ROD GUIDE STRATEGY FOR SUCKER ROD PUMPED WELLS IN THE EAGLE FORD SHALE

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ABSTRACT
Murphy currently operates more than 600 wells in the Eagle Ford Shale. Currently 500 wells are on sucker rod pumps (SRP). The first Murphy SRP was installed during 2012. The challenges to SRP operations in the Eagle Ford include paraffin, corrosion, solids, deviated wellbores, slug flow, and foamy, gassy fluid.

Deviated wellbores contribute to failures in the tubing and sucker rod string. Failures occur because of metal to metal contact between the sucker rod coupling and the tubing. The development of a rod guide strategy has reduced the failure frequency of tubing and sucker rod couplings.

The rod guiding strategy was developed using the failure data base, tubing scans, deviation surveys, and rod guiding software.

INTRODUCTION
Murphy Oil Corporation chose sucker rod pumps (SRP) to produce the unconventional Eagle Ford Shale located in South Texas. The SRP system is one of the methods of artificial lift that can produce the well as the reservoir pressure declines and the production rate decreases. SRP are a well-known technology. It is reliable, versatile, and has reasonable OPEX.

The challenges of producing the Eagle Ford wells include paraffin, corrosion, solids, deviated wellbores, slug flow and foamy gassy fluid. The challenge of deviated well bores led to the development of a rod guide strategy for Murphy Oil Corporation.

TUBING FAILURES
Murphy's artificial lift team developed a failure data base. The data base tracks the installation details and failures in the sucker rod pumped wells. The data base documents the failure by component and the root cause of each failure. The components are the pump system, sucker rod system and tubing system.

The tubing system includes the tubing, pump seating nipple and chemical injection mandrel for cap strings. Holes in the tubing comprise 64% of the total tubing failures. (Fig. 1) The holes in the tubing occurred in 9.4 % of the operating wells.

A probability distribution of the run days to hole in the tubing was plotted for the wells with a hole in the tubing. The average hole in tubing occurred in 298 days. A probability distribution of the depth to hole in the tubing was plotted for the same wells. There is no correlation to the depths of the holes in the tubing. (Fig. 2)

Tubing failures have occurred in 90 % of wells with either a completely slick rod string or a partially guided rod string. The tubing failures in this group of wells occurred 100 % of the time where slick sucker rods were installed. The other 10 % of failures happened in wells with guided sucker rods. A hole in the tubing developed where the rod guides failed. The loss of the rod guides allowed sucker rod coupling contact with the tubing. In the other cases, guided rods were installed in a well which already had wall loss in the tubing. This wall loss was due to sucker rod coupling contact caused by operating slick rods in the well.

The two items which fail when sucker rod couplings contact tubing are the coupling and the tubing. The coupling will fail because of metal loss. The coupling wall becomes so thin that the pin will pull out of the coupling and the coupling will part. (Fig. 3)
The sucker rod coupling can become worn flat on one side. (Fig. 4) When the coupling wear is severe then wear is seen on the shoulder of the rod. (Fig. 5). Wall loss in the tubing is expected when the sucker rod couplings and rod shoulders contact the tubing. Murphy does install rod rotators on all of the SRP wells. The rotation of the rods distributes the wear around the rod guides or sucker rod couplings in slick rod strings.

ROD GUIDES

Guides installed on the sucker rods is an effective method to mitigate wear on the tubing. Different models of rod guides are available in the industry. Some models of rod guides are not suitable for the deep, high temperature conditions found in the Eagle Ford.

Molded guides are recommended for Eagle Ford wells. This type of guide is injection molded at a plant. The factory installed guides maintains a strong bond to the rods. Two types of guide material have been used in the Eagle Ford. Polyphthalamide (PPA) and polyphenylene sulphide (PPS) is the raw material currently used by guide manufacturers. Murphy has experienced failures of rod guides containing PPA material. A modified PPS guide material is now installed in Murphy wells.

The guides must be installed and spaced correctly on the rod. The guide closest to the coupling should be approximately 12 to 16 inches from the pin end. This spacing allows room for proper rod make-up. The number of guides per rod is determined for specifically each well. The number is based on the calculated side loading from rod design and rod guiding software.

Erodible wear volume is the amount of guide material available to wear before the coupling comes into contact with the tubing. The larger the rod the less erodible wear volume is available because of the stand-off between the larger sucker rod coupling and tubing. One inch rods require more guides per rod to prevent coupling contact with the tubing. (Fig. 6)

DEVIATION SURVEYS

The drilling process includes deviation surveys. This survey documents the path of the wellbore from the surface to the producing horizon. Rod pump design programs use deviation surveys to graph the distance the well deviates from true vertical in the east – west and north – south direction. The looking down trajectory graphs the well path if viewed from the surface. Well trajectory for two typical Murphy wells shows the vertical sections are deviated. In one of the wells the wellbore deviates from vertical by 40 ft. to the east. (Fig. 7)

Rod pump design programs calculate dogleg severity (DLS) and side loading from deviation surveys. DLS is calculated using measured depth, inclination and azimuth. DLS describes the normalized estimate of the overall curvature of the well bore between two directional survey points. DLS is the number of degrees in 100 foot increments that the well bore varies.

The azimuth directly impacts the DLS. Azimuth changes during drilling can create a cork screw path. Azimuth changes in areas of the well bore with high inclination create severe doglegs resulting in extreme side loading. Side loading is a function of measured depth, axial loading, buckling tendencies and DLS rates. Side loading is measured in pounds force (lbf). DLS and depth affect side loading on the rod string. Some design programs predict higher side loads when the DLS is closer to the top of the well.

Murphy's best practice originally was to install rod guides at depths where side loading was greater than 40 lbf. The side loading is calculated by the rod design program utilizing as drilled deviation surveys. The tubing failure frequency was higher than expected using this practice. Tubing failures occurred at depths where side loading and DLS were not considered high.

Murphy learned the as drilled deviation surveys were not always representative of the actual well bore geometry. This discovery was confirmed by running gyroscopic deviation surveys. The gyro surveys were run in wells with high DLS in the as drilled deviation survey. Gyro surveys take deviations readings more frequently than as drilled surveys. Drilling surveys collect deviation data every 100 ft. Gyro surveys sample every 5 to 25 ft. providing granularity to the data.
A comparison of DLS and side loading predictions made using a gyro survey versus an as drilled survey showed interesting differences. A Murphy example well shows the difference in the calculated DLS and side loading. The dogleg spikes are higher when the gyro survey data is used in the calculation. The result of higher DLS is larger side loading force. The side loading difference is higher by 260 lbf in one area of the example well. (Fig. 8)

Murphy conducted a trial to evaluate the differences between a gyro survey run in tubing set in compression, tubing set in tension and in casing versus the as drilled survey. There are slight differences in the surveys. The doglegs seen in the gyro surveys are still present whether run in the tubing or the casing. Casing and tubing in the well did not smooth out or reduce the severity of the doglegs. (Fig. 9)

These differences are seen in numerous comparisons of gyro data versus as drilled data. The comparisons suggest as drilled deviation surveys collected at 100 ft. intervals miss inclination and azimuth changes. These changes result in micro doglegs. These micro doglegs cause unexpected tubing failures and shorter than expected run times.

TUBING SCANNING

Tubing scanning during a workover is a standard part of the Murphy repair procedure. Tubing scanning establishes a base line of wear for the tubing string. The scanning process shows wall loss in the tubing due to rod wear and pitting. Murphy's standard is to lay down any joints with wall loss greater than 30 percent. Murphy has scanned over 90 tubing strings.

The data obtained from the tubing scan is entered into the failure data base. A review of the tubing scans showed wear patterns in the tubing typically occurs in a bell shape. The installation of partially guided rods strings in areas of high side loading often caused the slick rods to be pushed into the tubing wall causing a tubing failure.

The technology of the tubing scanning equipment is important to quality data. One model of tubing scanning equipment is best used for detecting wall loss around the circumference of the tubing. This type of wall loss is mainly pitting from corrosion. Scanning equipment capable of detecting both circumferential and longitudinal wall loss is preferred. The latter type of wall loss is seen in rod pumped wells because of contact with the sucker rod coupling.

A tubing scan from a Murphy well shows pitting on the left side of the log track. Rod wear is displayed on the right side of the log track. Pitting is detected at the top of the tubing string in this example. Wall loss because of coupling contact with the tubing is seen at several depths. (Fig. 10)

Murphy utilizes a proprietary rod guide software available in the industry. The software provides assistance in the proper placement of rod guides in deviated wells. The software is used for rod guide placement in new SRP installations and repairs.

The rod guide software graphs the DLS, inclination and side loading calculated from provided well data. The as run guided rods are included in the display for a repair job. The tubing scan is included in the output if collected during the workover.

A review of the as run data from a Murphy well showed the guided rods were not placed in the areas of high side loading. The tubing scan detected wall loss at depths were the side loading was less than 50 lbf. (Fig. 11) This could indicate the presences of micro doglegs not captured in the as drilled deviation survey.

The result is sucker rod coupling contact in an unguided portion of the rod string. The wall loss in this area could be the guided rods forcing the unguided rods into the tubing wall. A workover on the example well discovered split tubing joints at a depth of 3,124 to 3,189 ft.

The rod guide software recommended the installation of a fully guided rod string. The software details the number of guides per rod in the recommendation. (Fig. 12)

CASE STUDY

A case study was conducted on a Murphy well with a history of tubing failures. A slick rod string was installed in the well during 2012. The as drilled deviation survey was used in the rod design program. The design program output shows an area of side loading over 100 lbf at 9000 to 9500 ft. A DLS of 2^{o}/100 ft. exists at the same depth. (Fig.14) The well developed a hole in the tubing after 188 days of run time. A split tubing joint was found in the well at a depth of 9,856 ft. during the repair work. (Fig. 13)

The tubing was scanned during the workover. Six joints of tubing were removed from the string based on the wall loss greater than 30 percent. The daily workover report noted that coupling wear began at 8479 ft., a worn rod was found at 9,409 ft. and worn couplings from 9,409 to 11,188 ft.

The tubing scan was performed with the type of tool that measures circumference and not longitudinal wall loss. The tubing scan did not detect the expected wall loss. There was no correlation between the tubing scan results and the visual inspection of the worn sucker rod couplings and rod guides. (Fig. 14) During the tubing repair job, 1,000 ft. of guided rods were installed from 9,030 to 10,030 ft.

The tubing failed again 42 days after the first repair. During this workover, 33 of the 40 guided rods were removed due to worn guides. A split joint was found at 10,650 ft. The failure likely occurred because tubing with significant wall loss was left in the well during the first repair job.

The daily workover report noted severe paraffin on the rods and tubing. The tubing was pulled but not scanned this time. The tubing was hydro tested back in the hole to 5000 psig. Three more joints were split during hydro testing. A partially guided rod string was installed in the well.

The case study well operated 467 days before the next tubing failure. During this repair job, a split joint of tubing was found at 10,269 ft. Rod guides were missing from some of the ¾" rods. The tubing was scanned with different scanning equipment. A total of 107 joints of tubing were removed from the well because of wall loss. (Fig.15)

The well is currently operating with a fully guided rod string based on the recommendation of the rod guiding software. The guiding software output displays a summary of the rods pulled out of the well. A recommended run – in design is displayed in the output. The software documents the locations of tubing splits and sucker rod coupling wear. (Fig. 16) The mean time between failures (MTBF) for this well is 232 days. The current operating period has not surpassed the MTBF.

This lessons learned from the case study led to the development of a rod guide strategy.

MURPHY'S BEST PRACTICES

Murphy Oil Corporation has a strategy for rod guiding in the Eagle Ford shale. The case study illustrated the need for the strategy. The lessons learned during repairs of the tubing failures are captured in the failure data base. The failure data identifies trends in failure frequency. The implementation of a rod guide strategy decreased the failure frequency of the tubing system by 22 % in 21 months.

Fully guided rod strings are now the standard to reduce failure frequency and extend run times. Gyro deviation surveys (25 foot data) are run in wells with particularly high dogleg severity based on the as drilled survey. The recommendations from rod guiding software are used for the number of guides per rod and placement of guides in each well.

A tubing scan is completed during workover operations when the tubing is pulled. Tubing with wall loss greater than

30 % is removed from the well and replaced with new or yellow band tubing. The rods and couplings are visually inspected during the workover.

Rods that have shoulder wear and worn or damaged guides are removed from the well. Replacement rods are installed based on the recommendation of rod guiding software. Worn couplings are an indicator that tubing wall loss is expected. The decision to pull tubing during a workover is made based on the condition of the rods, couplings and guides. The practice of installing guided rods in worn tubing will result in premature tubing failures.

Murphy now views rod guides as a critical piece of the sucker rod pump system. The artificial team works closely with the vendors to stay current with changing technology and materials. The vendors are partners to the long term success of the rod pump wells. The goal being reduced failure frequency across all components of the rod pump system.

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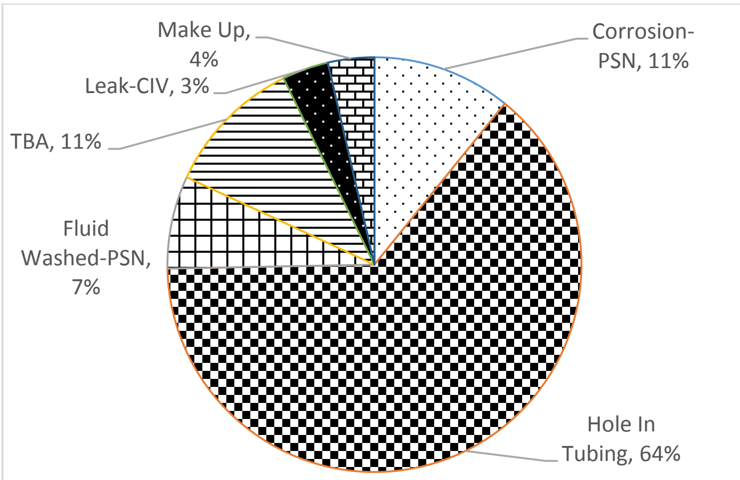

Figure 1 - Tubing System Failures 2012-2015

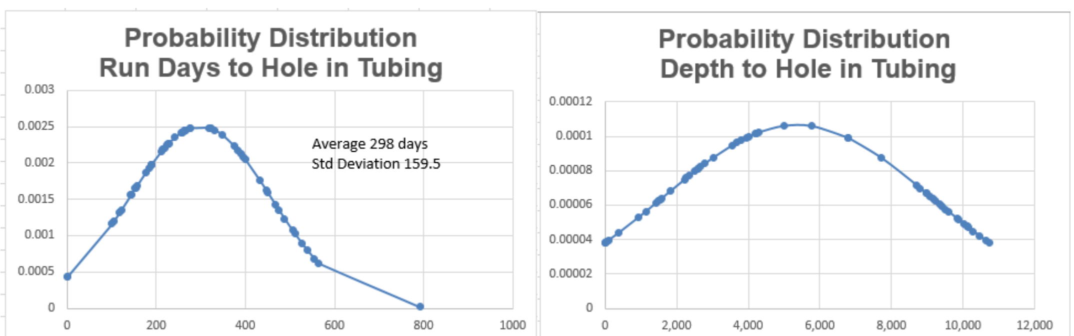

Figure 2 - Probability Distribution of Holes in the Tubing


Figure 3 - Rod pin pulled out of worn coupling

Figure 4 - Flat coupling

Figure 5 - Worn rod shoulder

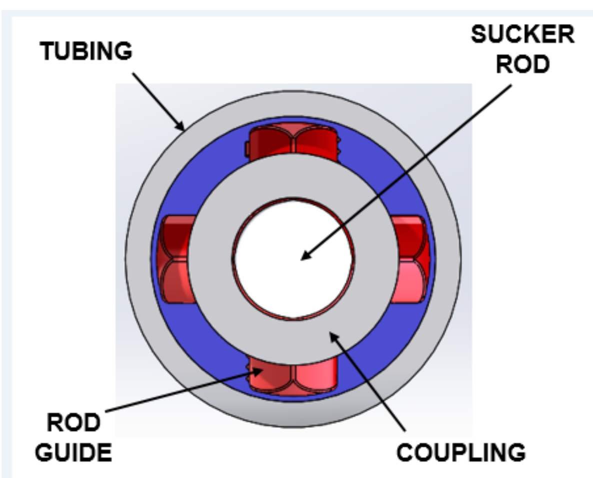

Figure 6 - Erodible wear volume of rod guides in tubing

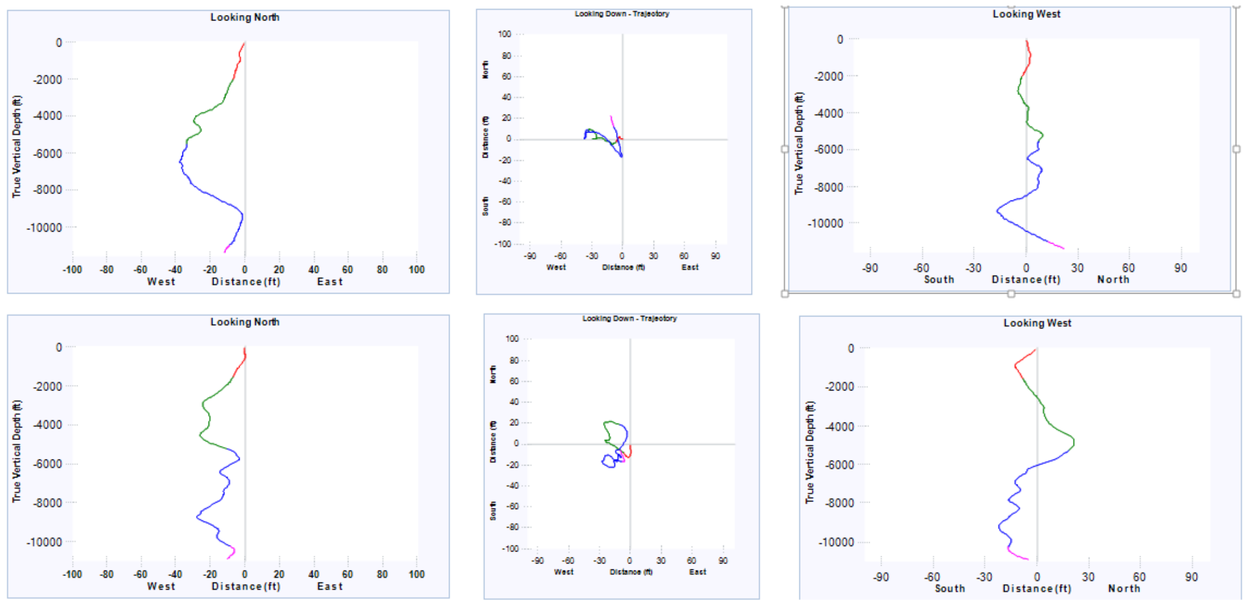

Figure 7- Representative wellbore geometry in vertical section

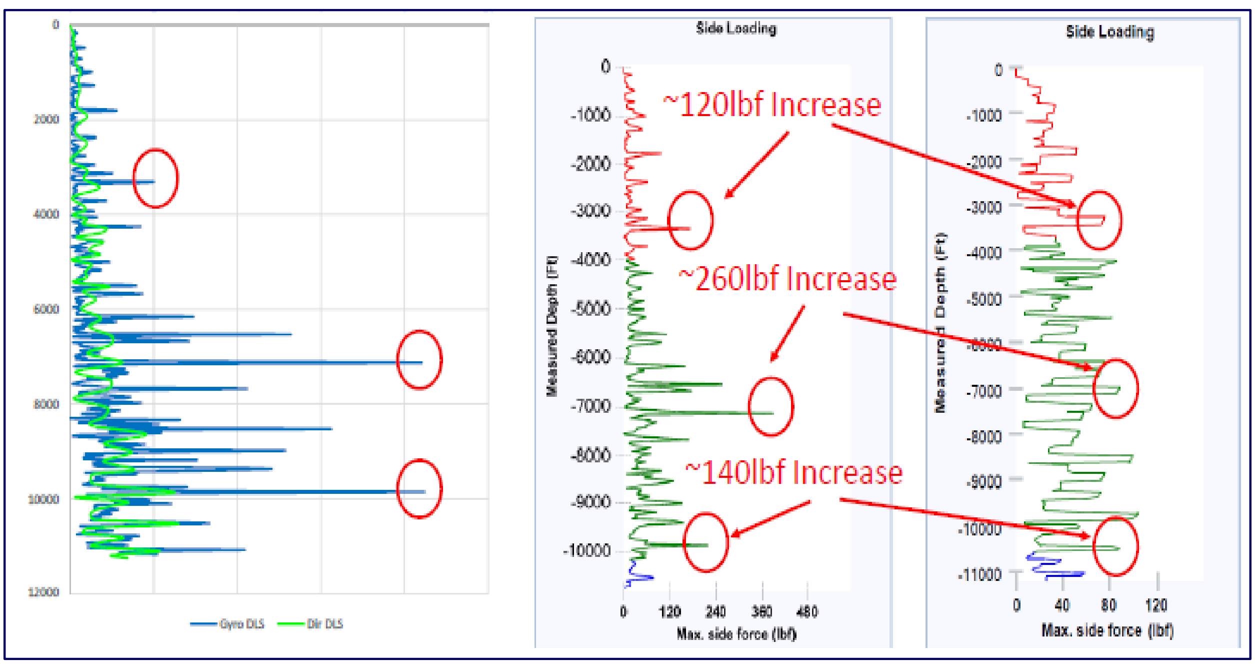

Figure 8 - Comparison of Dogleg severity and side loading calculated from as drilled deviation survey and gyro deviation survey

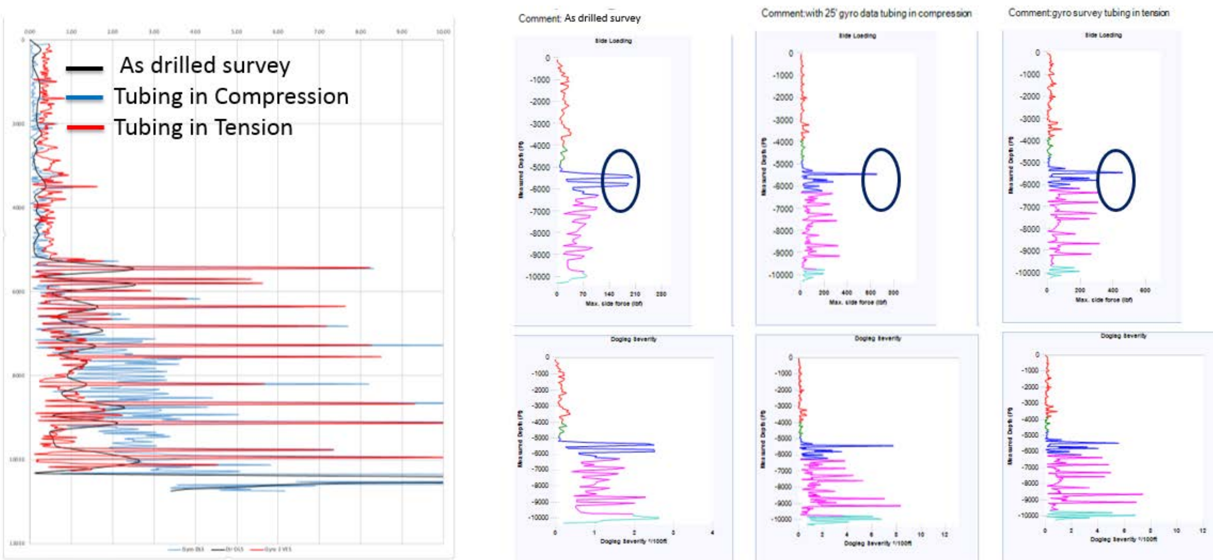

Figure 9 - Comparison of tubing in compression versus tubing in tension with gyro survey

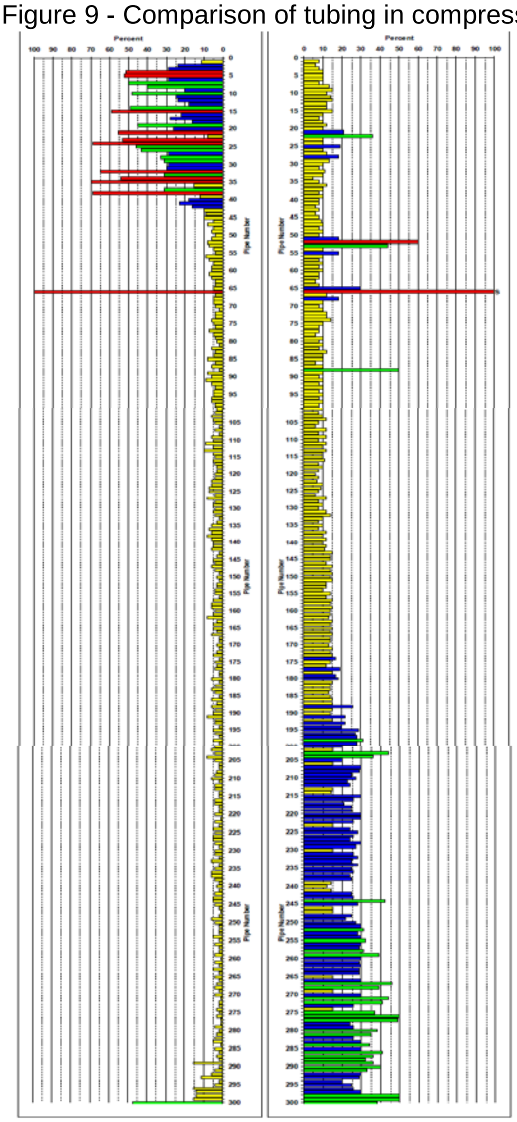

Figure 10- Example of tubing scan

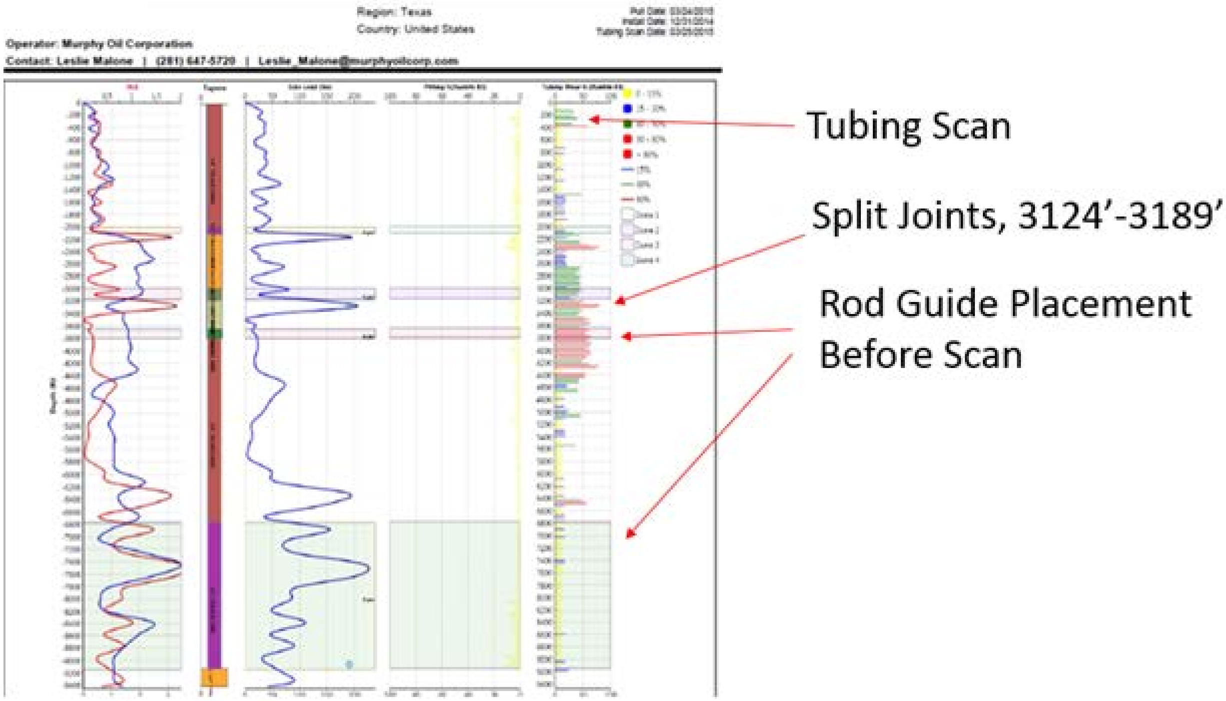

Figure 11- Rod guide placement before tubing scan

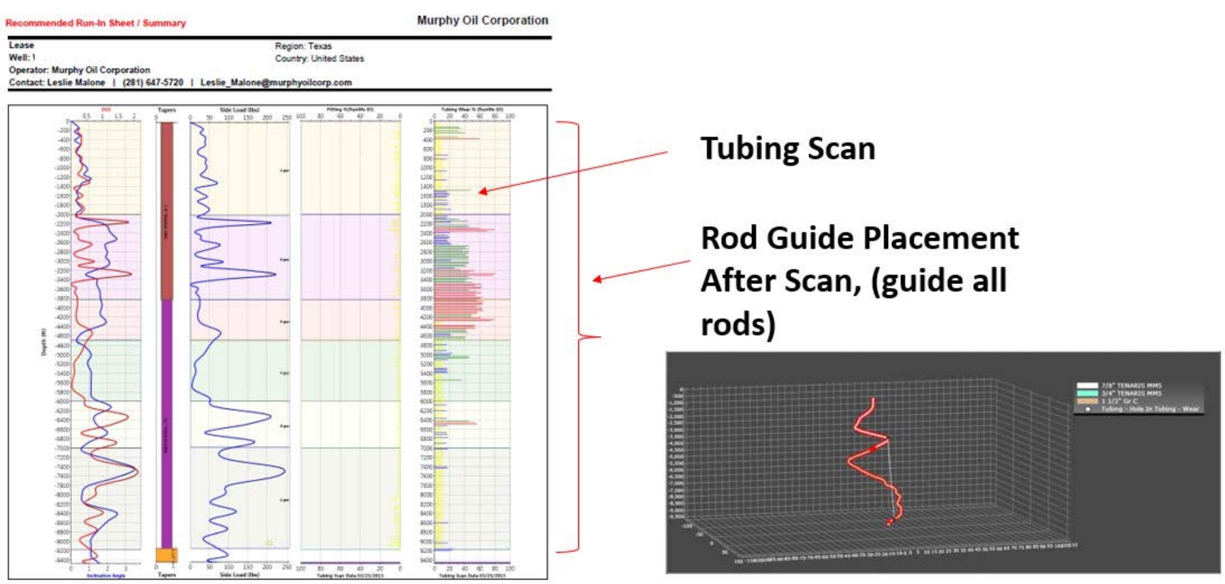

Figure 12 - Rod guide placement based on tubing scan and rod guide placement software

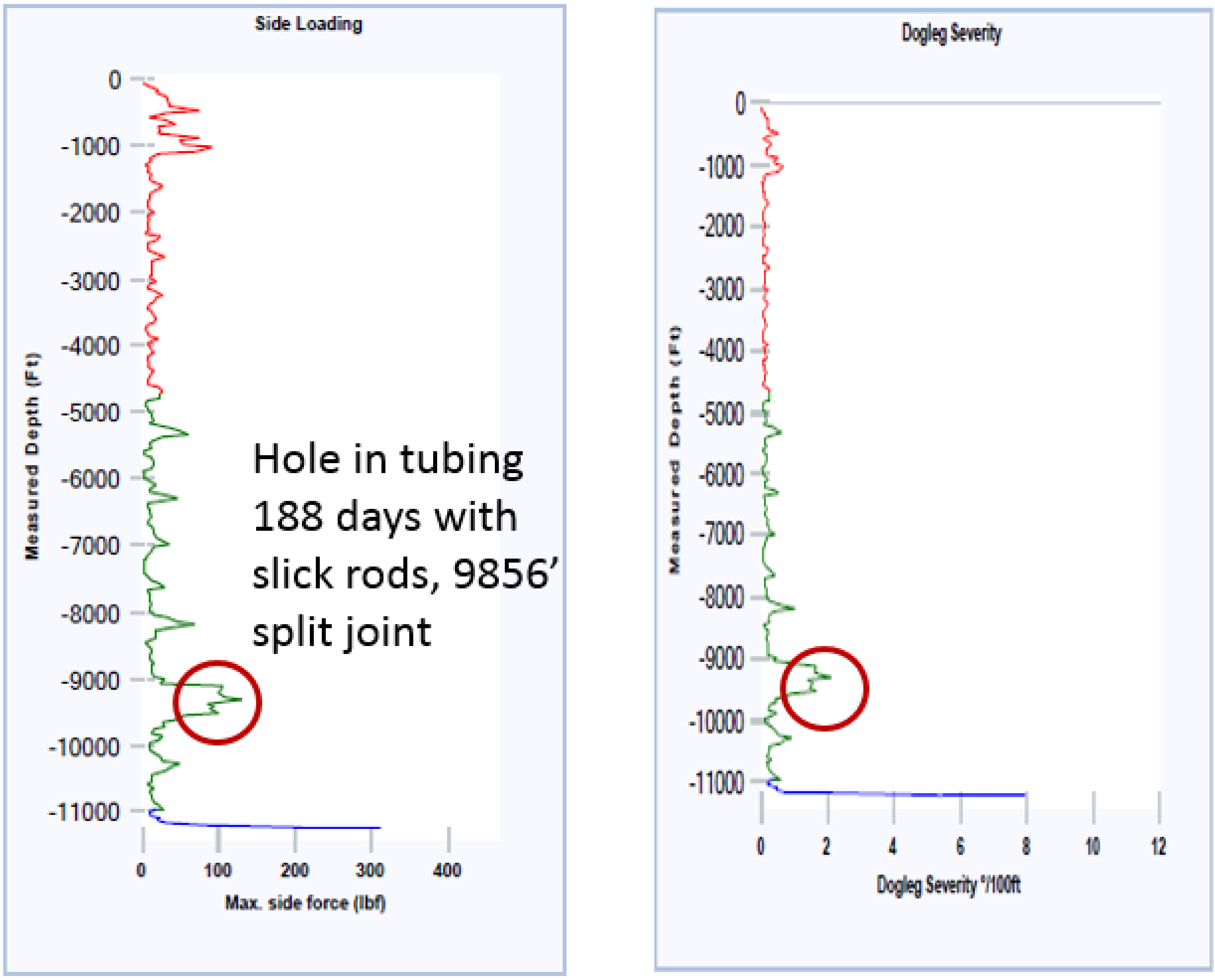

Figure 13 - Case Study DLS and side loading

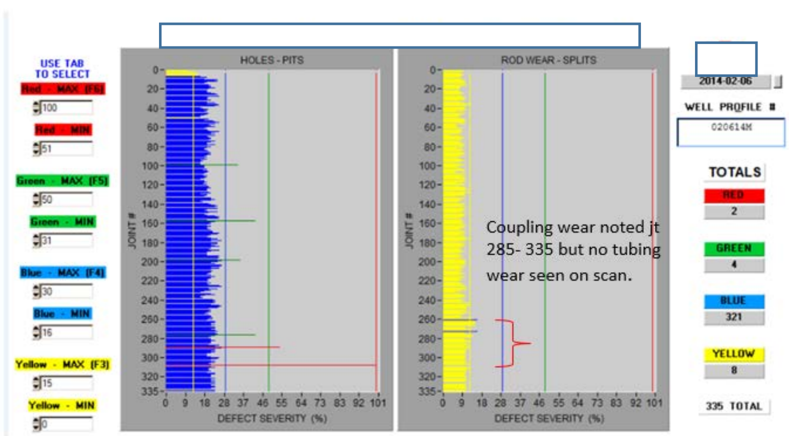

Figure 14 – Case Study first tubing scan

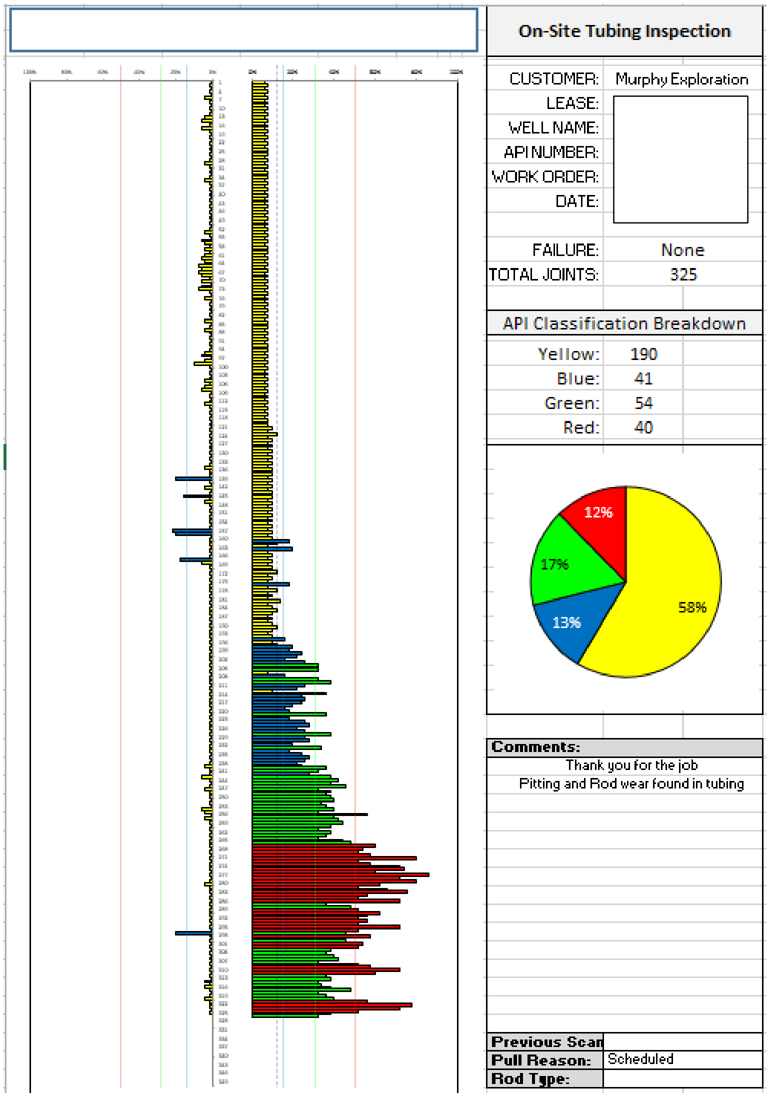

Figure 15 – Case Study second tubing scan