# PREVENTING TUBING LEAKS IN THE FIELD
# "A REALITY CHECK"

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ABSTRACT

Tubing leaks due to rod wear and corrosion are common in the oil field and can add significantly to the operating cost of any well. The preferred field applicable approaches to finding production tubing weak spots and leaks vary with different companies and range from pouring paint from a bucket, hydrostatic testing, and electronic inspection of the tubing as it is tripped.

We have taken field data from numerous jobs and explored how each of these testing methods can be improved or enhanced to increase information reliability and to reduce the frequency and cost of well failures.

**Caveat: It is not the purpose of this paper to review or judge the attributes of the various techniques and apparatus used in electronic tubing inspection services as the equipment varies in how it works and how it is built. This paper addresses how the on-lease technology is applied over the well and how the results can change based on field applications and interpretations.**

## INTRODUCTION

Sir Isaac Newton lived in the 1,600's and developed three laws of motion. Had he lived in our generation; had a laptop; worked in the oilfield; and contracted service companies, he would have, no doubt, stumbled upon many more laws and truisms that govern nature, motion, and people. Newton's additional laws might read as follows:

- Number 4: All laws of science will be thrown out the window, totally discounted, or significantly altered when applied to the oilfield.
- Number 5: Things are never as they seem.
- Number 6: Rarely do things happen as planned.
- Number 7: When the response to a "Why" question is "I have always done it that way," you have found good patentable art and a process or procedure that can be improved upon.

Tubing leaks are mostly due to rod wear, corrosion, or both, and represent a significant cost to operating a well. In fact, some numbers suggest that upwards of 30% of the operating cost of a well is attributed to the problem of tubing leaks. After a well goes down, two general operational-type "systems" kick into gear. First, the field moves in a service rig, finds, and replaces the bad tubing. Second, the office wants to know why the leak occurred and how to prevent future failures. The field is driven by getting the well back on with minimum expense and time; and the office is driven by the quest for information including: What was the root problem, rod wear, wrong chemicals, chemicals not getting on the spot, age of the tubulars, technique, or other possible causes that need to be evaluated. The office needs data to sort out all the variables and reduce the probability of the same thing happening in the future and to ensure that decisions and conclusions are valid, it is critical the data be accurate. This paper addresses the challenge of trying to find the balance between the needs of the field and the needs of the office.

## THE BASIC SCIENCE OF PIPE INSPECTION

Magnetic fields, both natural and induced, are well organized and behave in a predictable way. The lines joining the poles of magnets are called flux lines and are illustrated in detail in Figure 1. For the most part, flux lines follow three basic rules:

- They are oriented from North to South and are distributed symmetrically.
- They never cross.
- They will follow the path of least resistance.

By applying magnetic field knowledge to a joint of pipe being inspected, we can predict what the condition of the pipe may be. The magnetic permeability of pipe is about a hundred times greater than the magnetic permeability of air and therefore, if a joint of pipe is exposed to a magnetic field, by rule, the flux lines must follow the path of least resistance and therefore be attracted to and flow through the pipe. The flux lines would be orderly and might look like Figure 2.

If, however, there is a flaw, or loss of steel within the pipe, the magnetic flux lines would try to detour around the flaw causing a magnetic disturbance or discontinuity as illustrated in Figure 3.

With this basic knowledge, the above illustrations can be summarized as: If we can measure the locally induced magnetic field, or the changes in magnetic fields of a joint of pipe, we can determine the condition of that piece of pipe.

## ELECTRO-MAGNIFICATION AND INDUCTANCE

Electricity passing through a coil of wire produces a magnetic field around the coil. Similarly, moving a magnet or a magnetic field within a coil of wire produces electricity. This process is called inductance and we see applications of this science daily without even knowing it. If an inductive device is placed in a metal container and hung on a light pole, it is called a transformer. If the inductive device is run downhole in an oil well, the perforators call it a collar locator or, a casing inspection-logging tool. If this inductance device is installed over a wellhead and a service rig pulls tubing through it, it is called an "Electronic Tubing Scanner." All these devices work on the principal of "Inductance", which is defined as "Electricity produces magnetism and mutually, magnetism produces electricity."

In the case of an electronic casing or tubing inspection, a joint of pipe is pulled through a coil of wire that has electricity passing through it. Because of inductance, the section of pipe being inspected becomes a temporary magnet. All scanning equipment measures and records on a chart the response and variation to this induced magnetism.

Magnetism in a pipe, either natural or induced, can be measured in many ways, but the two most common methods used in our oil -field are illustrated in Figures 4 and 5.

Figure 4 illustrates one of the methods of measuring the induced magnetism of a joint of pipe. On the left is an electrically energized coil wrapped around a pipe. Energy from this coil induces a temporary magnetic field into the pipe. Also wrapped around the pipe is the receiving coil (on the right hand side). If the current is held steady in the energizing coil, the amount of current or voltage measured in the receiving coil is proportional to the changes in the amount of magnetic permeability between two coils. The most magnetically permeable environment, of course, is the pipe being pulled through the coils, so any changes in the pipe will be reflected in the current measured in the receiving coil.

Another approach to measuring magnetism is the Hall Effect sensor. Many years after Newton's laws of nature were formulated American physicist Edwin Hall made a discovery. He found that when a conductor, or semiconductor, with current flowing in one direction was introduced in a perpendicular position to a magnetic field, a voltage could be measured at right angles to the current path. This discovery is illustrated below In Figure 5 and is called the Hall Effect sensor.

The Hall Effect sensor as shown above and the electro-magnification and inductance pick-up coils discussed in Figure 4 serve the same purpose as they both detect the induced magnetism. By placing an array of Hall Effect sensors or a multitude of coils at strategically located places on the pipe, the total induced magnetism, which is a function of wall thickness, can be determined and the change in the magnetic field immediately adjacent to the individual coil or sensor can detect pitting or holes.

In the scanning industry, the measuring and recording of the respective responses to the total induced magnetism is done on a time-based chart as shown in Figure 6.

## RADIATION

There is an alternative way to measure wall thickness of a joint of pipe and this system uses a Cesium 137 radioactive source that emits high-energy gamma rays. This process is common in the oilfield as the openhole logging companies adapt the "scattering of gamma rays" principal and call it a Density Log. The cementing companies measure the weight of the slurry going down hole and they call their device a densitometer. The Cesium 137 source is a fission by-product of plutonium and uranium and in the decaying process will emit very high-energy gamma rays. These rays can travel at a high rate of speed and behave like a particle enabling them to penetrate deeply into both metal and the human body. Gamma rays, if possible, will avoid collisions and if in the situation of approaching a molecule of metal, they will bend and try to go around the molecule to avoid it. In this process, each bending motion depletes speed and energy and eventually, the gamma rays lose sufficient velocity and will be absorbed by the metal. The more dense the material, the more deflections occur. The scanning industry approach is to bombard a joint of pipe with gamma rays and measure how many make it across the joint of pipe before getting absorbed or die. The sensor count rate is converted to and displayed as wall thickness units rather than count rate.

By rotating the source and detector around the pipe, the scanning tool scans in a 360- degree pattern. It can be seen from the right hand side of Figure 7, the speed of the pull and the rotational speed of the detector-source assembly are inter-dependent and the two variables ensure that the entire pipe is inspected.

## ELECTRONIC CIRCUITRY

Intrinsic to all electronic measuring and charting equipment is a phenomenon called "time constant", which is another term for filtering or averaging. In an analog environment, time constant is determined by the resistance-capacitance of the circuit. However, today most of the time constant issues are handled by "geeks" and software. A good example of filtering is in the Microsoft Excel® program, which has an averaging function built into it. Basically, filters are used to join dots, or data points together with lines, averaging the spikes, and making curves look smooth. To increase the smoothness of a curve requires the user to lengthen the time constant or average sensor response over a greater number of samples.

In addition to filtering, almost all electronic measuring equipment has some method to adjust the gain or amplification factor of the sensor's electronics. This can either be a potentiometer knob or software. Simply put, the gain is used to adjust the sensor response to the desired processor's output or to adjust the signal to noise ratio. Another function of the gain control might be to make the equipment respond to meet a standard color calibration. An example might be as follows: A 20 mV signal change at the Hall Effect sensor is needed to represent a wall thickness loss of .05 inches of metal. A standard calibrated joint of pipe with a known wall loss is passed over the sensor and the gain is adjusted until the operator sees the desired response of a wall loss of .05 inches or [.05/.19] or 26% on the chart in the case if 2 3/8" tubing is being inspected.

## SAMPLE RATE

Digital technology arrived many years ago and has developed to the point where modern electronics measure sensor input by taking a reading during a window of time. A simple example of this is the shutter speed of a camera - open, sample, and close. Digital measuring operates in the same way: open the window, read the sample, and close the window. How frequently this window opens up is called the "sample rate." Sample speed, or shutter speed, is governed by the combination of software and hardware and is usually limited by how much the task at hand requires, and how much the user is willing to spend on the equipment. Faster speeds require faster processors and more precise electronics.

## ELECTRONIC SCANNING

Now apply the understanding and appreciation of sensors, coils, filtering, sample rates, and gains to the oilfield art known as "scanning tubing." Figure 8 is a hypothetical joint of pipe being inspected. This joint of pipe has three anomalies within the wall and is passing through the head at two different velocities: V-1 and V-2.

Based on the equipment design and the rig pull speed, the sensor response curves will look much like the curves shown in Figure 9.

Note that at speed V-1 (blue), we get three clearly defined kicks at each of the three pipe deformities. In contrast, at speed V-2 (magenta), which is twice as fast as V-1, we start to lose definition and the deformities start to disappear into the statistical variations of the curves. Additionally, if the pipe had been scanned slightly faster, the deformities would have been completely lost. In electromagnetic measurements, signal levels and strengths depend on how fast lines of force are cut, plus the effects of filtering. To repeat and stress the importance of what was just stated: The response of the equipment is determined by how fast the flux lines are cut.

The graph in Figure 9 visually illustrates two critical points that determine the "look" of the tubing scanned chart:

- There is optimal speed as well as a limit to any scanning equipment
- Varying the speed will impact the charted response as well as the final interpretation of the data.

This moves the discussion to the next question: What is the lower limit, or, is there a lower limit? To investigate this question, we need to look at how the data on a scan is presented. The data is represented as the voltage against time ratio. The equipment charts the sensor response in time as it goes across the screen from right to left. The length of the pipe has no bearing on the response viewed in the screen. The speed that the rig pulls does have an impact on the screen; if the rig pulls rapidly, then the scanning technician is looking at both joints within a stand on one screen. If the rig is pulling slowly, the scanning technician is looking at one joint at a time or maybe only a portion of a joint at a time.

If a pit is pulled too slowly under the sensor, the sensor takes multiple samples per unit of length. Therefore, the rate of wall thickness change per unit of time is small. In the example in Figure 10, that number might be 5% of the wall thickness per unit of time on the chart. If that same joint of pipe is pulled under the sensor at a faster speed, the rate of change might be 50% wall lost per sample rate. At this point, it is important to be cautious and not confuse the difference between wall loss and pitting or flaw detection. It is important to note that the decline in speed applies to pitting; however, pitting is wall loss, but over a shorter interval of length. Wall loss to pipe inspection professionals normally refers to rod cut.

## ACTUAL FIELD EXAMPLES

The data for this paper is derived from three independent sources. First, rig data capturing information, KeyView®, was used to precisely monitor and record block speed from the beginning to the end of the scan jobs. Second, the actual scanned sensor data was downloaded and analyzed in detail. Finally, trained observers were situated on site to witness the jobs as they were being performed.

Figure 11 depicts what the service rig data looked like for one of the jobs witnessed. In this figure, there are four curves displayed. The first curve is hookload and it indicates that the rig is pulling out of the hole. The second curve is the rig engine RPM. The third curve is the block velocity. The fourth curve indicates the block position. The velocity curve supplies us with the information needed for this paper. This curve charts the rotational speed of the rig's tubing drum at any given time and is scaled in counts per second, and not feet per second. The rationale for counts, as opposed to feet, is based on the fact that rigs vary in drum core diameters and sometimes are tied back to a double fast line rather than a single fast line. The true block speed, which is averaged over a 4 second sampling rate, can be calculated knowing the rig and the configuration at the time of the pull. In the case of the sample shown in Figure 11, the rig was on a double fast line and on the initial pull off bottom, the block speed is reading 2,500 cps, which is just less than 4 feet per second. When the crew was nearly out of the hole, the block speed exceeds 8 feet per second on an average stand. A positive number on the block speed curve indicates the blocks are moving up and a negative number shows the blocks are going back down to get another stand. The block position curve on this figure shows the that the blocks move from the floor to the tubing board on each stand, which is an indication that no joints or tubing were laid down.

By referring back to Figure 9, it can be determined what happens to the resolution of the data when the speed was doubled. Illustrated in Figure 11 is the global job view perspective and when combined with Figure 9, it is the first indication of lack of data consistency due to the pull speed. At this point, because of block speed, there is some subjectivity involved in the interpretation of the data. The data in Figure 11 suggests sensor response and charting inconsistency; however, it may or may not translate into data invalidity. There was no apparent attempt to validate the technician's call of yellow, blue, green, or red and no attempt was made to determine what the upper speed limit was of the measuring equipment used.

A point by point detailed study of the block velocity data revealed another speed related problem. Figure 12 is a presentation of the foot-by-foot upward velocity of the tubing being pulled. In this figure, there are two separate pulls. The one on the left is data taken when a 60-foot stand of tubing is being pulled with a fairly heavy hookload. The Y-axis is the height of the blocks above the floor at any given time and the X-axis is the measured velocity at that particular block height. On every stand, the initial block velocity at the floor when the rig first starts the pull, is zero and it builds to 2.5 feet per second for a steady pull. This speed is held fairly constant up to approximately 50 feet. The problem is it takes 5 feet of tubing to get to the sustained speed of 2.5 FPS. In other words, the tubing goes from zero to 2.5 FPS in five feet. This creates inconsistent velocity as illustrated in Figure 12.

At the top, or end, of the pull and when the blocks are approaching the tubing board, the operator starts to slow down about 6 feet prior to a complete stop. At this point, the tubing velocity decreases from 2.8 to zero over a 6-foot distance. The slight increase in speed just above the 30 foot level is normal and due to two reasons: First, there are more wraps of tubing line on the drum so the block speed is faster per drum revolution. Second, the rig's transmission is going into lock-up eliminating any engine-transmission slippage.

In the scenario presented in Figure 12, the left-hand velocity profile was consistent for most of the scan job and the only variable that changed was the maximum speed at any given time: Slow on bottom with a heavy load and fast when the hookload was light. Velocity variations became more apparent as the operator began searching for the tubing anchor, which is illustrated in the right side of Figure 12. An unannounced TAC or packer suddenly appearing and being pulled into a wellhead or BOP is an unsafe and dangerous practice. Pulling a TAC into a scanning head is not acceptable. All operators work with safety as a paramount goal. When the operator knew he was getting close to being out of the hole, he would slow down near every collar and often stop as new a collar appeared under the inspection head. As soon as there was assurance that the TAC was not on the bottom of the joint being pulled, the operator would pick up the speed until the next joint or collar was coming up to the bottom of the head and then would slow down to a creep again.

This process varies from crew to crew, but for the most part, the rig crews are trained to slow down about five stands off bottom. It is a safety thing.

## WHERE IS THE BEEF? (OR, THE PROOF IS IN THE PUDDING)

API established general guidelines to grade pipe, which reads:

- Body Loss 0-15% — Yellow
- Body Loss 16-30% — Blue
- Body Loss 31-50% — Green
- Body Loss 51% Plus — Red

Procedures vary from operator to operator, but for the most part oil companies re-run yellow and blue banded pipe and junk the green and red. Figure 13 is a portion of a typical scan result, which is presented every day in the field. This is the standard work product of the scanning company.

The bars and color coded numbers above come from the scanning technician's calibrated eyeballs and from his or her field experiences. To be sure, these bars and color codes do not come from some sort of computation or algorithm. Actually what happens in real life is the rig pulls a stand of tubing through the head as the chart is running across the screen. While the tubing is moving, the technician looks at the amplitude of the peaks and valleys of the presented data and makes the call: Yellow, Blue, Green, or Red. He or she then enters the call on his laptop while the rig is standing back that joint of pipe. Then the rig pulls another stand and the process is repeated over and over until the job is over.

The job illustrated in Figure 13, 160 joints of 2 7/8" J-55 EUE were scanned out of the hole in three hours resulting in the following calls being made by the technician.

- 12 joints Blue due to Pitting
- 39 joints Green due to Pitting
- 2 joints Red due to Pitting.

The rig laid down a total of 41 joints due to "Pitting."

Figure 14 is an example of the actual scanned raw data from the job in the previous figure. At first glance, the upper scan marked 1 appears to be Green due to heavy pitting.

In joint number one, the high activity and intensity of the pitting curve was the catalyst for calling the joint green and the crew laying it down. There is no overly apparent rod wear. In the second scan, the pitting appears to be minimal and there is no rod wear to speak of. The challenge is whether to classify this joint as yellow or blue.

Actually, both of the scans above are from the same joint of tubing. They are just pulled through the scanner head at different speeds. The second scan is a slower pull, which can be seen by the width of the collar interference. Also, note the amplitude or intensity difference in the pitting curve as the collar comes through the head. Same collar, same joint. The only difference is the pulling speed. This anomaly is the direct result of what was discussed and illustrated in Figures 9 and 10. As illustrated in Figure 14, the apparent amplitude on the chart which is what the technician is looking at, is really “Change per unit of time” not “Change” and tubing deterioration is about change, not change per time. The difference here is a disconnect that affects the call of yellow, blue, green, or red.

Next in our study, we compared two different wells with similar histories which were scanned by two different service companies. The wells were located a few miles apart and were in the same field and reservoir. The two wells have the same size pumping unit, rods, stroke, tubing size, depth, and production, chemical treater, and the records indicate the tubing was close to the same age.

Figure 15 illustrates a comparison of these two scan jobs. The top of the illustration is a segment of the scan report (final work product) of each well showing the grade of pipe found in the well. Just below the scan report is the KeyView® velocity chart.

Well number one on the left was scanned with the technician grading the entire string of pipe as yellow. He found no joint of pipe to have pitting in excess of 14%. Dropping directly below the scan report and looking at the KeyView velocity profile, the data indicates the scan was performed with block velocities starting at 4.1 feet per second and building to 9.3 feet per second.

The second well, on the right side of Figure 15, was scanned three days later. This technician found no yellow, 12 blue, 39 green, and 2 red joints due to pitting. From the KeyView data, the speed of the pull on this job ranged from 1.8 feet per second to 5.3 feet per second.

By reviewing the history of the two scanned wells, it is apparent that something is amiss with the data on well number one. The two examples are identical wells in the same field and at the same depth. They differ only in the amount of reported pitting and corrosion.

A potential reason for the lack of data quality on the left well may be explained by a mathematical model comparing sample rate to length of pipe scanned per unit of time. Suppose a joint of tubing has a 1/16-inch hole in it. This means that over a gross interval of one foot of pipe, there is a possibility of 16 holes per inch times 12 inches per foot stacked end to end. The hole therefore could be at [16 X 12] or at 192 different locations. Essentially, number of locations per inch is infinite; however, for this example, the point can be made using the number 16. If the tubing in being scanned at a rate of six feet per second, the number of possible locations of the hole passing under the head every second is:

Possibilities = [6 Feet/Second) X [12”/ft] X [16 locations/inch] = **1,152 possibilities**

Using the same logic, if rig was pulling the tubing at 4 feet per second, there are 768 possibilities of hole locations per second.

Unfortunately, that is not what happened on the first of the two wells in Figure 15. That tubing was being pulled at 9.3 feet per second and the math calculates the possibilities as follows:

Possibilities = [9.3 Feet/Second) X [12”/ft] X [16 locations/inch] = **1,785 possibilities**

As stated earlier, the processing speed, or scan rate, of an electronic device is similar to the shutter speed of a camera. The equipment can only look at an interval, or take a picture so fast. The processor rate of the equipment in use that day is less than 500, which means that the technician had approximately a 33% chance of seeing the 1/16” hole at that high rate of speed. Remember, all he saw was yellow.

Mr. Gates has provided the electronic world with an excellent tool in the form of Excel® that further illuminates the speed problem disclosed in Figure 15. Scanned data points from both wells were stripped-out of the normal service company presentation and charted in an Excel format shown below. The idea was to count the number of actual data points (or pictures so to speak) taken in one joint of pipe by the equipment as the rig pulled the joint at different speeds.

Each of the Excel charts in Figure 16 depicts one length or one 32-foot joint of pipe between the vertical peaks. The vertical data comes from the flaw detector or Hall Effect sensor voltage and the number of data points is plotted and numbered in the X-axis. To the scan technician, visually the curves might look the same; however, there are two striking differences:

- The number of data points in scan 1 between couplings is 1,300 and the number of data points in the joint scanned on scan #2 was 3,150.
- The voltage intensity of the peaks on scan #2 is twice as much as the voltage response on scan #1

This joint of pipe was 32 feet or 384 inches long. Using the Excel data from scan one we calculate:
1,300 data points/384 inches, or 3.4 data points per inch, or one data point 1/4 inch of pipe.

On scan #2, a total of 3,150 data points were taken over the 384 inches of pipe. This calculates as follows:
3,150 data points/384 inches or one data point for each 1/8 inch of pipe.

It should be fairly obvious at this point why all the pipe in well #1 was yellow.

Oil companies typically scan and adjust their tubing strings based on the color code.
Missing the call between yellow and blue only drives the chemical man insane. It costs nothing. Missing the call between blue and green drives operating cost up as now the tubing is replaced, trucked, and sold. The expensive Blue-Green call by the technician is the call that really is “Gray” due to speed.

## THE SPLIT

Electronic tubing inspection equipment cannot identify splits in the tubing. As previously illustrated in Figure 2, the flux lines run inside of and longitudinally to the axis of the pipe. When the flux lines see a split along the axis of the pipe, they will bend a bit but continue on running longitudinally. Since the Hall Effect sensors are mounted perpendicularly to the magnetic flux lines within the pipe, they are not affected by the flux lines and will miss the change. The flux density has not changed. It merely moved. The wall thickness detectors will not see a longitudinal split if there is no wall loss so the equipment designers needed a way around that dilemma.

In an attempt to get around this challenge, equipment designers have devised a canister that surrounds the pipe being inspected. At each end of this canister, a wiper rubber is placed to seal the space between the canister and the pipe creating a confined annulus. The idea is that if constant air pressure were applied to the “split detecting annulus device”, any hole or split in the pipe passing through the device would allow air to escape from the canister into the center of the pipe. Therefore, monitoring the pressure in the split detector should be an indication of a split. That is a good theory, but unfortunately it doesn’t work well at fast speeds.

Think about if the rig is pulling tubing at 4 feet per second, the 1/16-inch hole or split is in the canister for ¼ of a second. There is not much air loss and it is doubtful any pressure change could be seen.

## HYDRO-TESTING BACK INTO THE HOLE

Some companies may prefer to find leaks using a hydro-tester while others have a policy to hydro-test back into the hole after they have scanned the tubing. The rationale for this range from ensuring coupling tightness; the scans cannot measure within a foot of the collar; and non-confidence in the scanned data. All these stimuli are understandable.

Simply stated, running a hydro-test or pressure test follows the scenario below:

1. Run the stand of tubing into the hole.
2. Lower the test mandrel and pressure up the connection with water.

3. If the operator observes a pressure gauge drop, the joint is leaking and the rig lays it down.
4. If the operator does not observe a pressure gauge drop, run another stand and repeat the process.

You are encouraged to witness a hydrostatic job and observe the gauge they use for a test. The pressure drop for a pin-hole leak is a needle width. This being said however: The key phrase in the "Pass-Fail" procedure is: "If the operator observes?"

Figure 17 is a portion of actual data taken on a hydrostatic tubing testing job. To start with, the testing company was given instructions to test the 2 3/8" J-55 tubing to 7,000 psi. Figure 17 conveys the facts of test: Some of the joints were tested to just over the target of 7,000 psi. Some the joints were tested to over 8,000 psi. The data in Figure 17 highlighted the problem where maximum recommended pressures were exceeded as the specifications on 2 3/8' J-55 EUE pipe list the internal yield pressure at 7,700 psi.

The second quality hurdle appeared during the "hold to see if it leaks time." Figure 18 illustrates four different stands of tubing tested on this job. Each dot in the figure represents one second of time and each of these "pressure ups" is taken at random. The data reveals the following:

- Stand #1 was tested to 7,950 psi, observed for one second and no leak was found.
- Stand #2 was tested to 7,200 psi, observed for one second and no leak was found.
- Stand #3 was tested to 8,080 psi, observed for two seconds and no leak was found.
- Stand #4 was different. This pressure was observed for 12 seconds as the operator had an observer in the truck as a witness. The pressure went to 7,280 psi and bleed to 6,923 in 12 seconds.

For the record, it is difficult to determine from any API publications what defines a leak when field hydrostatic testing, but the best guess might come from API 5C or 5CT which when paraphrased reads:

- The pressure hold time shall be a minimum of five seconds after the gauge indicator has reached its maximum stable pressure value.
- Any observable bleed off in pressure over a 5 second hold time in is a failure.

If you apply API 5C to the fourth connection above, the loss of pressure would be:

[7280 – 6923] or [357 psi] / [7280 psi] = 4.9%

This joint or test lost 4.9% of the pressure in 12 seconds. It, by the best definition API is leaking.

Of course, the other question or issue is: "How about stands 1, 2, and 3? The truth is: nobody knows. They were not held long enough to determine anything other than the fact they did not split a collar and fall into the hole.

## CONCLUSIONS AND SUMMARY

During the course of gathering data for this paper, we observed many jobs using different rig crews and four different scanning companies. We found that none of the four scanning companies had a reference or interpretation manual to hand to their clients. We found that only one company provided formal training for the technicians. The other three technicians were taught by on the job training.

Techniques and procedures differed among the four scanning companies represented. Three of the technicians shut the rig down intermittently and got out of the truck to look in the pipe with a mirror to confirm their findings. Two of the companies could measure the speed of the pull. Two could not. Of the two that did not measure the speed of the pull, one technician slowed the rig down after he "observed or thought" the rig was too fast. The other technician failed to caution the rig they were too fast even though the rig was pulling pipe at well over 8 FPS.

We did not find any of the scanning companies to have a good knowledge of lower speed limits and or speed profiles; however, three of the four were aware of some upper speed limit which they could not define in hard numbers. Two of the four companies calibrated their equipment prior to the job. Two did not calibrate their equipment.

Unfortunately, no company man or consultant witnessed any of the tests or jobs. Furthermore, no one ever questioned the service technicians about their data.

The purpose of this paper is to understand how to effectively scan and grade tubing in the oilfield and to find ways to improve our decision making data. As a result of our study, we would recommend the following areas be examined.

1. Technician Training: Training must focus on communicating all the good habits and good techniques but it must also communicate the weaknesses and strengths of the measuring systems. Today we use on the "on-the-job" and "hand-me-down" training approaches. No doubt on the job training is an important and integral part of sharing the knowledge in the industry. However, we need to recognize that this alone also trains for and passes on poor techniques and knowledge gaps.

2. Collaboration: The industry must work in collaboration with all the various segments that affect the data quality. Consistency and uniformity in the data interpretation will only be obtained when the service companies work in unison.

3. Supervision and Oversight: The industry service providers must be accountable for the data that is being produced. Oil companies must question and ask. Oversight is an integral part of Quality Control.

That nebulous concept of "scanning interpretation is the combination of an art form and science" was mentioned by all four service providers. This issue must be addressed. The movie industry, museums, and even an occasional architect make money on art forms. The oil industry has not done too well with art. We must standardize the data and techniques, and applications. The "Blue-Green" decision is a costly one. Wrong one way is promoting a well failure; wrong the other way is wasting money on replacement tubing. The cross between blue and green is a gray line. We can tighten up that line by working to standardize our work in the field.

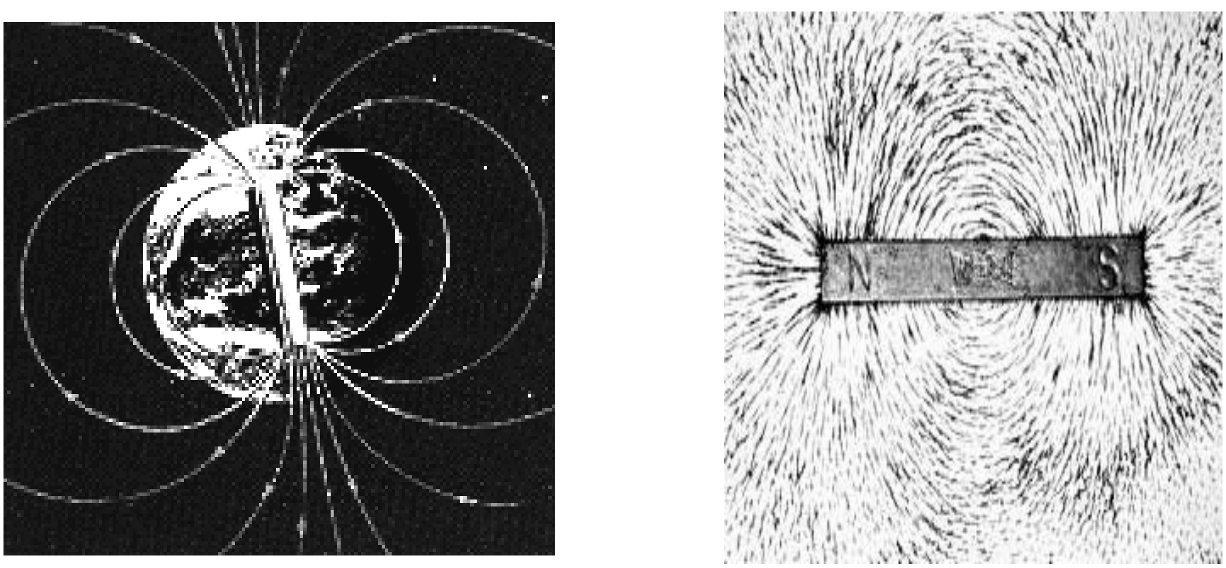



Figure 1

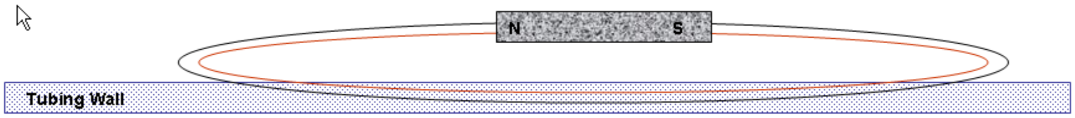



Figure 2

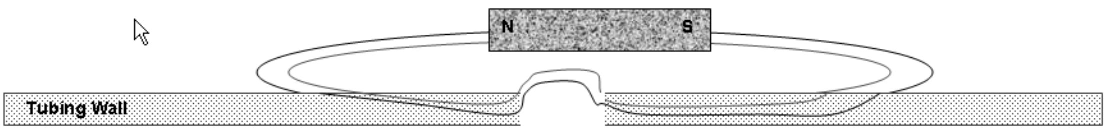
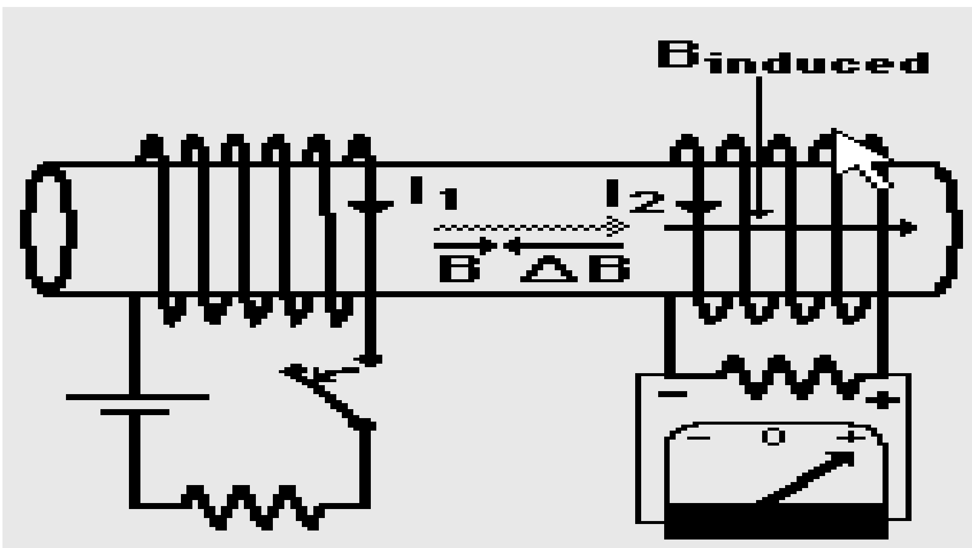



Figure 3

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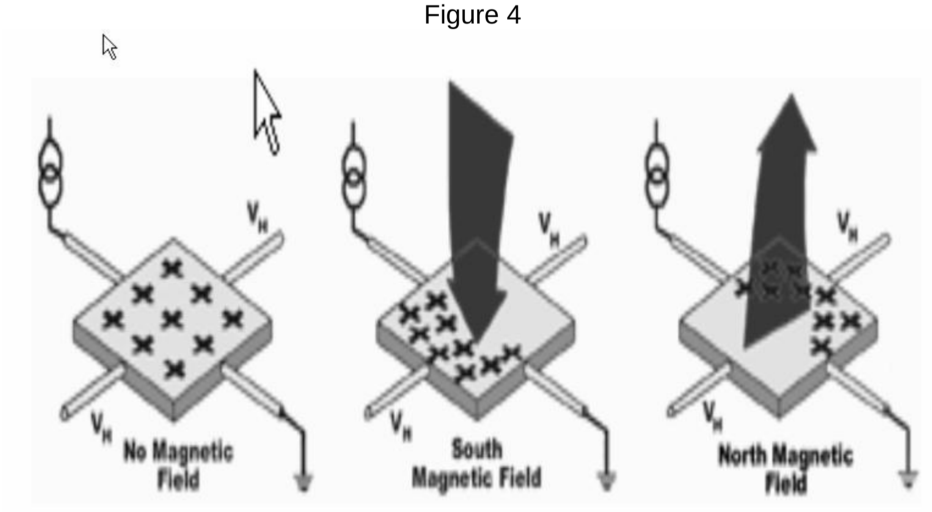


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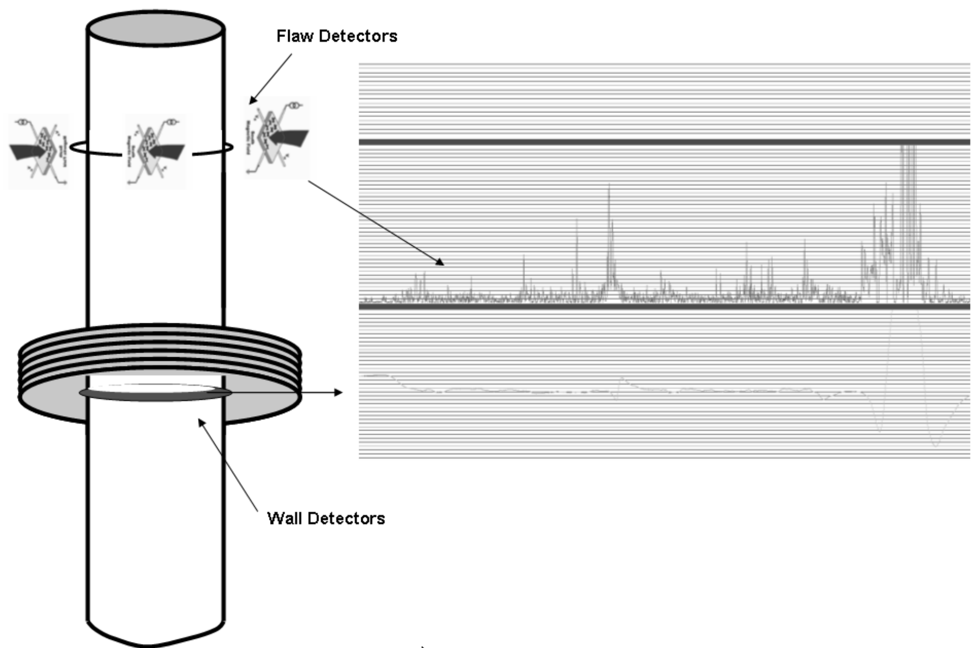
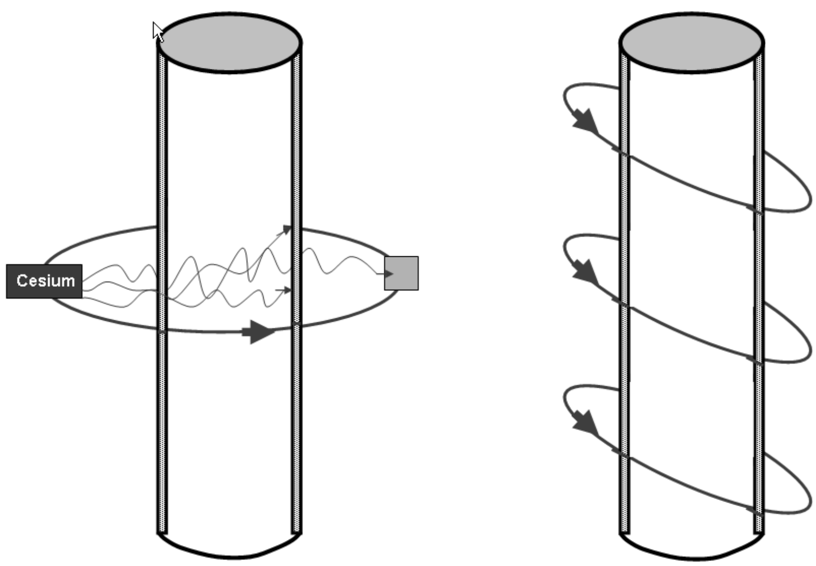



Figure 6

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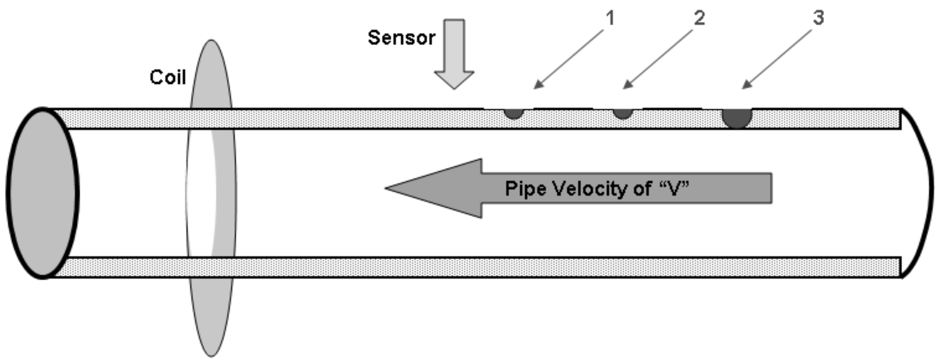


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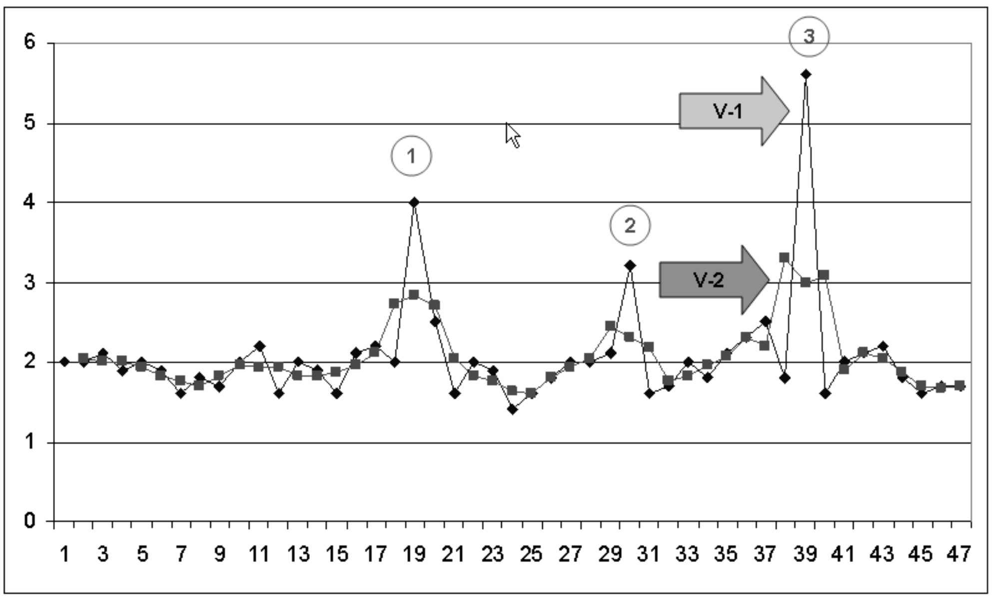


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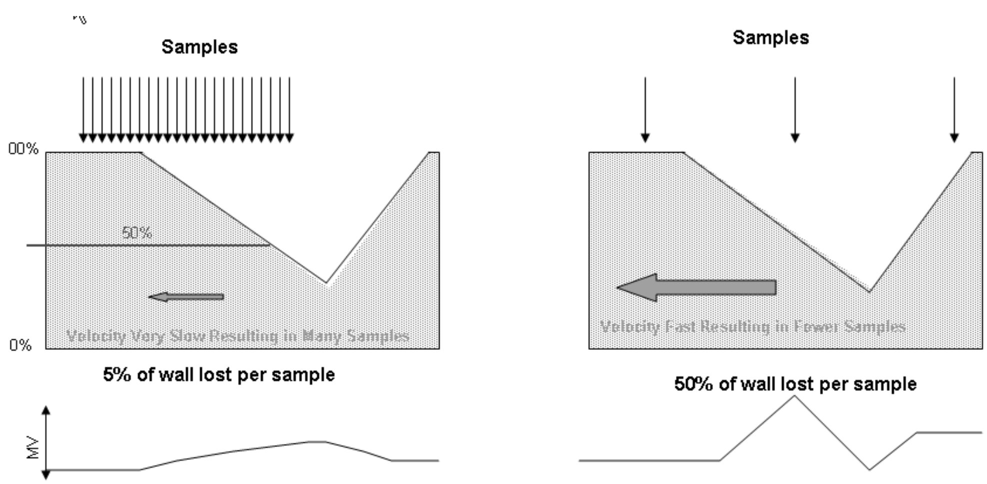


Figure 10

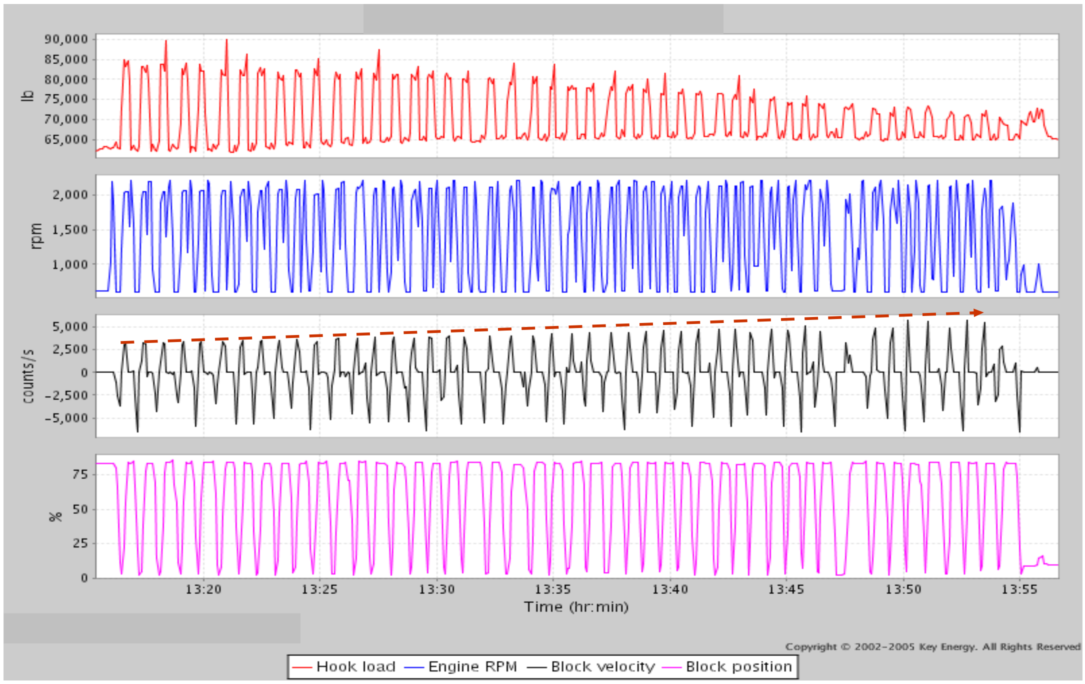


Figure 11

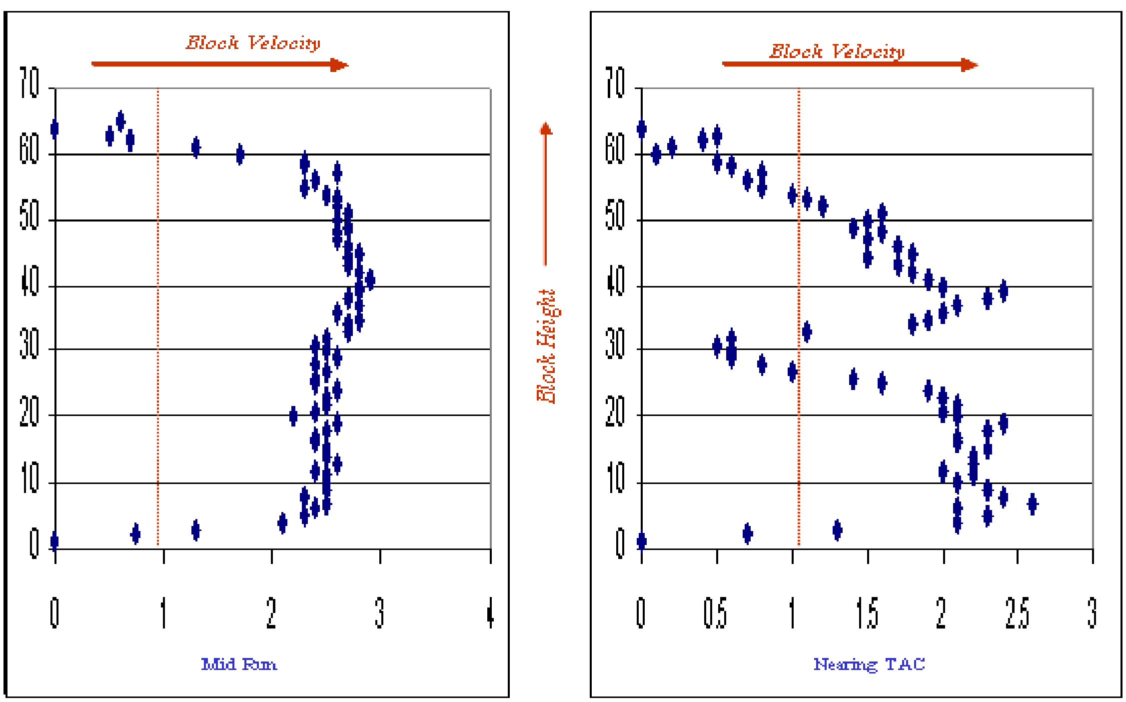


Figure 12

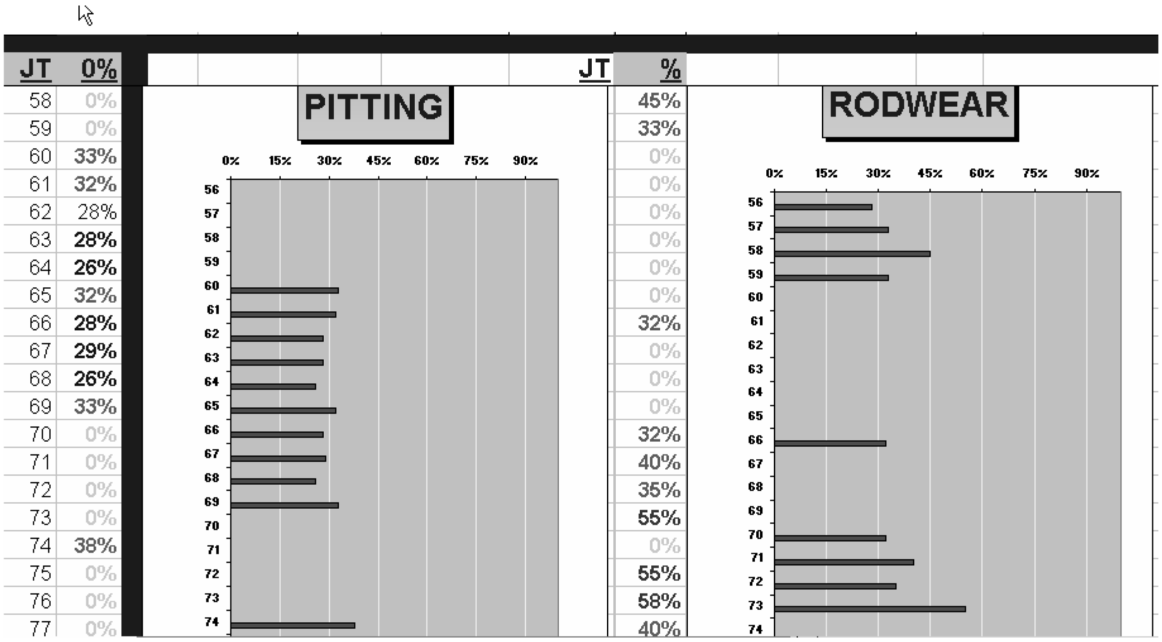


Figure 13

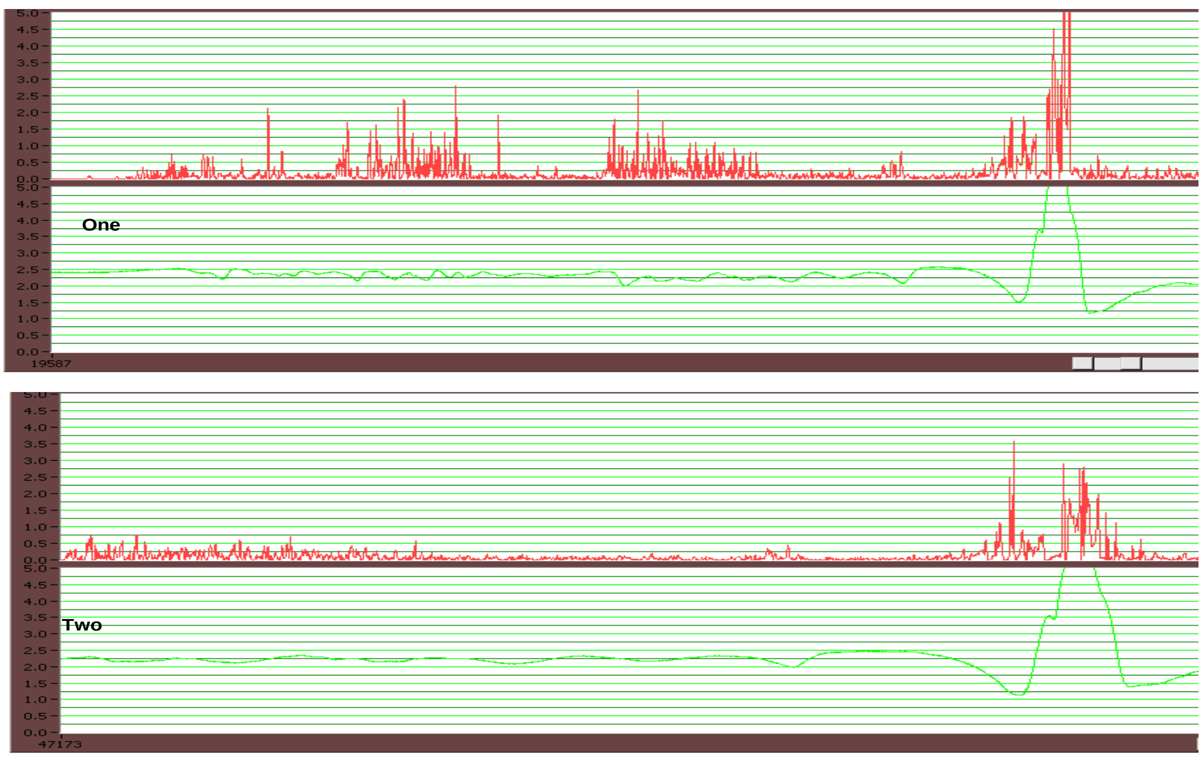


Figure 14

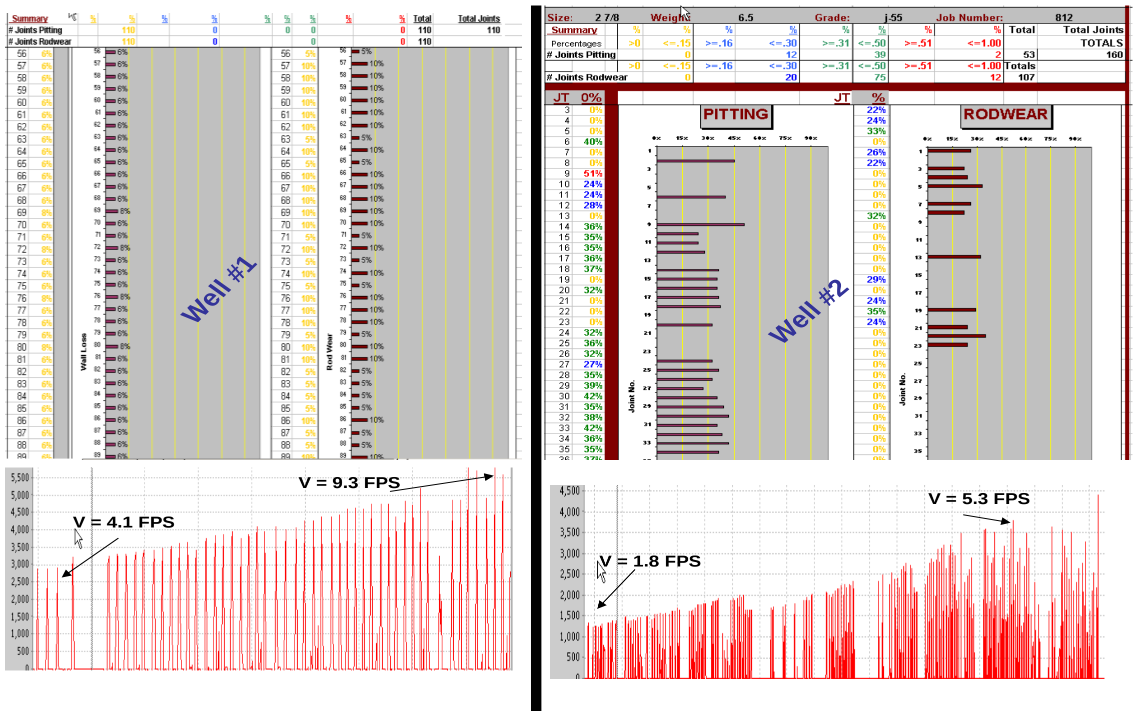


Figure 15

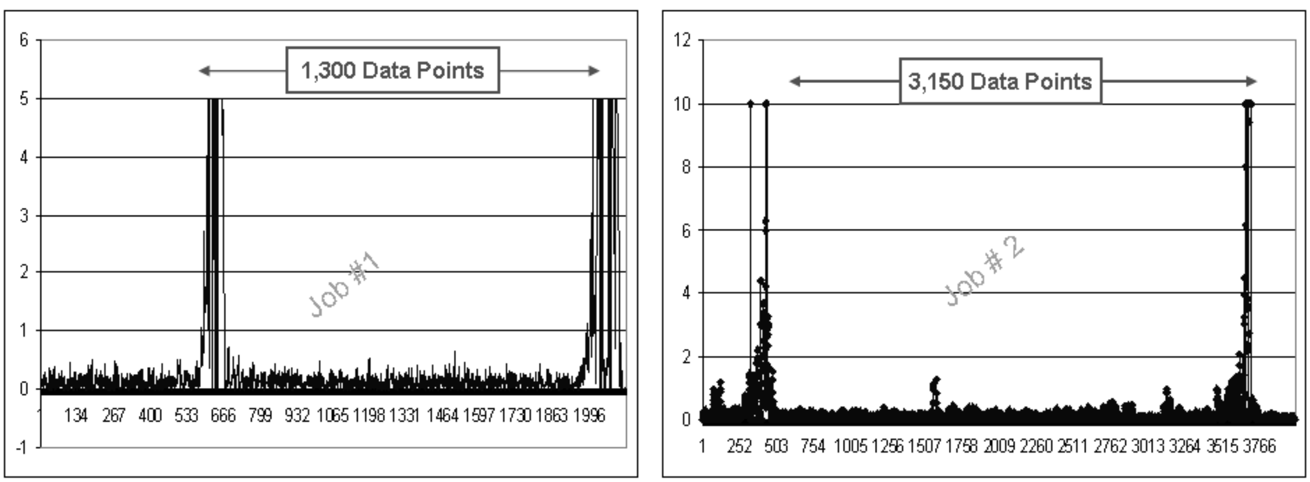


Figure 16

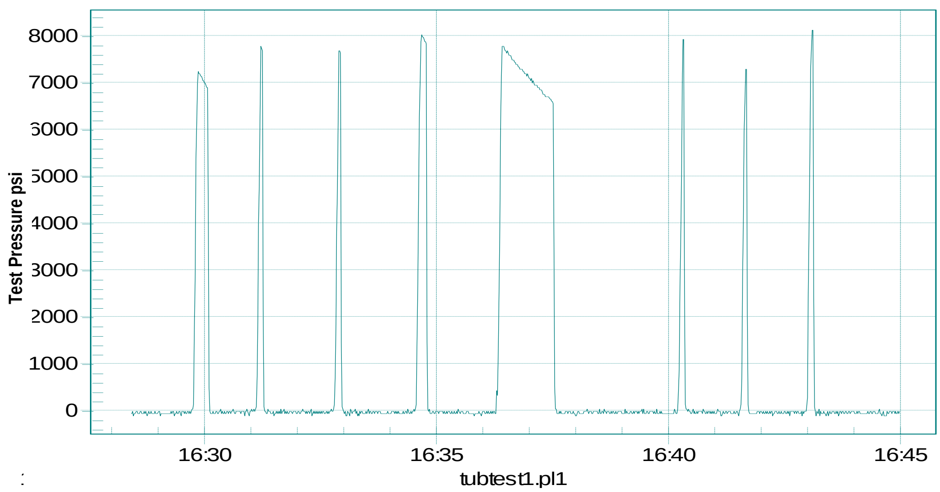


Figure 17

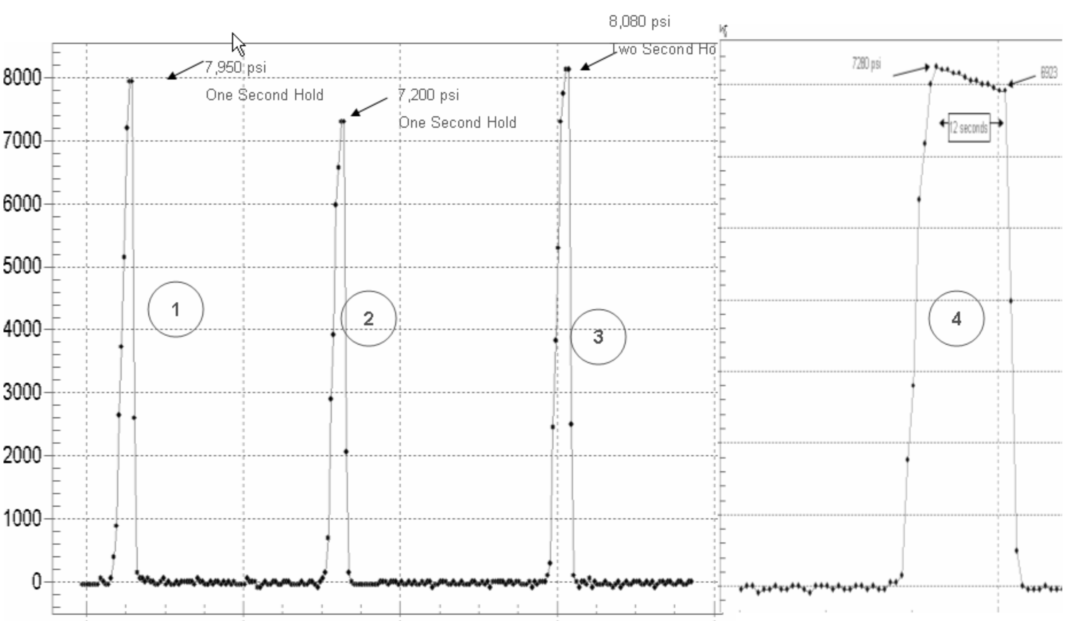


Figure 18