WELLHEAD SCANALOG

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In spite of today's bargain prices for tubular goods, the recovery and reuse of existing tubing provides a highly cost effective pipe stock. Most operators appreciate the value of some screening process to remove unsatisfactory tubes before they can contribute to another workover shortly after being reinstalled in a well.

Several techniques exist to assist the operator with this screening. They range from a simple visual examination of the tube to a very sophisticated ultrasonic rack inspection. In order of rank, these would include:

Inspection	Quality	Cost
Visual	Least	Lower
Hydrostatic		
Caliper		
EMI		
Ultrasonic*	Best	Highest

*Not available for used tubing.

The limitations of the visual technique are obvious. Only the most glaring of defects can be found. This process is usually reserved only for the threads where severe mechanical damage (Galling, Flatening, etc.) is expected. Even the use of a magnifying optiscope is not productive unless significant cleaning is done prior to inspection.

Hydrostatic testing is an excellent technique for evaluating threads and locating holes in pipe. It is quick and relatively inexpensive but is not quantitative. It does little to screen from the well pipe on the verge of failure. The force required to cause burst in a worn length is the product of the pressure times the area. Hence small defects, such as corrosion pits or rodworn thin spots, may hold test pressure but fail rapidly, e.g. within 30 days, when returned to the corrosive or abrasive environment.

Elevating the test pressure will produce a more severe test but does little to prevent premature service failure since the other variable (defect area) remains unknown. In addition hydrotesting adds significant rig time if done in the well or transportation cost if done in a yard.

Mechanical caliper surveys are relatively inexpensive but can exhibit poor accuracy if a pit is positioned between the feeler gauges. It too adds significant rig time for calibration and test runs. These are also blind to O.D. defects and may be disabled by scale or paraffin deposits on the pipe I.D. In many cases extensive cleaning of the well bore is required to enhance accuracy, further inflating costs. In some cases, calipers have been observed to destroy the protective inhibitor or natural film on the pipe surface, resulting in accelerated corrosion in the feeler tracks.

Ultrasonic units offer a highly accurate inspection technique but may be cost prohibitive when factors such as extra cleaning and transportation are considered. In addition, significant rig time is added to the workover when required to breakout and lay down each joint in a string. The major technical problem is coupling the ultrasonic transducer to the rough surface of a used tube. This is much easier to accomplish on new pipe and hence this technique is currently restricted to new goods.

Of all the techniques considered, electromagnetics seem to offer the optimum balance between cost and technical capability for inspecting used pipe. It is quantitative, allowing the grouping of pipe into service categories based on wall loss. This in turn permits the operator to select which categories he wants to return to the well. It is accurate since coverage in excess of 100% of the tube body is provided both longitudinally and transversely. It detects both ID and OD wall loss, usually without any special, costly cleaning. Finally it is safe and non-damaging to both personnel and steel.

Historically the principal disadvantage of this service has been the cost. The extra rig time needed to break joints out in singles plus the extra pipe handling required to transport and move lengths in a storage yard contributed to this high cost. All of these obstacles have been overcome by developing a special EMI unit that performs during the pulling operation. Pipe can be pulled in doubles and racked back if approved for continued service. No additional handling, beyond normal workover crew requirements, is needed. Subsequent operations, such as cleaning or pressure testing of threads, can be performed on good footage only. Since inspection results are known as soon as each joint clears the slips, replacement pipe can be delivered while the workover is being completed, thereby eliminating any delays in rig time.

The name of this unique new service is the Wellhead Scanalog. The equipment consists of two components:

1. The wellhead assembly is 30-inch high x 44-inch diameter and weights 2200 pounds. It is flanged on both ends to mate to the BOP or wellhead assembly on bottom and the slip bowl on top. Inside this head is a smaller electronic package which contains all the sensors used to search the pipe for defects. This electronic package "floats" between two hard rubber wipers which are the only contact points with

the steel. These wipers keep the electronic sensors centered on the tubing as it jerks and tilts being pulled from the well. The inspection head is connected to the logging trailer by 200 ft. of umbilical cable to permit remote positioning of the trailer on tight locations.

2. The logging trailer consists of an air conditioned operator's compartment and electrical generator. The inspection is monitored from this trailer by one of the two man crew. In the operator's compartment, logs are read, inspection classification determined, and instructions issued to the outsided crewman to properly identify and segregate each joint or stand. The operator is assisted by five on-board computers which analyze the data from the sensors and display it on a four channel strip recorder.

A typical job would begin with the workover crew lifting the wellhead assembly out of its traveling harness and "stinging" it over the uppermost joint in the string so it can be bolted to the BOP or wellhead flange. Next the slips are positioned above the electronic assembly and the rig floor swung into place.

Calibration is accomplished by screwing a known joint of equal diameter to the top of the test string. This reference joint need only be sufficiently long to pass completely through the electronic package while hanging in the elevators (usually 4-5 feet). Each unit carries its own reference samples. The sample is hung in the sensors and the computer readout adjusted to reproduce known values. The sample is rotated in quarter turn increments to activate multiple sensors. Once set, the magnetic sensitivity cannot be altered by the operator. Should the magnetic field change during the job, it would be immediately obvious due to baseline drift on the electronic log. Electrical repair and/or recalibration would be required to reactivate the inspection sequence.

Total time for set-up and calibration is usually 30 minutes. Another 15 minutes is required for rig down following the job. Therefore this test only requires 45 minutes of additional rig time.

Once in operation the equipment is essentially invisible to the rig crew. They operate in their normal manner, pulling as slow or as fast as they desire (up to 400 feet per minute). A small tattletale pulley on one of the fast lines from the elevator is used to measure the pulling speed. This measurement is relayed to the control computer which adjusts the chart speed. This produces a constant 6 to 7 inch chart length per tube and hence defects can be located accurately along the length of the tube.

Whenever possible, guidelines are established before the start of the job regarding what quality or pipe is acceptable to run back downhole. When pulling, pipe in these categories are racked in doubles, greatly reducing rig time. Only those joints in a category defined as unacceptable are broken out singlely and laid down.

As the pipe is pulled through the sensor package, three independent inspections are being performed simultaneously:

1. An eddy current field is induced on the surface of the steel, scanning for holes and/or splits. This inspection is especially sensitive to deep defects, i.e. over 70% wall loss. A special electronic technique is used to mask the coupling signal, thereby permitting inspection of the upset right up to the coupling.

2. The unknown tube is saturated with magnetism and scanned for flux leakage indicating either rodwear or pitting. The search detectors do not have to contact the steel wall (as required in conventional "Rack" type EMI equipment) so no special cleaning of the pipe surface is required. Since nothing is positioned inside the pipe, the presence of scale, paraffin, or other deposits does not interfere with the inspection.

In order to optimize reliability, it was decided early on that the mechanical rotation normally required to achieve the circular magnetization necessary to detect rodwear could not be tolerated. In order to exist in the wet and dirty environment beneath the rig floor it was necessary to eliminate all moving parts. This was accomplished by precisely arranging a magnetic array around the tube in a design based on finite element analysis. The computer activates each electromagnet in sequence, and does it so rapidly that magnetic motion is achieved without mechanical motion.

3. Finally the cross sectional area is measured and, using the known O.D., the average wall thickness is displayed. This flags areas of uniform wall loss, such as erosion, and different weight joints. The real significance of this is that the computer can correlate the pitting and/or rodwear loss with the average wall at each point on the tube. All conventional EMI units assume such defects occur in areas of nominal wall.

The accuracy of the inspection provided by the Wellhead Scanalog is comparable to conventional EMI units. This in spite of the fact that Wellhead inspection takes place at normal pulling rates, often 30-40 seconds per joint. Conventional rack EMI, with visual and manual prove-up may require up to 3-4 minutes per joint. Based on samples which have been cut open behind the Wellhead Scanalog, sandblasted, and defects measured by micrometer, the indicated value is usually within 5% of the true value.

For this reason pipe is classified by a color code indicating a range of wall thickness. Each operator is free to choose limits best suited to his needs but many follow the recommended practice or API RP 5C1.

In one well documented case, the Wellhead Scanalog inspected 74 joints of 2-7/8 inch, 6.50 lb., J55 tubing in approximately 90 minutes. The same pipe was subsequently reinspected by a full fourfunction rack unit requiring 5-1/2 hours. Total agreement between the two inspections was recorded on 74% of the joints. Fifteen of the disputed 19 joints were found to lie within the 5% tolerance limit on the borderline, resulting in a one color band discrepancy.

In another test a joint was mapped using compression wave ultrasonics following the Wellhead Scanalog. Figure 1 shows the excellent agreement between the two methods. At the deepest point, the Wellhead indicated 61% wall loss while ultrasonics show 62%. The EMI scan required less than five seconds. The ultrasonic mapping took almost two hours.

The benefits of Wellhead Scanalog inspection go beyond the immediate need of screening undesirable pipe from continued service. Since the inspection is performed in real time, the results can be plotted as shown in Figure 2 and Figure 3 to yield a profile of the well. As the log follows the exact sequence of pipe in the well there is no possibility for mis-numbering or confusing the data.

Figure 2 shows a definite problem with the inhibitor, which was being added by a batch dump process, not reaching the bottom of the well. Figure 3 indicates four specific areas of rodwear, probably due to crookedness in the well bore.

In yet another application the Wellhead Scanalog was used to monitor corrosion rates and inhibitor effectiveness in a group of West Texas wells. The strings were scanned at four month intervals and data on wall loss measured and plotted. The rig crew exercised great care to reposition each tube in the same sequence between inspections. Due to the accuracy and repeatability of the Wellhead Scanalog, the operator was able to monitor the growth of individual areas of corrosion within the well. Adjustments in chemical treating programs could also be measured for effectiveness. A large amount of statistical data can be gathered under actual field conditions.

In a California well, it was determined that the operator required a more flexible coating in his injection well. This conclusion was based on the high incidence of corrosion at the slip and tong locations compared to the rest of the tube.

Other changes that operators have implemented based on data provided by the Wellhead Scanalog includes:

1. Installation of tubing anchors.
2. Spotting of Rod guides.
3. Alteration of inhibitor program.
4. Spotting of inhibitor.

When this data is acted upon, a significant savings in pulling costs can be realized. In one West Texas application pulling frequency was reduced from 3 months to 18 months as a result of corrective actions initiated on the basis of inspection data.

In summary, the Wellhead Scanalog is an efficient and economical method for obtaining quantitative information about string performance. It provides accurate and repeatable data about ID and OD defects, without costly cleaning, rig crew delays, or transportation and yard handling. It enables the operator to select which pipe will be returned to the well for continued service. It can also provide the basis for changes in string design as well as monitor the effectiveness of these changes. It can significantly reduce workover costs by lengthening frequency between pulling jobs.

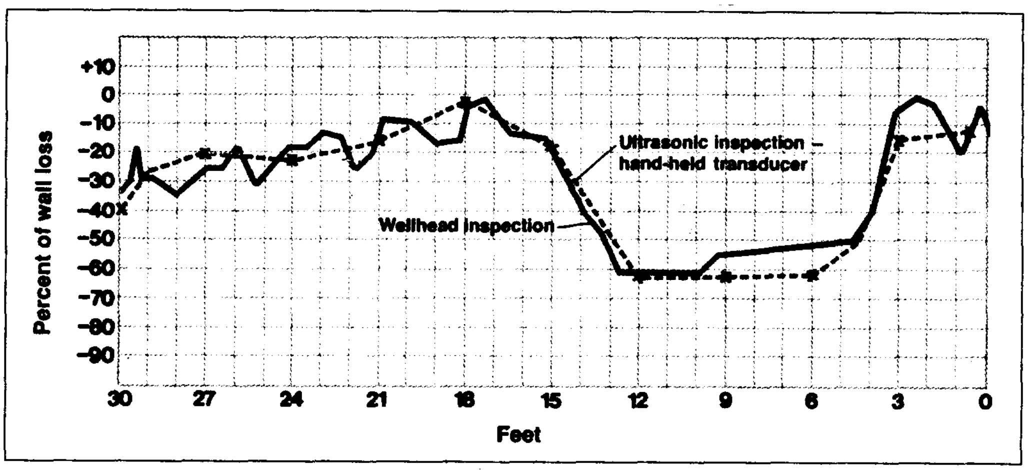

Figure 1 — Comparison of Wellhead Scanalog and ultrasonic inspection

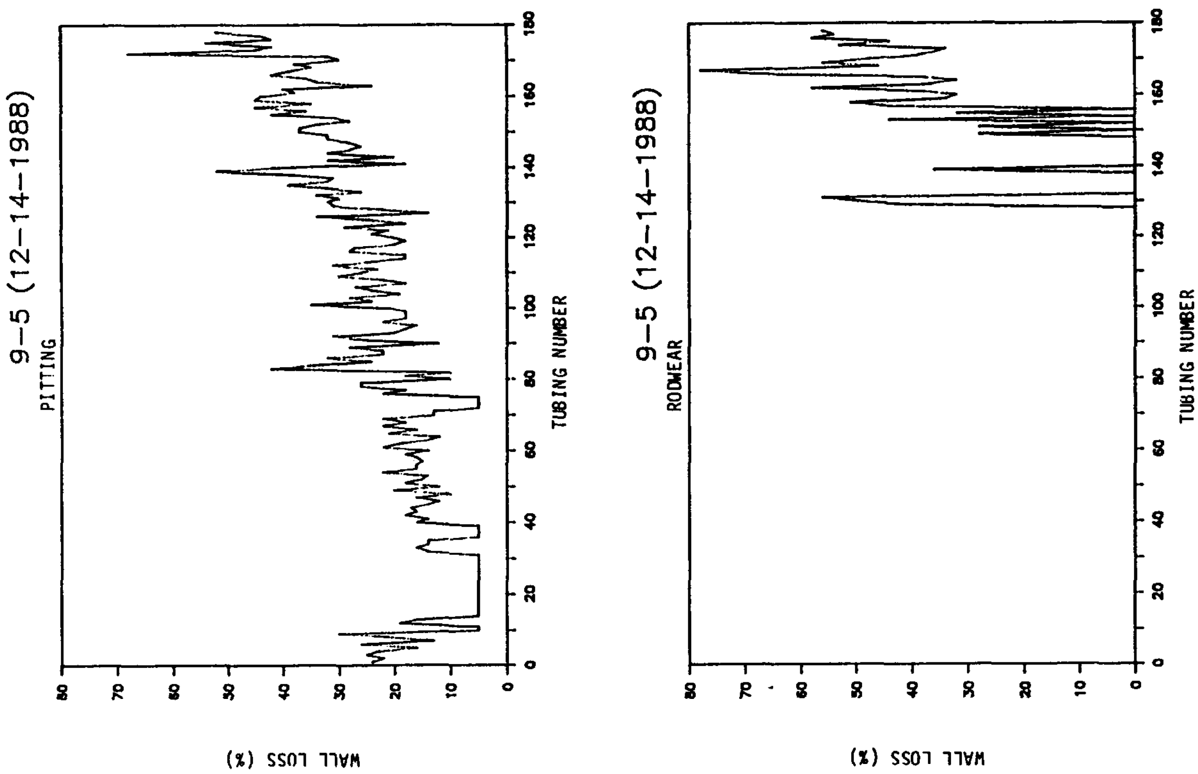

Figure 2

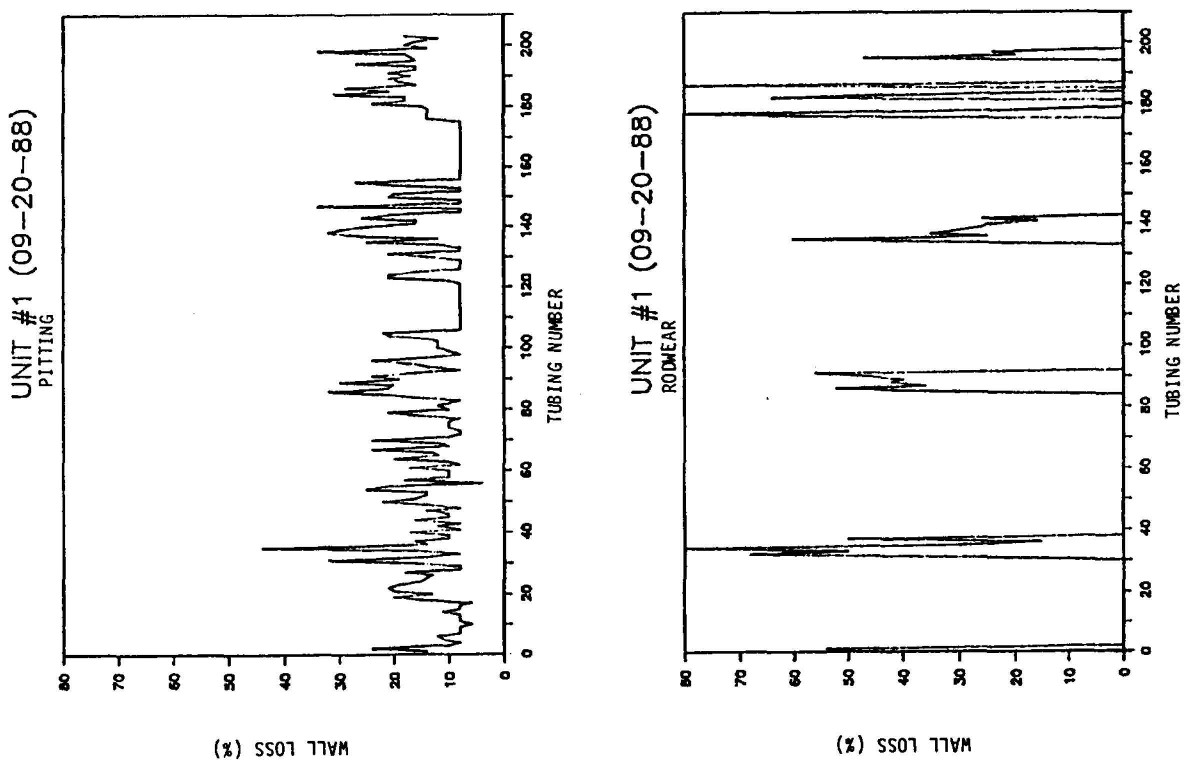

Figure 3