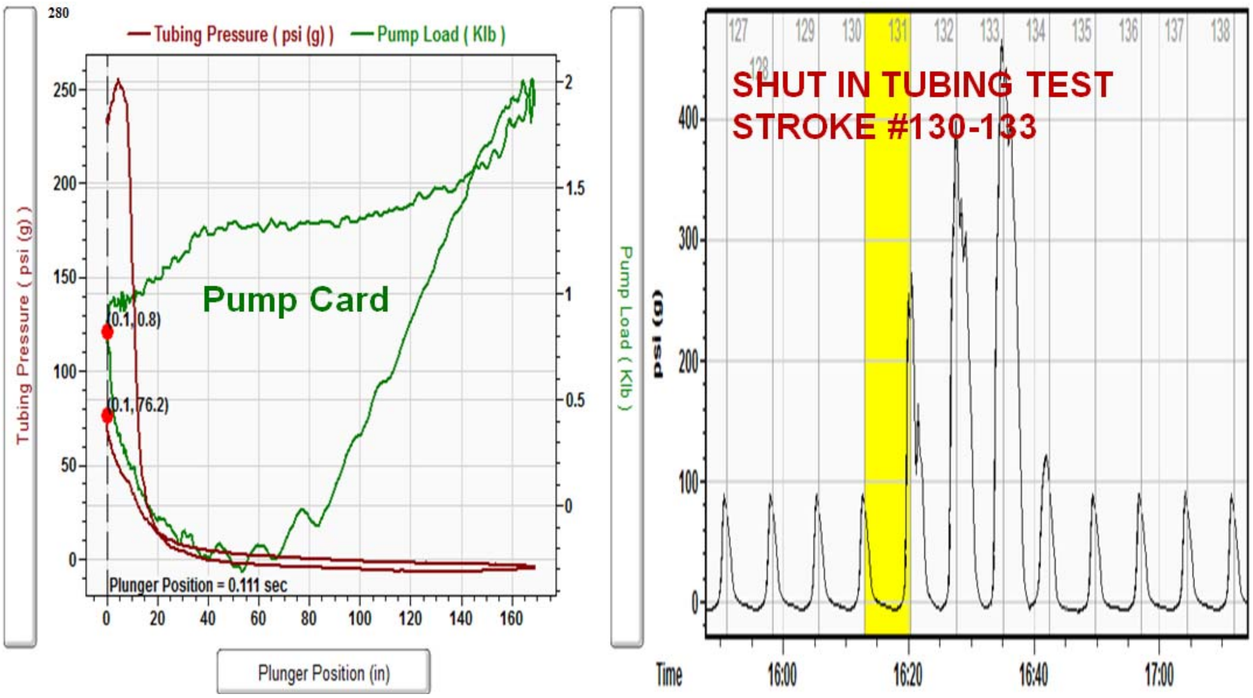

Figure 16 – Example 7: 145 BPD Discharged From Pump Tubing Valve Closed with NO Pressure Buildup